Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

PLAINS CO_2 REDUCTION PARTNERSHIP PHASE III FINAL REPORT

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Plains CO_2 Reduction (PCOR) Partnership

Energy & Environmental Research Center (EERC)

PLAINS CO_2 REDUCTION PARTNERSHIP PHASE III FINAL REPORT

ABSTRACT

The Plains CO_2 Reduction (PCOR) Partnership led by the Energy & Environmental Research Center (EERC) was formed as part of the Regional Carbon Sequestration Partnerships (RCSP) Program initiated by the U.S. Department of Energy (DOE) in 2003. The RCSP Program supports the deployment of carbon capture and storage (CCS) as an essential technology to mitigate greenhouse gas emissions, with emphasis on the geological storage of carbon dioxide (CO_2). This report summarizes the results from Phase III of the PCOR Partnership (2007 to 2018), including large-scale field testing to confirm that projects of at least 1 million metric tons (Mt) of captured CO_2 per year can achieve safe, permanent, and economical storage. The PCOR Partnership includes more than 120 member organizations from the public and private sector and covers a region that includes all or parts of nine U.S. states and four Canadian provinces. The overall mission of the Phase III program has been to 1) gather characterization data to verify the ability of the target formations to store CO_2, 2) facilitate the development of the infrastructure required to transport CO_2 from sources to injection sites, 3) facilitate sensible development of the rapidly evolving North American regulatory and permitting framework, 4) develop opportunities for PCOR Partnership partners to capture and store CO_2, 5) facilitate the establishment of a technical framework by which carbon credits can be monetized for CO_2 stored in geologic formations, 6) continue collaboration with other RCSPs, and 7) provide outreach and education for CCS stakeholders and the general public.

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EXECUTIVE SUMMARY

Funded by the U.S. Department of Energy and managed by the Energy & Environmental Research Center (EERC) in Grand Forks, North Dakota, the Plains CO_2 Reduction (PCOR) Partnership has become the leading carbon capture, utilization, and storage (CCUS) forum in the northern Great Plains region of the United States and Canada, with an extensive membership of over 120 organizations drawn from industry, government, and other stakeholders. This report summarizes Phase III (2007 to 2018) of the PCOR Partnership Program, including a large-scale field test at the Bell Creek oil field, a CO_2 enhanced oil recovery (EOR) project operated by Denbury Onshore LLC. The Phase III work package addressed seven objectives as follows.

1. Ability of geological formations to store CO_2: The comprehensive assessment of approximately 5.9 Mt of associated CO_2 storage at the Bell Creek oil field, combined with detailed assessments of dedicated storage at the Zama, operating Aquistore, and proposed Fort Nelson projects in Canada, have demonstrated the effectiveness of implementing an adaptive management approach (AMA) to assess and validate CO_2 storage. These site-specific assessments combine with extensive Phase III characterization efforts to underscore the regional potential to store decades of anthropogenic CO_2 emissions captured from large CO_2 sources. Estimated CO_2 storage resources in the region are between 340 and 1100 Gt in deep saline formations and between 1.5 and 9.0 Gt in selected oil fields considered most suitable for CO_2 EOR.

2. Capture and transport of CO_2: Regular updates provided by EERC staff have kept PCOR Partnership members abreast of technological and economic developments as research efforts and early demonstration projects within the PCOR Partnership and elsewhere strive to increase the efficiency and reduce the cost of CO_2 capture processes.

3. Facilitate development of regulations and permitting: Phase III efforts included regular "roundups" of regulatory developments across the region and beyond, including model procedures developed by the Interstate Oil and Gas Compact Commission. Technical work undertaken within the PCOR Partnership Program provided a valuable resource to the North Dakota Industrial Commission in eventually gaining Class VI primacy regarding CO_2 injection wells.

4. Facilitate opportunities for CCUS deployment: Knowledge sharing with and between member organizations has contributed to identification of CCUS and related market opportunities in the region and beyond, building a base to help monetize CO_2 storage. Multiple emerging CCUS projects in the region are under development, associated with coal-fired power stations, ethanol production, CO_2 EOR, and dedicated storage in deep saline formations.

5. Establish a technical framework for monitoring, verification, and accounting (MVA) of storage: Detailed monitoring undertaken at Bell Creek (5.9 Mt), Aquistore (160 Kt), and the Zama oil field in Alberta (65 Kt) has demonstrated the effectiveness of MVA technologies in tracking CO_2 distribution in the reservoir as part of the AMA. Comprehensive environmental monitoring at Bell Creek has demonstrated the integrity of storage.

6. Collaboration and knowledge sharing: The PCOR Partnership has collaborated extensively with other RCSPs and the wider international CCUS community. An example is the publication of a series of best practices manuals covering all aspects of the AMA, aimed primarily to inform nontechnical specialists of the basis and needs for storage assessment. Another example is the forthcoming special issue of the *International Journal of Greenhouse Gas Control*, with ten peer-reviewed papers focusing on the assessment of associated storage of CO_2 with EOR.

7. Providing outreach and education: the PCOR Partnership has demonstrated the value of collaboration through the dissemination of a consistent CCUS story, with publications including a CCUS regional atlas (currently 5th edition revised), workshops, interaction with schools, and broadcasting/distribution of documentary films.

Working with a Technical Advisory Board comprising independent technical and business experts, the EERC developed the following key messages from Phase III work:

- ***The PCOR Partnership has collaborated with a growing membership of over 120 industry, government, and research organizations to encourage the commercial deployment of CCUS in the PCOR Partnership region as an essential technology to manage CO_2 emissions.***
- ***The PCOR Partnership region has suitable geology, an abundance of fossil fuel resources, and an industrial and energy development base that combine to provide an ideal opportunity to deploy CCUS as a carbon management strategy.***
- ***Carefully selected and monitored storage sites present very low and manageable levels of risk to human health, the environment, and other natural resources.***
- ***Technology already developed by industry, supplemented by other innovative techniques, can be used to monitor injected CO_2 and provide assurance that the environment is not being impacted.***
- ***Storage associated with EOR can provide economic benefits, extending the life of existing oil fields while reducing emissions.***
- ***Adoption and development of communication best practices has increased public awareness of CCUS in North Dakota and the wider region through an active, multifaceted outreach program.***

Our vision for the potential future of the PCOR Partnership sees an expanding need for knowledge sharing and collaboration with members as CCUS project deployment in the region gathers pace. Financial incentives such as the 45Q federal tax credits and increased confidence in regulatory oversight, highlighted recently by Class VI primacy in North Dakota, are prompting increased interest in CCUS from fossil fuel-based industries. In addition to the power generation sector, industrial sources such as ethanol production facilities are increasingly a focus for CCUS projects. Continuation of applied R&D, with a focus on support for the development of surface and subsurface infrastructure, plays a vital role in supporting CCUS project deployment. Research efforts directed toward cost reduction for all elements of the CCUS chain can also maintain momentum for CCUS projects moving forward. A priority focus for future subsurface R&D is the development of monitoring technologies that can provide real-time, integrated interpretation of processes in the subsurface. Allied to the rapid evolution of machine learning, such techniques can make a significant contribution to the management of large-scale CO_2 injection and storage operations.

PLAINS CO_2 REDUCTION PARTNERSHIP PHASE III FINAL REPORT

1.0 INTRODUCTION

The Energy & Environmental Research Center (EERC) at the University of North Dakota leads the Plains CO_2 Reduction (PCOR) Partnership, formed as part of the Regional Carbon Sequestration Partnerships (RCSP) Initiative established by the U.S. Department of Energy (DOE) in 2003. The RCSP Program supports the deployment of carbon capture and storage (CCS) as an essential technology to mitigate greenhouse gas (GHG) emissions, with emphasis on the geological storage of carbon dioxide (CO_2). The term CCS refers to the capture and transport of anthropogenic CO_2 emissions for geological storage as a means to mitigate GHG emissions. The word utilization is commonly added to form an alternative abbreviation, CCUS (carbon capture, utilization, and storage), utilization being the use of CO_2 for economic purposes. Most commonly, utilization refers to enhanced oil recovery (EOR), which results in associated storage of CO_2, incidental to oil production operations. For the purposes of this report, the terms CCS and CCUS are used synonymously and interchangeably.

This report summarizes the results of Phase III of the PCOR Partnership (2007 to 2018), including large-scale field testing to confirm that projects of at least 1 million metric tons (Mt) of captured CO_2 per year can achieve safe, permanent, and economical storage.

The PCOR Partnership region comprises all or part of nine U.S. states and four Canadian provinces (Figure 1) and has attracted over 120 member organizations to provide a forum for industry, governments, and research partners to collaborate and share knowledge to support CCS deployment.

The Bell Creek oil field in southeastern Montana, an EOR site operated by Denbury Onshore LLC (Denbury), provided the large-scale field test for Phase III. The PCOR Partnership employed an adaptive management approach (AMA) to the assessment of over 5 Mt of associated CO_2 storage, incidental to EOR operations. A feasibility study for Spectra Energy Transmission near Fort Nelson in British Columbia, Canada, involving dedicated storage in a deep saline formation (DSF), provided a second technical case study for application of the AMA, although CO_2 injection has not yet proceeded. The Aquistore project in southern Saskatchewan, Canada, operated by SaskPower as a dedicated storage facility associated with the Boundary Dam project, has provided an opportunity to assess dedicated storage of over 100,000 tonnes of CO_2. The Zama Project was implemented to demonstrate the containment of injected acid gas (a mixture of hydrogen sulfide and CO_2), containing over 65,000 tonnes of CO_2, in the reservoir and subsequent geologic storage of CO_2 at an EOR site that utilized acid gas as the mobilizing fluid. Phase III has also included a range of additional activities to complement these field-based studies.

Figure 1. The PCOR Partnership region.

The PCOR Partnership Program developed seven objectives to meet the goals of DOE's RCSP Initiative:

1) Refine knowledge of the region's CO_2 production and storage potential to optimize source–sink opportunities and underscore the regional potential for the storage of decades of anthropogenic CO_2 emissions.
2) Assess technology developments and commercial CO_2 operations to facilitate infrastructure planning required for CCUS to be implemented on a regional basis.
3) Monitor regulatory developments across the region and beyond, and provide information to inform emerging regulatory frameworks.
4) Develop opportunities for CCUS deployment by identifying market opportunities in the region and beyond.
5) Establish a technical framework for monitoring, verification, and accounting (MVA) of stored CO_2.
6) Collaborate and share CCUS-related knowledge with other RCSPs and the wider international CCS community.
7) Educate the public on the facts and benefits associated with CCUS.

The following sections of the report summarize research highlights from the PCOR Partnership Phase III, covering developments in CO_2 capture, transport, storage, life cycle analysis and public outreach. Key messages from the Phase III program, determined in consultation with an independent Technical Advisory Board (TAB), are presented as conclusions to the report. Phase III activities were organized into 16 tasks, and these are described in a series of appendixes to the report (Appendixes 1–16, corresponding to Tasks 1–16). A summary of deliverables, milestones, and select publications is provided in Appendix 17. Appendixes 18 and 19 provide summaries of panel sessions held at the 2018 and 2019 PCOR Partnership Annual Meetings.

2.0 CO_2 CAPTURE AND TRANSPORT

The PCOR Partnership conducted research to support the infrastructure planning associated with the capture, dehydration, compression, and pipeline transportation of CO_2 from a large source to an end user or storage site. This effort included the investigation of 1) technologies for capturing CO_2 from various industrial and utility operations; 2) CO_2 compression needs and the various types of compressors that are available to meet them; and 3) existing and potential pipeline routes to move CO_2 from potential sources to potential storage locations within the PCOR Partnership region. Complementary to these research efforts, the EERC also monitored activities and assessed the pipeline transportation of CO_2 that were conducted by the commercial partner, Denbury, as part of the Phase III demonstration test that was conducted at the CO_2 EOR site in Bell Creek, Montana. This commercial-scale application provided valuable insight regarding the technical factors that are considered when moving CO_2 by pipeline from point of origin to the location of final disposition.

2.1 CO_2 Capture

Over the course of the Phase III program, the EERC conducted research that documented the status of carbon capture technology development and applications and tracked the emergence of new trends in CO_2 capture (Cowan and others, 2011; Jensen and Gorecki, 2018). A CO_2 capture technology "tree" diagram was developed that provided both basic technical information about existing capture technologies as well as information related to their development status, source-type applicability, and economics, if available. The technology tree diagram comprised technologies that could be applied at three different stages of combustion, 1) pre-combustion, 2) during combustion (i.e., oxycombustion and chemical-looping combustion), and 3) post-combustion. The identified technologies were organized into categories as follows (Figure 2): physical and chemical absorption; physical and chemical adsorption; oxygen-, hydrogen-, and CO_2-permeable membranes; and other processes (i.e., cryogenic processes; mineralization; and reduction [i.e., photosynthesis and chemical and biochemical reduction processes]).

New technical trends that were documented by the EERC are listed below:

- Applications of CO_2 capture technologies have begun to be investigated at industrial targets such as cement and lime manufacturing, pulp and paper production, biorefineries and ethanol production, petroleum refineries, and hydrogen production. There are

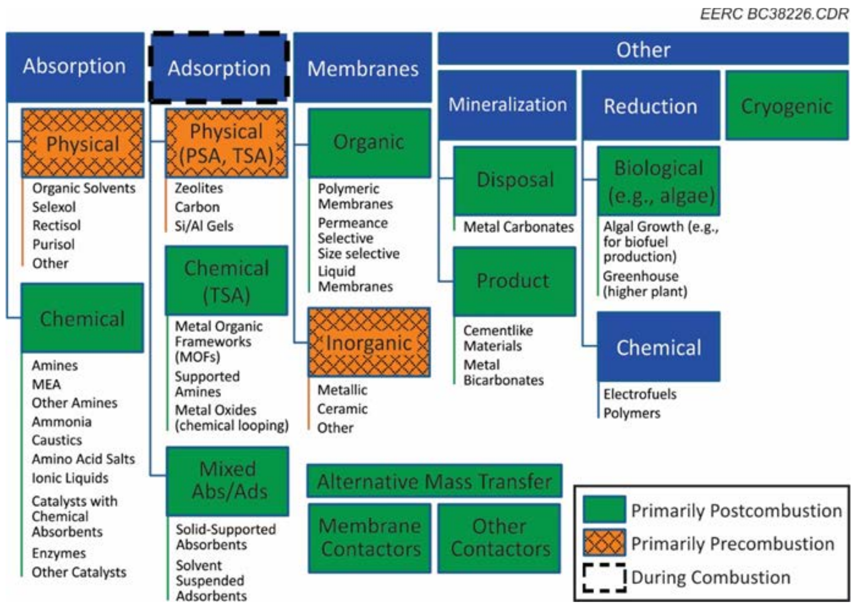

Figure 2. Categories of technologies included in the PCOR Partnership CO_2 capture technology tree (Cowan and others, 2011).

differences in CO_2 capture between power plants and industrial facilities, because of variations in CO_2 stream composition and flow rate. Important parameters that should be considered when selecting an approach for capture at an industrial facility are CO_2 stream size, constituent composition, and the potential for heat integration between the capture plant and the industrial operations.

- There has been an increase in the number of large-scale CO_2 capture projects worldwide (Global CCS Institute, 2017). These applications cover different industries, including fertilizer manufacturing, natural gas processing, synthetic natural gas production, liquid natural gas production, hydrogen production, power generation, bitumen upgrading, steel manufacturing, and ethanol production, demonstrating that commercial implementation of CO_2 capture in a variety of industrial settings is possible. In general, solvent-based technologies are the most common means to capture CO_2 from industrial processes and are especially well-suited for retrofitting existing plants.

- Even though much of the current CO_2 capture research involves the scale-up of the most promising technologies, as many as 13 new and novel techniques are under development (Jensen and Gorecki, 2018). Some technologies specifically target certain industries, such as the Calix Flash Calcination technology for cement production. Others, such as the supercritical CO_2 (or Allam) cycle, offer a completely different way to capture CO_2 from various types of industrial plants.

Additional research and technology demonstrations can increase the pace of the commercial deployment of CO_2 capture technology. In addition, new legislation is required to provide increased financial certainty and catalyze investment in projects. One such piece of legislation is

Senate Bill 1535 (Furthering carbon capture, Utilization, Technology, Underground storage, and Reduced Emissions Act [the FUTURE Act]). This bill, which extends and modifies the 45Q tax credit for CCS, has the potential to remove the cost barriers to deployment of CO_2 capture technology, reduce the commercial risk for early technology adopters, and reduce the costs over time as more is learned about developing, financing, constructing, and operating CO_2 capture projects. The bill was passed on February 9, 2018, as part of H.R. 1892 (Bipartisan Budget Act of 2018, 2018).

While more remains to be done, continued creative problem solving, increased government and private investment, and the reduction of both financial barriers and commercial risk appear to be creating a resurgence in interest in CCUS technologies in the United States.

2.2 CO_2 Compression and Transportation

The majority of the CCS research to date has focused on capture, injection, and subsequent monitoring of CO_2 in the subsurface. There are, however, many challenges associated with both compression and transportation of CO_2, which can add significantly to the cost of CCS. The EERC conducted research on both of these topics, with the goal of minimizing cost impact and advancing widespread CCS commercialization.

2.2.1 Compression

CO_2 compression plays an important role in the total capital requirement of, and energy penalty associated with, CO_2 capture technology. Different capture technologies produce CO_2 streams at different pressure and temperature conditions, affecting compression requirements. Compressors produce varying quantities of heat, with the potential for use in the capture process. Most compression incorporates CO_2 stream dehydration through condensation of water in the compression intercoolers, in a separate dehydration step, or both. The EERC and others have recognized the potential for optimizing the integration of compression and dehydration into a capture system to reduce cost and energy impacts on the overall efficiency of a power plant or industrial process.

The EERC participated in several workshops (e.g., Workshop on Future Large CO_2 Compression Systems held in Gaithersburg, Maryland, in March 30–31, 2009) and conducted research on opportunities and challenges associated with CO_2 compression (Jensen and others, 2011; Jensen and others, 2015a; and Jensen and others, 2017). An in-depth investigation of improved compression efficiency identified two approaches: 1) the use of a compression–liquefaction–pumping pathway, and 2) the application of a novel, advanced compressor, the Dresser-Rand SuperCompressor, which is based on shock compression theory and can achieve very high compression efficiency at high single-stage compression ratios (on the order of 8:1 to 10:1).

Based on these efforts, the EERC has concluded the following:

- Centrifugal compression appears to be the most appropriate for use with CO_2 capture applied at all three stages of combustion (precombustion, during combustion, and postcombustion).
- The shock wave compression offered by the Dresser-Rand SuperCompressor is better suited to postcombustion than precombustion and is not at all appropriate for oxycombustion applications.
- Placement of the dehydration step within the compressor train affects the ability to use the heat produced during compression as well as the compressor design.
- The best plant efficiency and capture economics will be achieved by integrating the capture technology, dehydration, and compression and integrating the compressor waste heat into the overall plant (e.g., the Dresser-Rand SuperCompressor offers the opportunity for significant waste heat recovery).

Further studies of the effects of various dehydration schemes on compression could be of further value when determining the best approaches to efficiently and cost-effectively integrate the entire CO_2 capture system into a power plant or industrial facility. Additional studies of the integration of the Dresser-Rand SuperCompressor into a capture facility are also recommended, as the SuperCompressor is sufficiently different from other compressor technologies to require a fresh examination of how dehydration and integration into the plant of the considerable quantity of usable heat generated could be most effectively utilized.

2.2.2 Transportation

Pipeline transportation was examined with a preliminary economic assessment of early, wide-scale deployment of CCS in the PCOR Partnership region. A subsequent effort estimated the schedule and costs of a CO_2 pipeline in the PCOR Partnership region, following the most likely routes of a national pipeline network with subsequent secondary and feeder lines (Jensen and others, 2009; Jensen and others, 2012; Jensen and others, 2013). The EERC also investigated the possibility of defining a universal CO_2 pipeline specification applicable to a majority of capture technologies, considering purity requirements of potential end users and the processes required to meet these requirements. As part of the PCOR Partnership Phase III demonstration test at Bell Creek, the EERC monitored the construction and operation of the 373-km (232-mile) Greencore Pipeline, which transports more than 1.4 million m^3/d (50 MMcfd, equal to 2630 t/d) of CO_2 from the capture operations at natural gas-processing plants in Wyoming.[1]

[1] The pipeline is designed to transport as much as 20.5 million m^3/d (725 MMcfd), or 38,150 t/d (42,053 tons/d) of CO_2.

2.2.2.1 Pipeline for Early Implementation of CO_2 Capture in the PCOR Partnership Region

The EERC conceptually developed a route for, and estimated the cost of, a regional pipeline network required for the most likely early wide-scale deployment of CCS in the PCOR Partnership region. This research effort was conducted using a pipeline-routing model developed by the Massachusetts Institute of Technology (MIT) (Massachusetts Institute of Technology, 2007). The modeling focused on three CO_2 source types that are well represented in the PCOR Partnership region: gas-processing plants, ethanol production plants, and coal-fired power plants. A pipeline network was developed by adding the emitted annual mass of CO_2 from one source to the next closest source. This process was repeated to form feeder lines and minor and major trunk lines for each of the states and provinces in the PCOR Partnership region. The pipelines were routed toward the geologic sinks and connected at the borders of the states and provinces. The capital and construction costs of this hypothetical 9900-mile pipeline network were estimated to be $11.5 billion; operations and maintenance costs were estimated to be about $50 million annually (Jensen and others, 2009).[2]

2.2.2.2 Phased Build-Out of CO_2 Pipeline Network for PCOR Partnership Region

Many of the large CO_2 sources in the PCOR Partnership region are not located near appropriate geologic storage areas, making it likely that a regional pipeline network would be needed to transport the CO_2 from the sources to the storage sites. Any network would likely be built in stages or phases, with the first phase consisting of pipeline segments that connect sources with EOR opportunities, followed by the addition of other sources and sinks as dictated either by the marketplace (in the case of EOR) or national or regional carbon management policy.

The EERC developed a four-step, phased pipeline-planning methodology to compare hypothetical pipeline routes by estimating the amount of CO_2 that can be stored, as well as the length and cost of the trunk pipelines required to store that CO_2 (Jensen and others, 2012; Jensen and others, 2013). This development methodology was applied to the PCOR Partnership region to estimate a hypothetical pipeline network that could be implemented in phases over the next 40 to 50 years. The volume of CO_2 that would be available from each cluster of sources was determined for three periods (up to 2035, from 2035 to 2050, and after 2050), and the most likely storage targets for each source cluster were identified. Hypothetical pipeline routes connecting the sources and storage sites were determined. Finally, the routes were optimized for each phase of network development considering the region as a whole (notwithstanding the significant public and/or private investment that would be required to realize this type of infrastructure).

The results of this effort determined that a hypothetical pipeline network of trunk lines (Figure 3), roughly 6700 mi in total length, could transport sufficient quantities of CO_2 such that the International Energy Agency (IEA) BLUE Map scenario (International Energy Agency, 2010) could be met for the PCOR Partnership region by 2050. This represents a reduction in CO_2 emissions of 50% over 2005 levels by 2050, or 445 million tonnes/yr of CO_2.

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[2] The pipeline network was developed solely for estimating the transportation infrastructure costs and is not intended to represent an implementable pipeline system.

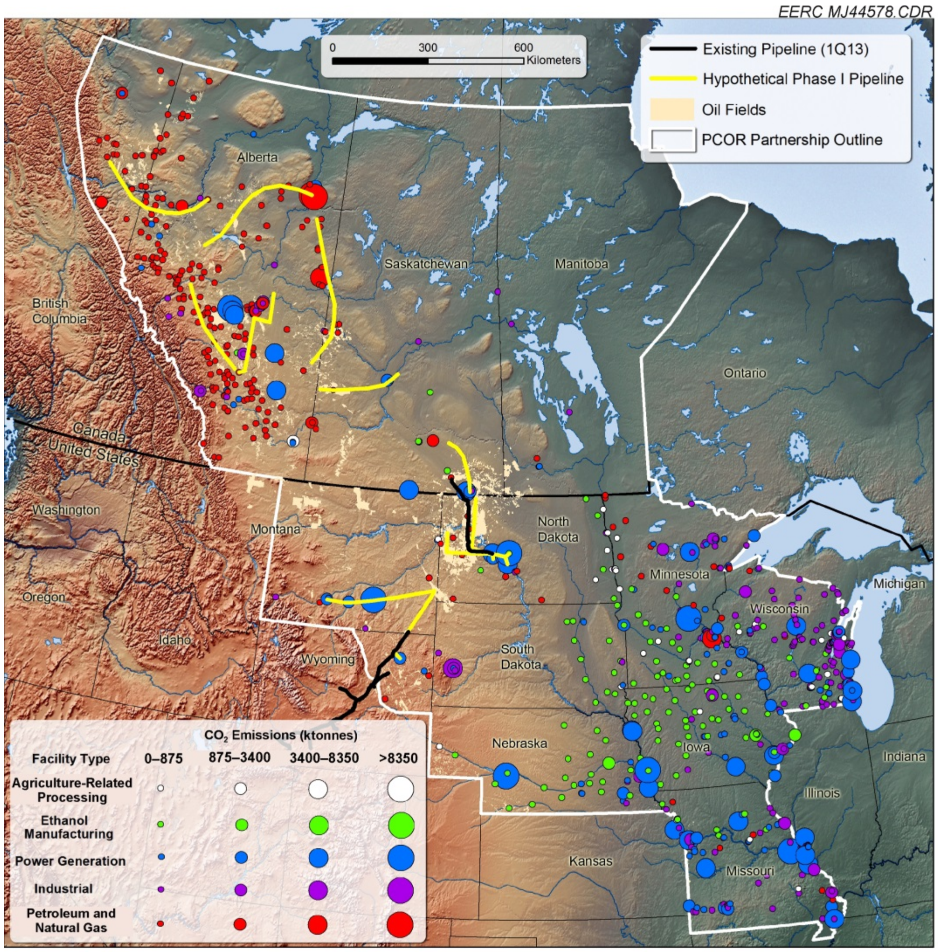

Figure 3. Hypothetical CO_2 pipeline network of trunk lines within the PCOR Partnership region.

The pipeline estimates obtained for the PCOR Partnership region using the above methodology indicate that the length of pipeline required for the U.S. portion of the PCOR Partnership region is ~3270 mi, which compares well with the estimates by Dooley and others (2009) that about ~28,000 mi of pipeline would be needed in the United States by 2050 to meet the scenario in which the atmospheric concentration of CO_2 is stabilized at 450 ppm.

This hypothetical pipeline-routing methodology developed by the PCOR Partnership is aligned with the path forward prescribed by IEA, which recommends the implementation of long-term strategies that cluster CO_2 sources and develop CO_2 pipeline networks to optimize the source-to-sink transmission of CO_2 (Jensen and others, 2013).

2.2.2.3 Development of a Universal CO_2 Pipeline Specification

The EERC conducted research to investigate the feasibility of defining a universal CO_2 pipeline specification that is applicable to the majority of capture technologies. As part of that effort, the quality of CO_2 streams that could be produced by a few of the more significant industries, the purity requirements of the different end uses for CO_2 (e.g., EOR) and the purification processes required to meet these requirements, and the effects of impurities on the pipeline infrastructure, were surveyed.

Research concluded that the implementation of a universal CO_2 pipeline specification is unlikely. Particularly problematic are wide variations in the characteristics of CO_2 sources (i.e., multiple combinations of industry sources and CO_2 capture technologies) as well as the wide range of purity requirements of the potential end users. For specific source–sink combinations (e.g., a solvent-based CO_2 capture technology delivering CO_2 to an EOR operation), pipeline specifications in the United States exist, such as the Kinder Morgan specification shown in Table 1. The specifications in Table 1 reflect both the requirements of EOR and the effects of CO_2 and impurities on the pipeline itself.

Table 1. Kinder Morgan Specifications for Pipeline Transport of CO_2 (Havens, 2008)

Species	Specification		Reason
CO_2	95 mol%	Minimum	MMP[a]
N_2	4 mol%	Maximum	MMP
Hydrocarbons[b]	5 mol%	Maximum	MMP
Water[c]	30 lb/MMcf (~600 ppm by weight)	Maximum	Corrosion
O_2	10 ppm by weight	Maximum	Corrosion
H_2S	10–200 ppm by weight	Maximum	Safety
Total Sulfur	35 ppm by weight	Maximum	Health and safety
Glycol[d]	0.3 gal/MMcf	Maximum	Operations
Temperature	120°F	Maximum	Pipeline coating

[a] Minimum miscibility pressure in an oil field.
[b] In addition, the dew point of the CO_2 stream (with respect to hydrocarbons) must be less than –29°C (–20°F).
[c] No free water; these values are for water in the vapor phase.
[d] At no time may the glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

The Kinder Morgan specifications do not have to be applied to pipelines that are only intended to carry CO_2 from a single source to a single end user. In such cases, the pipeline would be designed to tolerate the specific impurities in that stream, as in the case of the pipeline that carries CO_2 from the Great Plains Synfuels Plant to the Weyburn oil field in Saskatchewan, Canada. The Great Plains Synfuels Plant product CO_2 has a typical composition, shown in Table 2.

Table 2. Composition of Product CO_2 from the Great Plains Synfuels Plant (Perry and Eliason, 2004)

Component	vol%
CO_2	96.8
H_2S	1.1
C_2H_6	1.0
CH_4	0.3
Other	0.8
Total	100.0

Other project-specific pipeline specifications have also been put in place for other projects (Race and others, 2012). Alternatively, pipeline construction can be modified to accommodate the unique characteristics of a source. Three approaches to address issues created by impurities in the CO_2 are to 1) upgrade the pipe metal, 2) adopt lined pipe, and 3) switch to (organic polymer) composite pipe. While changing to another material might resolve impurity-related issues, other issues can arise, not the least of which is an increase in pipeline cost.

Further research on more complex stream compositions may be needed to better define CO_2 pipeline specifications that would offer the most efficient, safe, and economical transport of CO_2 while ensuring the structural integrity of the pipeline.

Ultimately, a systems analysis approach is required to determine if a focus on the impurities of a CO_2 stream that is transported via pipeline could yield an improvement in the efficiency and/or cost-effectiveness of an integrated CCS process.

3.0 STORAGE

Geologic storage of CO_2 typically involves the injection of dense-phase CO_2 (supercritical CO_2) into the deep subsurface to support CCS deployment and reduce anthropogenic GHG emissions. The main focus of PCOR Partnership Phase III activities has been demonstration of storage projects at large scale (>1 Mt CO_2 per year) and development or advancement of the technologies required for effective assessment and management of storage sites.

During PCOR Partnership Phase III, efforts were conducted to:

- Develop estimates of regional CO_2 storage resource potential.
- Assess site-specific storage resource potential.
- Develop an AMA and best practices in the aspects of site characterization; modeling, and simulation; risk assessment; and MVA with which to guide CO_2 storage projects through all phases of operation (from project planning to closure).

This section details these research efforts, with emphasis on salient results and conclusions.

3.1 Dedicated Versus Associated CO_2 Storage

CO_2 storage projects can be broadly divided into two types. ***Dedicated CO_2 storage*** (hereafter referred to as dedicated storage) involves the underground injection of anthropogenic CO_2 solely for the purpose of GHG mitigation, as part of CCS projects. The Sleipner project, in the Norwegian North Sea, has been injecting approximately 1 Mt of CO_2 per year since 1995 into a DSF, and several other dedicated storage projects are now operating at a similar large scale around the world, including the Aquistore Project operated by SaskPower and the Quest Project operated by Shell, both within the PCOR Partnership region. ***Associated CO_2 storage*** (hereafter referred to as associated storage) occurs as a result of CO_2 injection for other purposes, most commonly EOR. CO_2 EOR was first undertaken in Texas in the 1970s, and over 100 CO_2 EOR sites are now operational in the United States. The technology is also being deployed in several other countries, including Canada, Brazil, Mexico, and Saudi Arabia.

The storage of CO_2 is a result of the EOR process rather than the goal of the EOR process. During EOR operations, 50% to 60% of the injected CO_2 is produced with the recovered oil, separated and purified as needed, and reinjected for additional oil recovery. The proportion of this recycled component in the injected CO_2 typically increases with time, on a site-specific basis. Associated storage achieves an efficiency greater than 95% in storing purchased CO_2. Despite associated storage being a physical consequence of CO_2 EOR, in many cases, operators of such sites might not seek recognition of GHG mitigation benefits (e.g., credits) because of various economic, regulatory, or legal factors. CO_2 EOR projects are driven by the economic benefit of producing oil that may otherwise not be recoverable by primary or secondary production methods. Enhanced coalbed methane (ECBM) and enhanced gas recovery (EGR) operations could also lead to associated storage, although these storage scenarios remain unproven at industrial scale. Similarly, CO_2 EOR in unconventional reservoirs has yet to be proven at large scale but could offer a significant number of additional storage opportunities.

3.2 Regional Storage Resource Potential

As part of the Phase III effort, the PCOR Partnership has developed a comprehensive understanding of the magnitude, distribution, and variability of the major stationary CO_2 sources and potential CO_2 storage targets to determine the feasibility of widespread implementation of commercial-scale CO_2 storage projects. Within this effort, the EERC has refined CO_2 storage resource estimates for saline formations and EOR opportunities in the PCOR Partnership region and provided additional context for interpreting the commercial-scale implications of the results of the large-scale demonstrations.

Within the PCOR Partnership region, characterization efforts have identified significant CO_2 storage resource potential of 340 to 1100 billion tonnes (Gt) of storage in currently evaluated saline formations, 23 Gt in depleted oil field reservoirs, 1.5 to 9 Gt in selected oil fields that are candidates for CO_2 EOR, and 7 Gt in unminable coal seams, which has been estimated but remains unproven at large scale.

Important learnings from the PCOR Partnership Phase III regional storage resource potential assessment are included below:

> The PCOR Partnership has identified, quantified, and categorized 458 stationary sources in the region that have an annual output of greater than 100,000 tonnes of CO_2. Many of the large point sources are located in areas that are favorable for CO_2 storage because of their concurrence with deep sedimentary basins, such as those areas in Alberta, North Dakota, Montana, and Wyoming. A map with major sedimentary basins and locations and magnitudes of CO_2 sources in the PCOR Partnership region is shown in Figure 4.

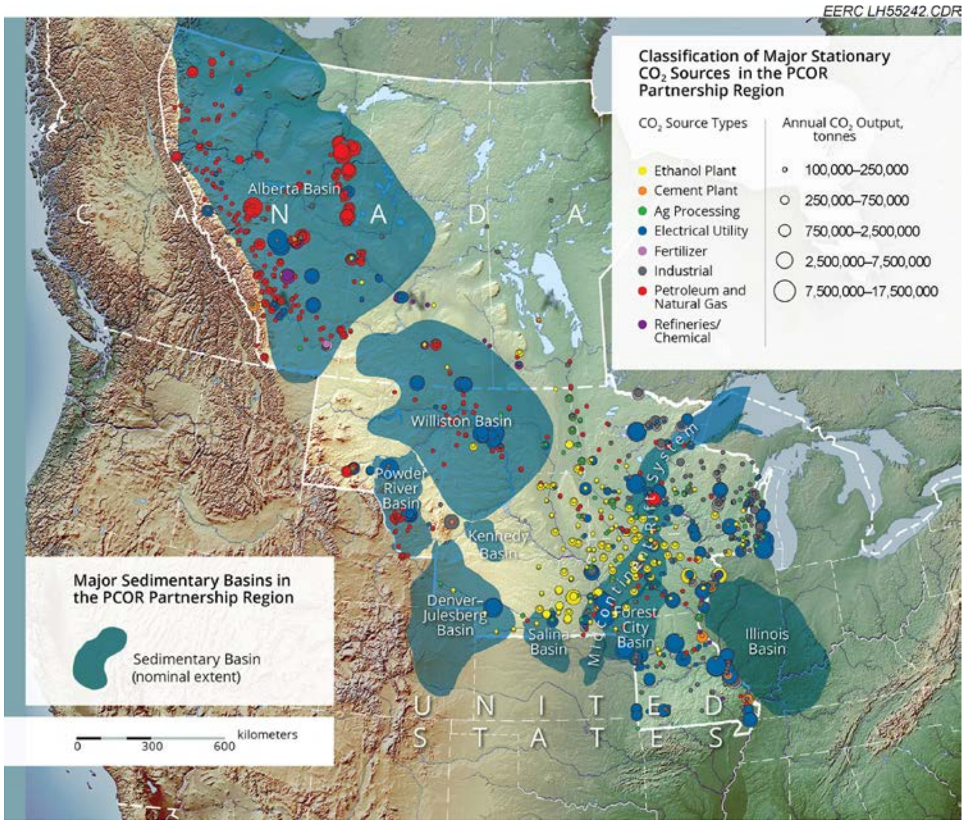

Figure 4. Major sedimentary basins and classification of major stationary CO_2 sources within the PCOR Partnership region (Peck and others, 2017).

- About two-thirds of the emitted CO_2 in the PCOR Partnership region is due to electrical energy generation. Other significant sources of CO_2 are associated with energy exploration and production activities; agricultural processing; fuel, chemical, and ethanol production; and various manufacturing and industrial activities.

- Reconnaissance-level characterization has identified at least 340 Gt of potential storage in DSFs within the PCOR Partnership region. A map showing locations of evaluated suitable DSFs in the PCOR Partnership region is shown in Figure 5.

- Reconnaissance-level CO_2 storage estimates were made for selected oil fields in the Williston, Powder River, Denver–Julesberg, and Alberta Basins. Results of the estimates for the evaluated fields (using a volumetric method) in the four basins indicate an associated CO_2 storage potential of over 3.2 Gt and 7 billion stock tank barrels (STBs) of incremental oil production. A map with locations of oil fields (associated CO_2 storage potential) and EOR potential within the PCOR Partnership region is shown in Figure 6.

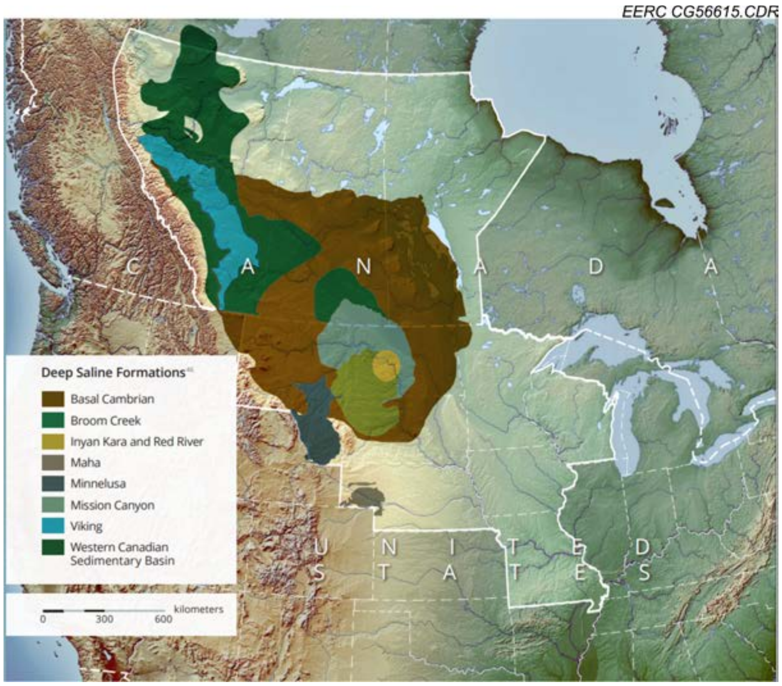

Figure 5. Evaluated suitable saline formations within the PCOR Partnership region.

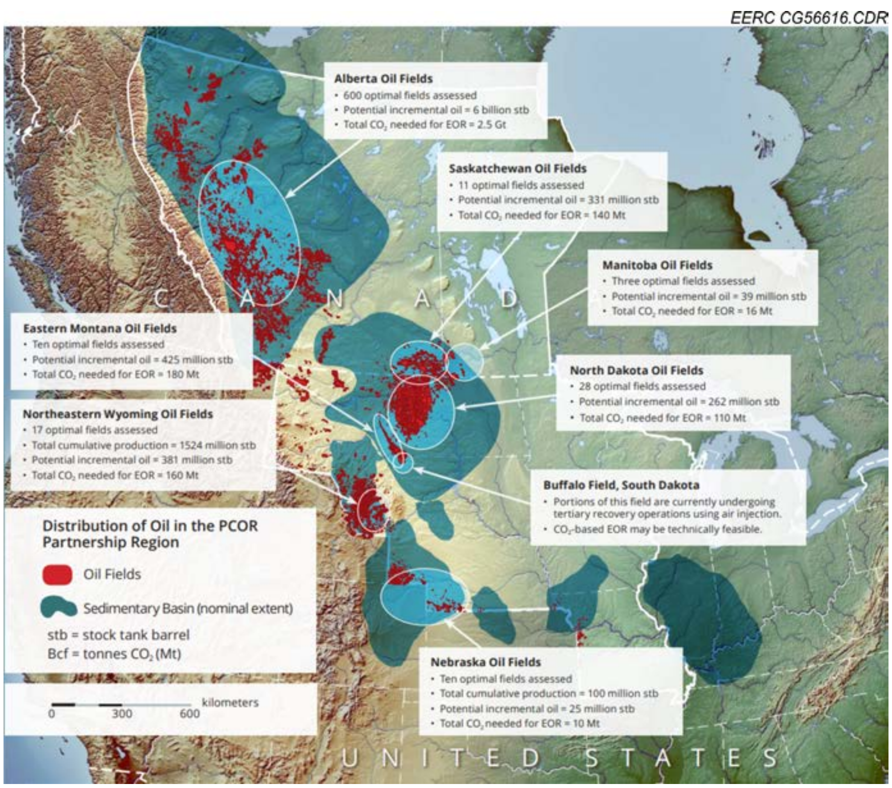

Figure 6. Associated CO_2 storage and EOR potential within the PCOR Partnership region (Peck and others, 2016).

3.3 Assessment of Storage Sites

3.3.1 Adaptive Management Approach

As the PCOR Partnership has evolved, an AMA (Figure 7) was adopted to support the development and commercial deployment of CO_2 storage projects. Two field demonstration projects were studied where the AMA was applied to: 1) dedicated CO_2 storage in a saline formation (Fort Nelson, British Columbia) and 2) associated CO_2 storage at an oil field undergoing CO_2 EOR (the Bell Creek Field located in southeastern Montana).

The AMA consists of four technical elements: site characterization, modeling and simulation, risk assessment, and MVA. Specific technical activities within these elements are conducted with varying levels of rigor during each of the phases of commercial project development (i.e., site screening, feasibility study, design, construction/operation, and closure/postclosure). As shown in Figure 7, multiple go/no-go decision points exist along the commercial development pathway of a CO_2 storage project. These important junctures allow the developer to assess the current state of the project to determine if it should continue to the next phase.

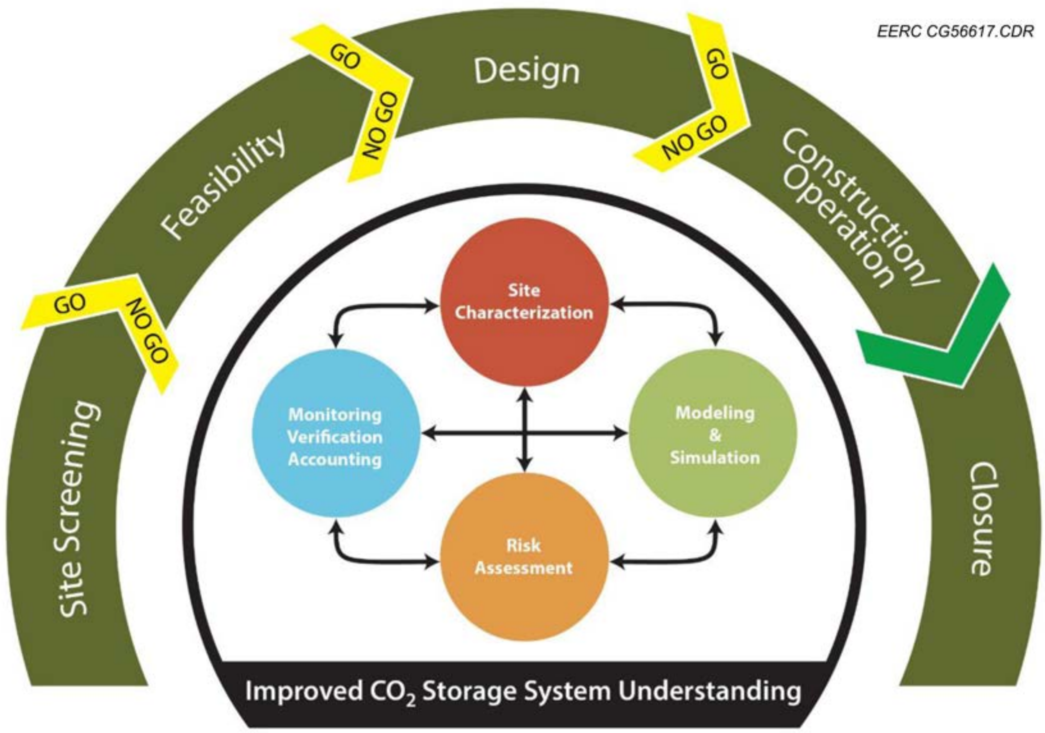

Figure 7. PCOR Partnership AMA for commercial development of CO_2 storage projects (Ayash and others, 2017).

Integral to the approach is a number of feedback loops, which permit the knowledge gained from each element to improve the overall understanding of the storage project, in turn informing the continued application of the other technical elements of the AMA. For example, knowledge gained through the MVA program may improve the static geologic model on which simulation and/or risk assessment predictions are partly based.

An important component of AMA implementation throughout PCOR Partnership activities is that a fit-for-purpose approach is ensured. Resources are focused on finding cost-effective solutions for key site-specific questions or issues. This approach recognizes that not all of the technical elements in Figure 6 may be required for each project and/or at every project phase, and that the level of detail to which they are performed during each phase can vary.

The remainder of this section expounds upon the four technical elements central to the PCOR Partnership AMA, including discussion and examples related to site characterization, modeling and simulation, risk assessment, and MVA.

3.3.2 Site Characterization

As one of the four AMA core technical elements, site characterization comprises collection, analysis, interpretation, and application of data and information of the critical properties and characteristics of the surface and subsurface environments relevant to the storage project. Site characterization activities directly aid the other AMA technical elements by providing the data and information that can be used as: 1) inputs to geologic models/simulations, 2) information to help discern the risk profile as part of a project's risk assessment, and/or 3) baseline data or guidance for baseline data collection in MVA. Site characterization activities are largely driven by project- and site-specific risk and uncertainty and the need to inform site design and operation. The fit-for-purpose approach allows for tailoring site characterization activities to address the needs of each unique storage project.

The overall goal of site characterization is to develop an understanding of surface and subsurface environments in order to assess factors that could influence project performance. However, the goals and reasons for performing site characterization activities are dynamic and change depending on the project site and operational phase. For instance, the goal of characterization activities during the site-screening phase is to identify—primarily on the basis of existing accessible data and information—one or more suitably located candidate storage sites that may offer sufficient storage capacity and the geologic structure necessary for safe, long-term containment of injected CO_2. Site characterization activities during the site-screening phase represent a first pass at collection, analysis, and interpretation of existing data sets that lay the foundation for additional investigation during subsequent project phases. In contrast, the goal of characterization activities during a primary feasibility and design phase is to establish the viability of any selected candidate project site(s) at a confidence level sufficient to support decisions on whether and how to proceed with the project. Assessing storage site viability in the feasibility phase is supported by acquiring the site characterization data needed to build a representative model of the site geology and surrounding environment. The geologic model is then used to conduct predictive simulations of CO_2 injection and storage and support risk assessments that provide an optimal understanding of critical factors, which include CO_2 storage capacity, CO_2

injectivity, and CO_2 containment. Glazewski and others (2017) provides a much more in-depth discussion of the different goals and methods of characterization activities during various storage project phases.

3.3.2.1 Application of Site Characterization to CO_2 Storage Complexes

PCOR Partnership Phase III site characterization activities were performed as part of the Bell Creek Integrated EOR and CO_2 Storage Project (hereafter referred to as "Bell Creek Project"). The field is located in southeastern Montana and is being developed in nine distinct phase areas, as shown in Figure 8. CO_2 injection began in May 2013. Currently, CO_2 injection has progressed in Phase Areas 1–5 of the field. At the end of commercial EOR operations, it is estimated that 12.7 Mt of CO_2 will be stored in the subsurface and 40 to 50 million incremental barrels of oil will be recovered. As of July 31, 2018, approximately 5.94 Mt of total gas (composition of approximately 98% CO_2) has been purchased and injected into the Bell Creek Field, equating to an estimated ***5.87 Mt of CO_2 stored***.

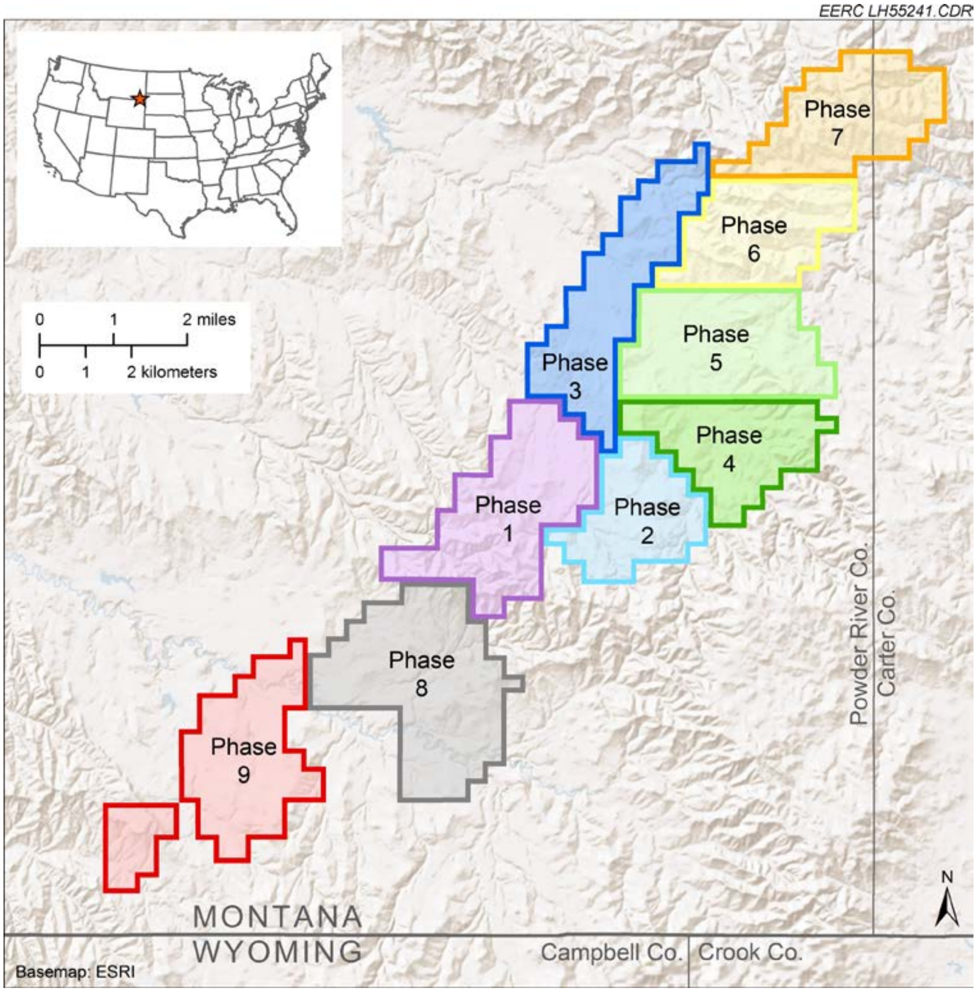

Figure 8. Bell Creek Project. Phase Areas 1–5 are currently under development (adapted from Wildgust and others, 2018).

The sandstone of the Lower Cretaceous Muddy Formation is the target for the Bell Creek Field. The overlying Mowry Formation provides the primary seal, preventing fluid migration to overlying aquifers and to the surface. On top of the Mowry Formation are several thousand feet of low-permeability shale formations, including the Belle Fourche, Greenhorn, Niobrara, and Pierre Formations, which provide redundant protection in the unlikely event that the primary seal fails to prevent upward fluid migration.

The historic geologic interpretation for the Muddy Formation of Bell Creek Field suggests that deposition occurred as part of a large, Galveston Island-style barrier bar along, at the time of deposition (Early Cretaceous), the eastern margin of the Cretaceous Interior Seaway (shoreline trending approximately northeast to southwest). This was interpreted by the lack of clean sand to the east (interpreted lagoonal deposits) and a general thickening of the Muddy sands to the west.

A detailed site characterization program provided a solid foundation for critical activities necessary to complete project objectives. Characterization activities performed in the field included core sample collection, well log acquisition, geochemical evaluations, geomechanical assessments, and geophysical investigations. These activities yielded essential and direct inputs into geocellular modeling activities to determine 1) CO_2 storage capacity of the target formation; 2) potential storage efficiency of the reservoir; and 3) mobility and fate of injected CO_2 for near-, intermediate-, and long-term time frames. Through the integration of these new data in modeling and simulation efforts, knowledge was generated which supported a very different understanding of the geologic processes through which the Muddy Formation reservoir was deposited, in contrast to decades of previous interpretations.

A baseline 3-D seismic survey was completed at the Bell Creek Project in 2012 and was interpreted after making well ties to identify the Bell Creek reservoir response. A seismic amplitude summation map, calculated as a summation of amplitudes within the Muddy Formation after a 90-degree phase shift was constructed (Burnison and others, 2014; Figure 8). Interpretation of the resulting amplitude map unveiled prominent geobody features contributing directly to reservoir heterogeneity. New understandings of the relationship between geobody regions and the architecture of observed geobodies (size and morphology) were used to revisit legacy data sets (well logs and core sample descriptions). Through this process, important knowledge was ultimately revealed indicating an alternative depositional model may be more plausible. This interpretation has been discussed previously in Bosshart and others (2015) and Jin and others (2016, 2017). Interpreted geobodies are shown in Figure 9, including an incised fluvial channel, a local barrier bar, a tidal channel complex, and others, as opposed to the previous interpretation of a Galveston island-type barrier.

The importance of these geologic learnings lies in better understanding the implications for preferential fluid flow and pressure response in the Muddy Formation reservoir as a result of CO_2 injection and oil production. This information was used to develop new geologic models for predictive simulations of CO_2 injection, which ultimately contributed to reducing technical uncertainty (and therefore risk) and technology deployment during MVA activities.

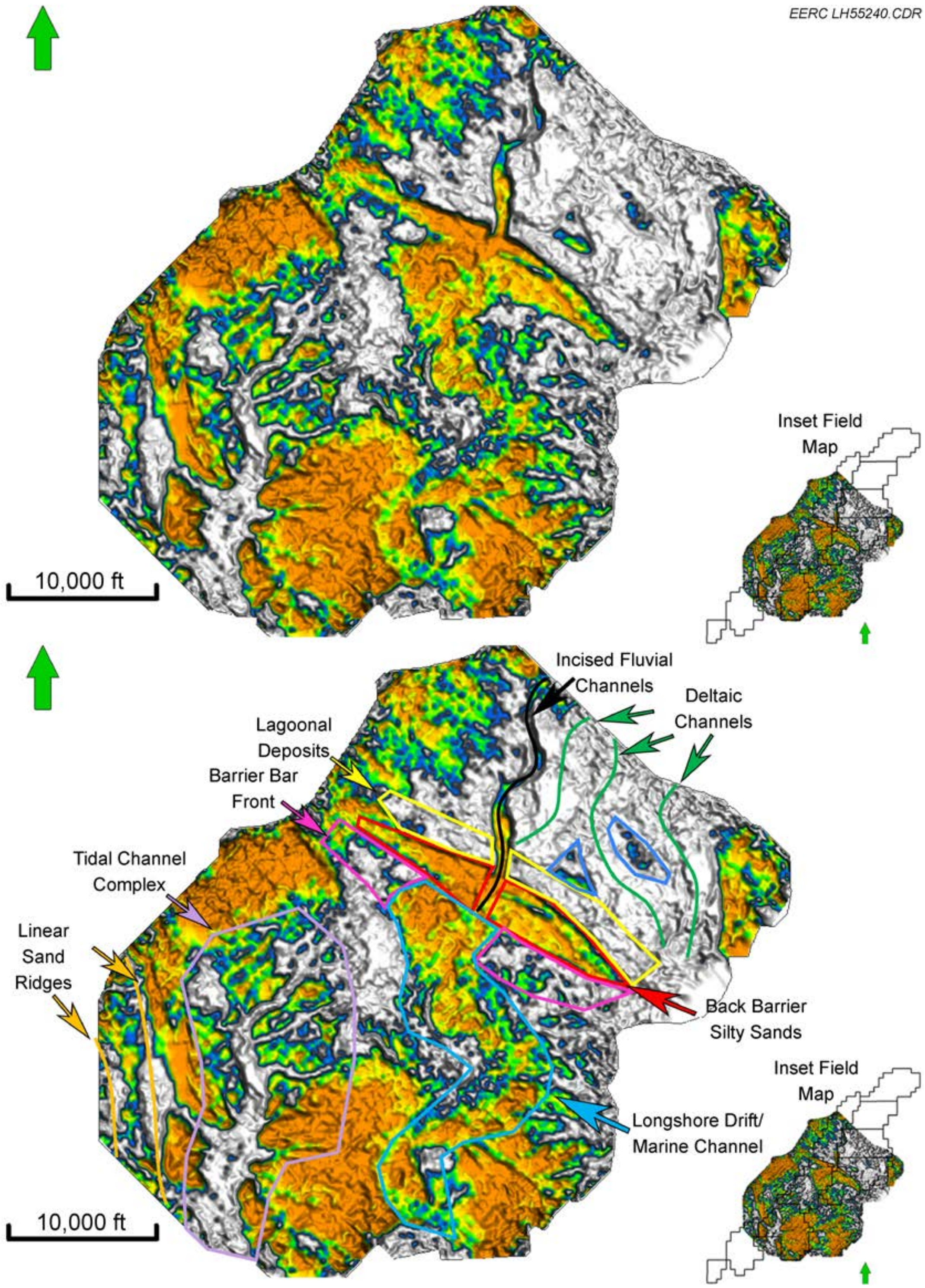

Figure 9. Amplitude summation map calculated over the Muddy Formation interval of the Bell Creek Field (top; adapted from Burnison and others, 2014) and an annotated version of the map identifying interpreted geobodies (bottom).

3.3.3 Modeling and Simulation

Modeling and simulation collectively comprise one of four technical elements of the AMA formalized by the PCOR Partnership for CO_2 storage project development. Modeling is defined here as the collation of subsurface data into a three-dimensional (3-D) representation of the subsurface geology and hydrogeology of a CO_2 storage site and surrounding area. Simulation refers to the process of using specialized software to create quantitative predictions of the dynamic effects of CO_2 injection, including one or more of the follow: migration of CO_2 and other formation fluids, pressure and temperature behavior, geochemical and geomechanical effects, and the long-term fate of injected CO_2 within the modeled volume. Modeling and simulation can be undertaken at a variety of scales, from regional to site-specific, and levels of complexity, and they should be developed according to the fit-for-purpose philosophy that is central to the AMA.

A typical geologic (or static) model being constructed to support simulation of injection will depict the storage reservoir formation(s) and confining zones (seals), together with structural features such as faults, fractures, and folds. The basis for model construction, invariably in digital form, is a combination of measured subsurface characteristics and geological interpretation. A general workflow for geologic model construction, designed to capture uncertainties, is widely understood among modeling professionals and is applicable to storage projects.

Simulation is the best tool available for supporting engineering judgment and decision-making processes such as technical and economic feasibility studies, optimization of operations, identifying subsurface risks, or development of effective MVA programs. A clear definition of objectives should be developed to frame simulations in support of overall storage project goals. The accuracy and reliability of simulation outputs depend heavily on the quality of input data, including the geologic model. An understanding of underlying uncertainties of available data and interpretations is essential to constrain simulation results.

Differences exist in conducting modeling and simulation activities for dedicated and associated storage scenarios. The availability of site-specific data for model construction is generally different for dedicated and associated CO_2 storage projects. Typically, a dedicated storage project targets a greenfield site, not previously used for commercial activities, for which there may be few or limited prior site-specific subsurface characterization data. In contrast, associated storage will likely occur in oil fields that have decades of production history; therefore, many aspects of the subsurface conditions of an associated CO_2 storage site are well characterized and will likely result in a significant amount of available data to support model development. In the case of associated CO_2 storage projects, established subsurface models likely already exist from prior oilfield development activities. In addition, operational data from the field's oil production allow the simulation model to be calibrated, or history-matched, to known performance data. History matching of existing injection/production well data (if available) is an important process for associated CO_2 storage scenarios. This process entails conducting numerical simulations of historical production/injection operations to achieve results that match well and/or field operational observations (e.g., production/injection rates and volumes, bottomhole pressures [BHP]). Key model parameters may be modified through this process to improve history matching, including permeability, fluid saturation, and relative permeability. With model parameters able to support simulations that closely match quality historical observations and data, increased accuracy is to be expected in further predictive forecasts. This process is generally followed in simulations of associated CO_2 storage, as CO_2 EOR is usually considered as a tertiary recovery operation (primary and secondary recovery data can be used in history matching).

3.3.3.1 Modeling and Simulation Examples from Bell Creek Field

The overarching goals for the PCOR Partnership modeling and simulation activities conducted in the Bell Creek Field include achieving predictions of fluid flow, pressure response, oil sweep, and CO_2 storage efficiency, and determining the long-term fate of injected CO_2.

Three generations of Bell Creek geologic models have been constructed by the EERC to provide the basis for numerical simulations to achieve the goals mentioned above. The first (V1) model encompassed an area slightly larger than the field's Phase Area 1 boundary. The second version (V2) attempted to expand the geologic model area of review to encompass the entire field and a large portion of the surrounding area (some 200 square miles). Both the V1 and V2 models were developed based on the historic depositional model that the Muddy sands were deposited as part of a large, Galveston Island-style barrier. Facies and petrophysical property distributions for the V1 and V2 reservoir models were achieved reflecting anisotropy trends consistent with such a large-scale barrier bar oriented northeast–southwest. As such, modeled property trends exhibited greater connectivity parallel to the strike of the interpreted barrier bar (northeast–southwest).

These models were used to run history-matching and numerical simulation efforts. There were substantial difficulties in the history-matching process, including adjustment of fluid flow boundaries; adjustment of near-wellbore fluid saturations, porosity, and permeability values; and the necessity of additional pseudowells for pressure support to achieve acceptable history-matched conditions. These difficulties indicated that the reservoir geology had not been captured accurately in the previous modeling efforts. These issues spurred renewed efforts to understand the deposition of the Muddy Formation sands of the Bell Creek Field and the development of a new (V3) geologic model. This model incorporated important differences in approach and geological understanding, much of which was enabled by the incorporation of learnings from newly acquired 3-D surface seismic data, as described previously in the Site Characterization section above (see Figure 9). The seismic data were used to parse the reservoir into individual geobody regions, each region having an individual set of facies and petrophysical property distributions to better capture reservoir heterogeneity (Figure 10).

After integrating the new understanding of heterogeneity in the V3 geologic model, history matching was conducted with greater success than in the case of previous models, suggesting that rock properties were captured more accurately through the revision process. Subsequent predictive simulations were conducted for a variety of purposes, including 1) evaluating the movement and disposition of injected CO_2 during both water-alternating-gas (WAG) and continuous CO_2 injection (CCI) operational schedule, 2) estimating the oil production response to both WAG and CCI operational schedules, 3) determining the impact of impurities on recycled gas EOR and CO_2 storage performance, and 4) investigating long-term CO_2 migration behavior. The results of these investigations, as well as the results from the V1 and V2 Bell Creek geologic models, are detailed in previously submitted Deliverable (D) 66 reports (Pu and others, 2011; Saini and others, 2012; Gorecki and others, 2013; Liu and others, 2014; Bosshart and others, 2015; Jin and others, 2016; Peterson and others, 2017).

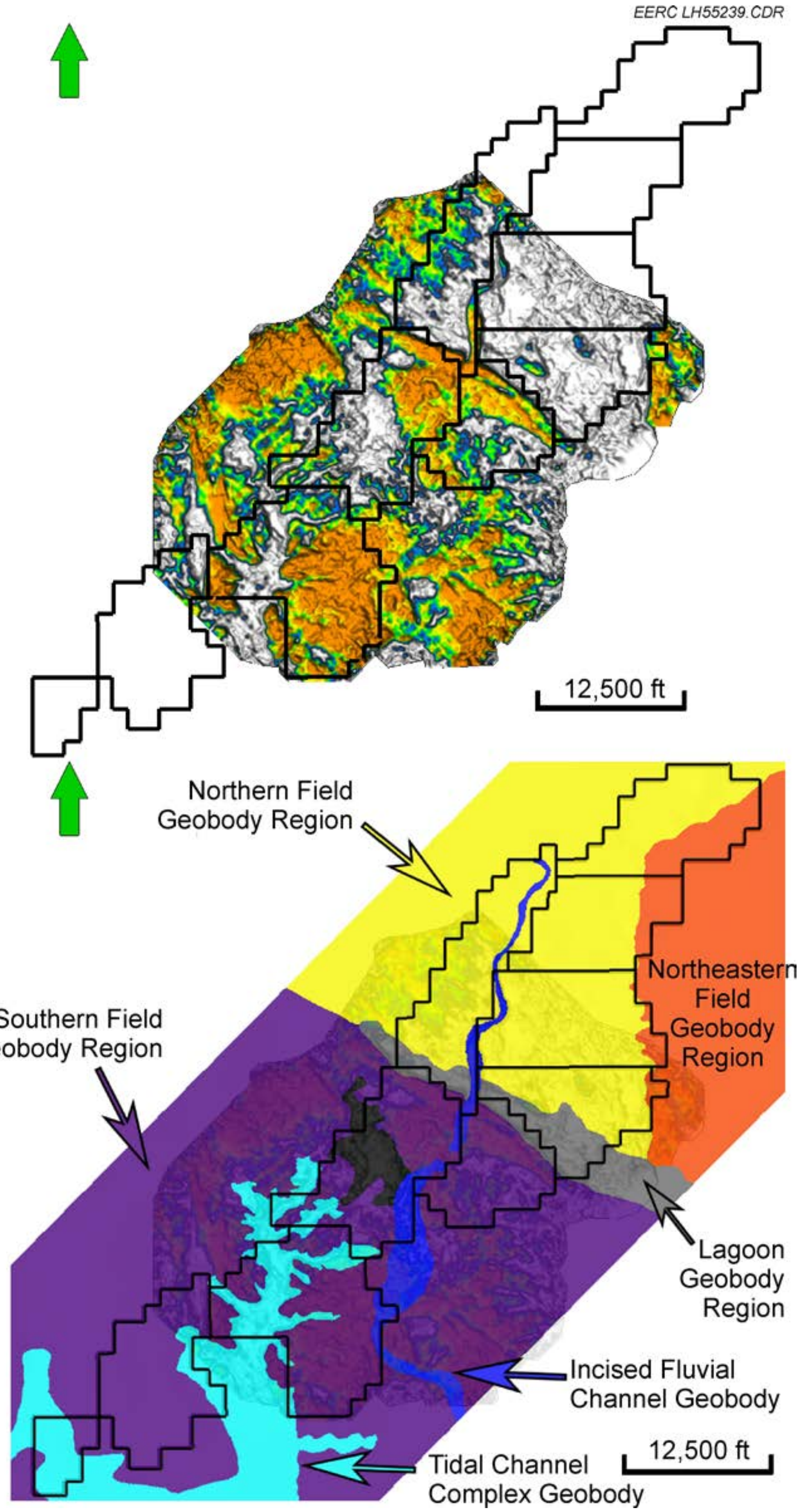

Figure 10. Amplitude summation map calculated over the Muddy Formation interval of the Bell Creek Field (top; adapted from Burnison and others, 2014) and a semitransparent geobody region overlay with the amplitude map (bottom).

With the experience gained in the context of the PCOR Partnership's Bell Creek Field efforts, important high-level conclusions from modeling and simulation investigations include the following:

1. Modern characterization data (i.e., 3-D surface seismic data) may provide key learnings needed to construct models able to accurately predict phenomena accompanying, and resulting from, CO_2 injection.

2. Model development should be an iterative process. Simulation results and information generated in other technical areas of a project may provide indications that model adjustment may be required and may assist in determining where model uncertainty resides.

3. Referring back to the PCOR Partnership AMA, the interconnected nature of the four technical elements upon which the approach is focused (the other elements being site characterization, risk assessment, and MVA) is apparent when conducting modeling and simulation activities. Through this process, new information brought forth by any of these four technical elements can be used to enhance the others, contributing positively to the potential for success over the course of a CO_2 storage project. For example:

    a. Characterization data provide the basis for geologic model construction. Through initial model construction and numerical simulation activities, key subsurface data gaps are often identified, enabling future targeted data acquisition for geologic characterization to reduce technical uncertainty.

    b. Technical uncertainty translates to risk. Identified risks can guide further simulation activities accounting for a range of possible scenarios with the desired confidence intervals (i.e., uncertainty analyses resulting in P_{10} [10th percentile], P_{50} [50th percentile], and P_{90} [90th percentile] property distributions) to investigate the likelihood and impact of specific risks.

    c. Simulation of the reservoir and/or shallow subsurface aquifers produces results needed to optimize the deployment of monitoring technology.

    d. Operational monitoring data can be used to history-match numerical simulations for increased accuracy in further predictive estimates of fluid flow, pressure, geochemical, and/or geomechanical response.

3.3.4 Risk Assessment

Subsurface technical risk assessments were undertaken as part of the Phase III demonstration projects, one of which was conducted as part of a feasibility study for the dedicated storage of CO_2 in a saline formation (Fort Nelson project) and another which involved associated CO_2 storage incidental to EOR at a commercial CO_2 EOR facility (Bell Creek project). In both cases, the CO_2 storage project contains a subsurface storage complex and a storage site. A subsurface storage complex refers to the subsurface storage unit and seal formation(s) extending laterally to the defined limits of the CO_2 storage operation, and the storage site refers to an area of the ground surface where CO_2 injection facilities are developed and storage activities, including monitoring, take place (Canadian Standards Association, 2012). The efforts of the PCOR Partnership have focused on the technical risks associated with the subsurface storage complex; however, the risk assessment process that was used is applicable to the storage site as well.

3.3.4.1 Standardized Risk Management Framework

Figure 10 illustrates the overarching risk management process used by the PCOR Partnership for managing the subsurface technical risks of a CO_2 storage project. This process is consistent with ISO 31000, an international standard for risk management (International Organization for Standardization, 2009).

The PCOR Partnership used a risk management framework that complies with the International Standards Organization (ISO) recommendations for risk management (Figure 11). This risk management framework comprises five primary elements: 1) establish the context, 2) risk assessment, 3) risk treatment, 4) communication, and 5) monitoring. Establishing the context generally consists of defining the scope of the risk management framework and outlining the risk criteria that will be used to evaluate the individual project risks. **Risk assessment** refers to the overall process comprising three components: risk identification, risk analysis, and risk evaluation (blue box in Figure 11). **Risk identification** entails identifying the relevant site-specific technical risks and compiling those risks into a project risk register. **Risk analysis** involves quantifying, or scoring, the risks in the risk register by estimating their **likelihood** (i.e., the probability that the risk may occur) and their **impact** on a number of different project attributes should the risk occur (e.g., cost, time/schedule, scope, and quality). Lastly, **risk evaluation** uses the probability and impact scores for each individual risk to rank and classify the risks from lower- to higher-ranking.

While the risk management framework shown in Figure 11 represents a standardized practice for implementing the risk management process, several unique characteristics of CO_2 storage projects influence the application of this process. The PCOR Partnership has focused on identifying these unique features for two elements of this process: establishing the context for a CO_2 storage project risk assessment and conducting the risk assessment through risk identification, analysis, and evaluation.

3.3.4.2 Key Differences Between Conducting Risk Assessments at Dedicated and Associated Storage Projects

Some of the key differences between dedicated and associated CO_2 storage projects that can affect risk assessment include data availability, potential leakage pathways, and regulatory environment. The availability of site-specific data to inform the risk assessment process is generally different for dedicated and associated CO_2 storage projects. Typically, dedicated storage projects lack prior site-specific subsurface characterization data, whereas associated storage projects generally have a portfolio of information available from previous characterization efforts and oil production history. Therefore, many aspects of the subsurface conditions of an associated storage site are likely well known, with a significant amount of data available to support the risk assessment process.

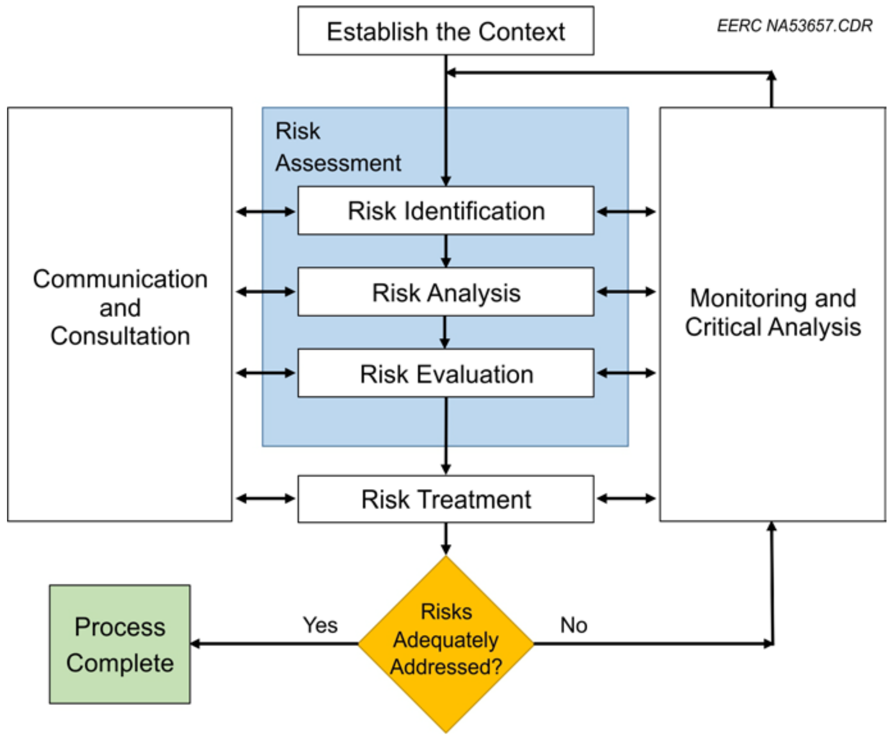

Figure 11. Risk management process adapted from the ISO 31000 (2009) standard.

The potential leakage of the stored CO_2 from the storage complex into overlying domains of concern (e.g., underground sources of drinking water [USDW], surface waters, atmosphere) represents a risk common to all storage projects. However, the likely causes of leakage may differ between dedicated and associated storage projects. For example, associated storage sites will likely have numerous existing wellbores that penetrate the geologic strata from the surface into the storage unit; therefore, poor wellbore integrity represents a primary potential leakage pathway. At the same time, the presence of oil and gas production at the associated storage site suggests that the primary seal, or cap rock, overlying the storage unit is capable of containing fluids under pressure over geologic time. In contrast, wellbore integrity may be less of a concern at a dedicated storage site because of a lack of preexisting wellbore penetrations through the storage complex. Instead, a primary concern for potential leakage may be the integrity of the primary seal, which generally has no proven history of trapping buoyant fluids like hydrocarbons.

Lastly, the regulatory regime and corresponding required monitoring activities for associated storage projects are different in scope than those for dedicated storage projects, resulting in different types and quantities of data available to inform updates to the risk assessment.

3.3.4.3 Example Risk Assessment: Dedicated Storage (Fort Nelson Project)

The Fort Nelson sour gas-processing plant, which is the largest in North America, is located in northeastern British Columbia. In anticipation of a large expansion of the facility and the continued evolution of GHG regulations by both local and federal governments, the plant operator, Spectra Energy, proactively explored the feasibility of including CCS technology as part of the plant expansion. The proposed CCS operations consisted of capturing sour CO_2 separated by gas processing and storing it in a DSF. The application CCS technology would allow Spectra Energy to expand its gas-processing operations without a commensurate increase in CO_2 emissions.

The PCOR Partnership conducted a risk assessment for the Fort Nelson Project focused on potential subsurface technical risks associated with the proposed operations (see Appendix 4 for more information about the Fort Nelson Project). Results of the risk assessments were presented in the form of risk maps. Some examples of these risk maps are shown in Figure 12. These risk maps plot the expected values of the probability score for CO_2 containment-related risks (y-axis) against the expected value of an impact score, should the risk occur, on key project attributes including cost, time/schedule, scope, and quality. Two risk assessments were performed for the Fort Nelson Project, each associated with a different potential CO_2 injection location – an original test well location (left panel in Figure 12) and an alternate well location (right panel in Figure 12). The alternate location was examined to address a specific risk that was associated with the original injection location (i.e., interference with adjacent commercial gas pools) and which ranked very high in terms of both probability of occurrence and potential impact to the project. The color scheme for the risk maps indicates the following:

1. Green: low risk– No immediate action required, continue to monitor.
2. Yellow: transition – Gather more data to reduce uncertainty; treat risk whenever possible or affordable.
3. Orange: moderate risk – Treat risk in the short- to midterm.
4. Red: high risk – Immediately treat risk in the short-term.

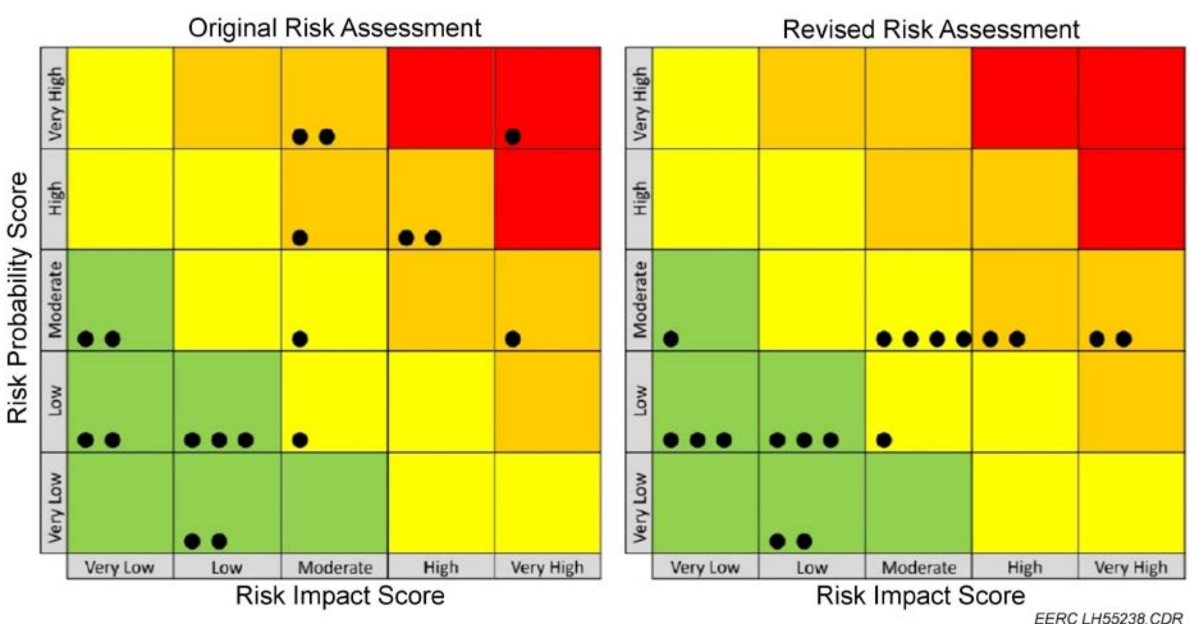

Figure 12. Risk maps showing the assessed values of probability and impact scores for CO_2 containment-related risks associated with an original injection well location (original risk assessment; left panel) and an alternate injection well location (revised risk assessment; right panel) (adapted from Azzolina and others, 2017).

In this example, the qualitative risk maps show the expected values of risk probability and impact scores for the CO_2 containment-related risks associated with the two risk tracks that were examined. The higher-ranking risks (i.e., moderate [orange] and high [red]) associated with the original test well location (right panel in Figure 11) relate to subsurface pressure changes and lateral CO_2 migration affecting neighboring natural gas pools prior to the end of their commercial life. To address these high-ranking risks, which required some form of immediate action, the planned CO_2 injection well was relocated to an alternate location 5 km west of the originally proposed location. In doing so, the scores of the high-ranking risks were significantly reduced to acceptable levels. At the same time, the probability of all remaining risks was ranked as moderate, low, or very low (right panel in Figure 12).

A probabilistic analysis using Monte Carlo simulations was applied in the Fort Nelson risk assessments to capture a statistical range of the total project risk profiles. Figure 13 presents histograms of the simulated outcomes for the total project risk. These histograms illustrate that the total project risk profile for the alternate CO_2 injection location is significantly lower than that for the original test well location (i.e., the risk profile shifted to the left, representing a lower risk profile). In other words, moving the CO_2 injection location approximately 5 km west of the original location significantly reduced the overall project risk because it lowered the probability and potential impacts of the CO_2 containment-related risks.

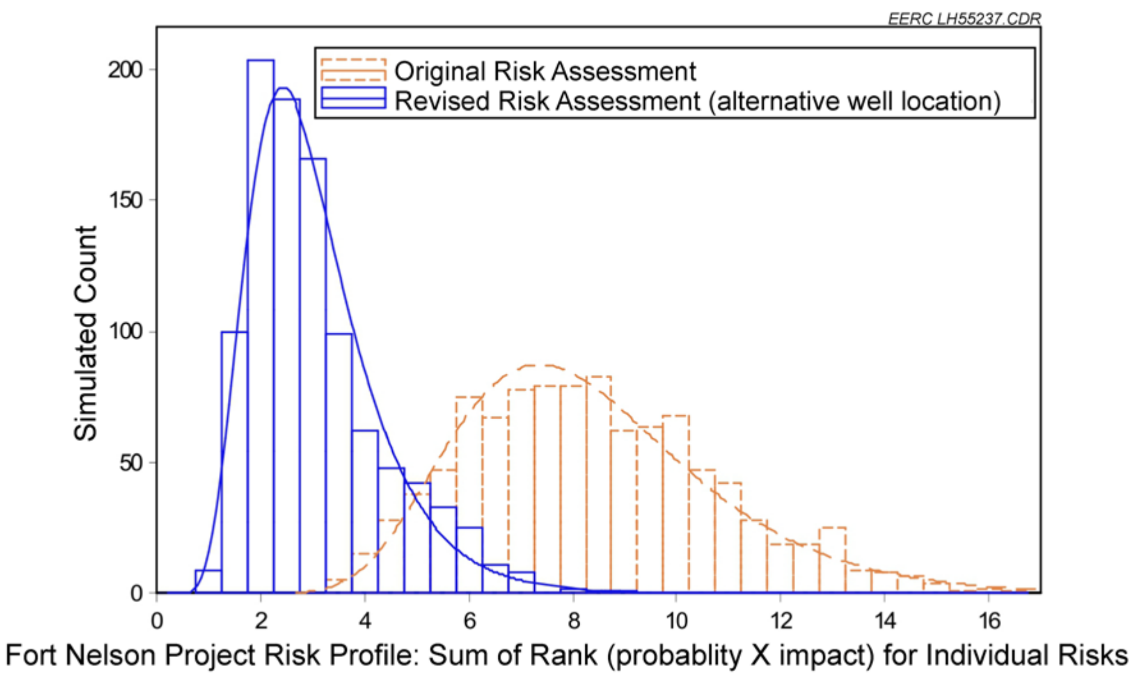

Figure 13. Histograms and fitted statistical distributions for the total risk profile of the Fort Nelson project. Original planned well location (orange bars) versus the alternate well location (blue bars) (adapted from Azzolina and others, 2017).

3.3.4.4 Example Risk Assessment: Associated Storage (Bell Creek Project)

The Bell Creek field demonstration test evaluated the potential for associated geological storage of CO_2 during CO_2 EOR in an oil field in Bell Creek, Montana (see Appendix 4 for more information). CO_2 injection at the site was initiated in May 2013, with CO_2 initially obtained from the ConocoPhillips' Lost Cabin natural gas-processing plant in central Wyoming. This CO_2 source was later supplemented with, and eventually replaced by, CO_2 from the Shute Creek natural gas-processing plant of ExxonMobil, which is located in Green River, Wyoming. A supply of approximately 50 million cubic feet of CO_2 per day is delivered to the site and is injected through multiple wells into a sandstone reservoir at a depth of approximately 4500 ft (1372 m). The EOR activities at Bell Creek will store an estimated 1.1 Mt of CO_2 annually.

Bell Creek risk assessments were conducted in 2012 (1 year prior to CO_2 injection) and again in 2014 and 2016 (1 and 3 years following the initiation of CO_2 injection, respectively). The focus of these risk assessments was on the associated CO_2 storage incidental to the EOR operations, not on the oil production or EOR operations. Probability and impact scores were determined for the individual technical risks, which were then ranked using the sum of the probability score and the risk impact score. Figure 14 presents these risk scores over time (i.e., 2012 to 2016) as determined for the technical risks of CO_2 storage capacity, CO_2 injectivity, and CO_2 retention and the project impacts of cost, time/schedule, scope, and quality. Using this approach, a relative ranking of the Bell Creek risks was possible, solely for the purposes of comparing and contrasting the different storage project risks over time. It is important to note that the absolute value of the average risk score cannot be extrapolated to other sites or other risk assessments.

Figure 14 illustrates the change in the average risk score from 2012 to 2016 for the group of risks involving CO_2 storage capacity, injectivity, and retention and the risk impacts of cost, time/schedule, scope, and quality. For all risk groupings, there is a downward trend (reduction) in the average risk score over time, reflecting lower overall average risk probability and/or risk impact scores for the Bell Creek risk assessment. Equally important, the uncertainty of the average risk score for any given year (i.e., vertical spread on Figure 14) also was dramatically reduced between 2014 and 2016. These observed changes are a direct result of two facts. First, they reflect the increase in site knowledge occurring over time as the project advanced, with the first risk assessment prior to any CO_2 injection and the latter two risk assessments occurring 1 and 3 years, respectively, after the initiation of CO_2 injection. As knowledge of the site increased by collecting operational and monitoring data, the likelihood for many of the storage project risks was reduced, thereby lowering the average risk score of the project.

Important results of risk assessments for the dedicated CO_2 storage project at Fort Nelson, British Columbia, Canada, and the associated storage project at the CO_2 EOR facility in Bell Creek, Montana, are included below. The key messages portrayed by these two examples are as follows:

- Risk maps (Fort Nelson example, Figure 12) are valuable tools for visually evaluating the quantitative results of risk analysis by plotting the risk probability score on the y-axis and risk impact score on the x-axis for each individual risk.

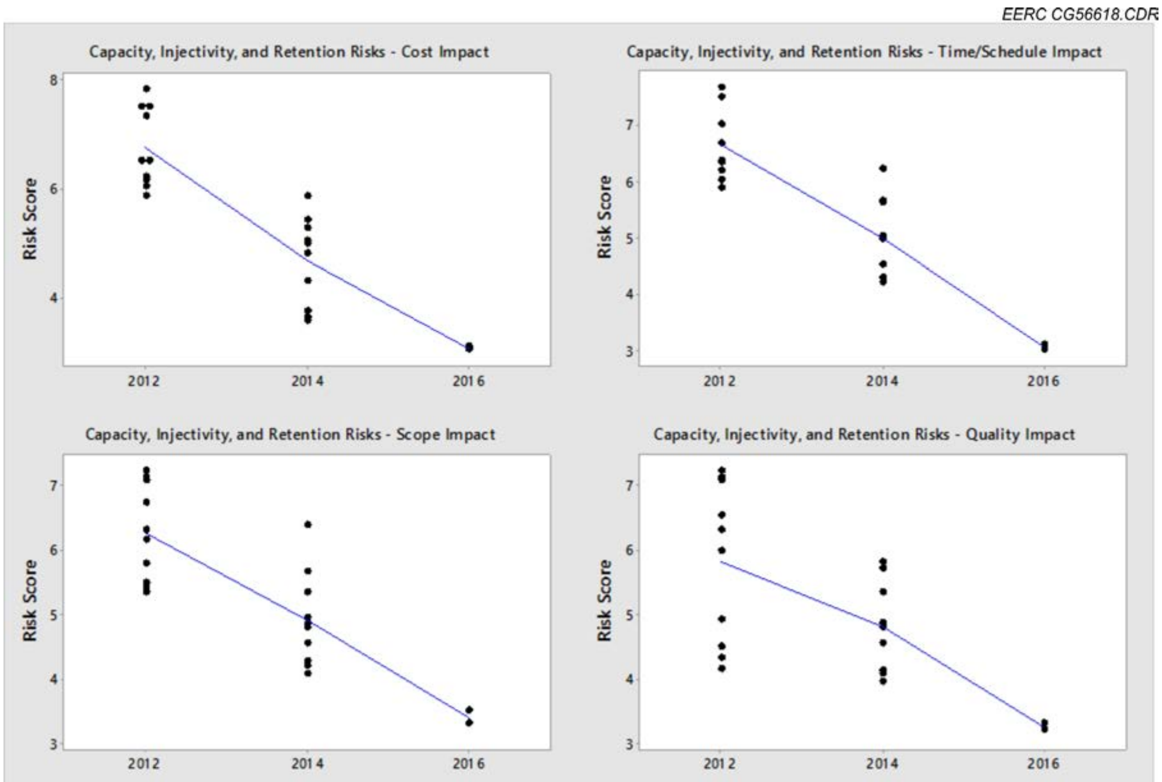

Figure 14. Risk scores evaluated over time (years 2012 to 2016) for Bell Creek risks related to CO_2 storage capacity, injectivity, and retention for impacts to cost (upper left), time/schedule (upper right), scope (lower left), and quality (lower right). A horizontal "jitter" has been added to the *x*-direction for points with similar risk scores (for data points with identical risk scores, they are separated by a small horizontal distance, or jitter, so that they are visible).

- Probabilistic analyses using Monte Carlo simulations (Fort Nelson example, Figure 13) may be applied to capture and monitor the risk profiles for various project development plans as well as the change in project risk profiles over time.

- An assessment of the project risks will evolve over time (Bell Creek Project example, Figure 14). Many risks will decrease with the reduction of uncertainty as new data are generated, analyzed, and integrated. Revisiting risk assessment over the life of a project will help guide future data acquisition activities, operational strategies, monitoring technology deployment, and communication with stakeholders.

- The majority of the subsurface technical risks associated with these two PCOR Partnership examples did not exceed any threshold criteria and in only one instance was a risk ranked high enough to require immediate attention (see Fort Nelson Project example above). Specifically, the potential for the injected CO_2 to impact adjacent commercial gas pools in Fort Nelson was a potential risk that was ranked as high, requiring immediate short-term treatment (i.e., the relocation of the CO_2 injection well).

The risk assessment process was able to identify this risk in the early stages of the project life cycle (i.e., during the feasibility study), leaving adequate time for the execution of design changes in the CO_2 injection plan (i.e., moving the location of the CO_2 injection well 5 km away from the original site) that reduced the risk to acceptable levels.

3.3.5 Monitoring, Verification, and Accounting

MVA is the fourth activity central to the PCOR Partnership's AMA. The PCOR Partnership has demonstrated that the geologic storage of CO_2 can be effectively monitored to provide assurance that subsurface storage operations are safe and do not adversely impact the environment and other resources. Monitoring may be accomplished using a variety of currently available technologies, supplemented by innovative techniques that are currently being investigated and demonstrated by DOE, and is equally effective for both dedicated storage projects (typically in DSFs) and associated storage projects (most commonly resulting from CO_2 EOR). The unique geologic setting and characteristics of individual storage sites will require the development of a site-specific MVA approach. In all cases, monitoring objectives should be defined based on overall project goals (e.g., the quantity of CO_2 to be stored, absence of impacts on other resources and the environment), prioritized subsurface technical risks, and site-specific regulatory requirements.

3.3.5.1 Candidate Monitoring Technologies

A MVA program was implemented at the Bell Creek Field. The surface, near-surface, and deep subsurface monitoring techniques in the Bell Creek Field were evaluated based on their ability to efficiently and effectively monitor the subsurface technical parameters of concern, as guided/informed by risk assessments conducted at the site. MVA data can also be used to aid the management of the storage operations by allowing the site operator to maintain injection rates and pressures to achieve optimum efficiency while still operating within the safe limits of the reservoir. The MVA approach developed for the Bell Creek Project was guided by the site characterization, modeling, simulation, and risk assessment efforts, building upon the data routinely generated by field operations while minimizing any interference with ongoing oil recovery. Also worth noting, the number and type of monitoring technologies deployed as part of the Bell Creek Project are indicative of the research nature of the effort. Government funding supported this effort to investigate the technical feasibility of monitoring CO_2 in the subsurface using a number of techniques. The deployment of commercial MVA programs will be able to take advantage of these research results to select an optimal suite of monitoring technologies that will provide a more focused and cost-effective monitoring strategy.

Combinations of monitoring techniques were used to create a baseline data set (i.e., prior to CO_2 injection) and continued to be used to generate operational (i.e., during CO_2 injection) monitoring data sets, which were being integrated with technical risk assessment and modeling and simulation activities in accordance with the AMA of the PCOR Partnership. Figure 15 illustrates the stratigraphy present in the Bell Creek Field, the various monitoring techniques applied, and the approximate depths each technique covers.

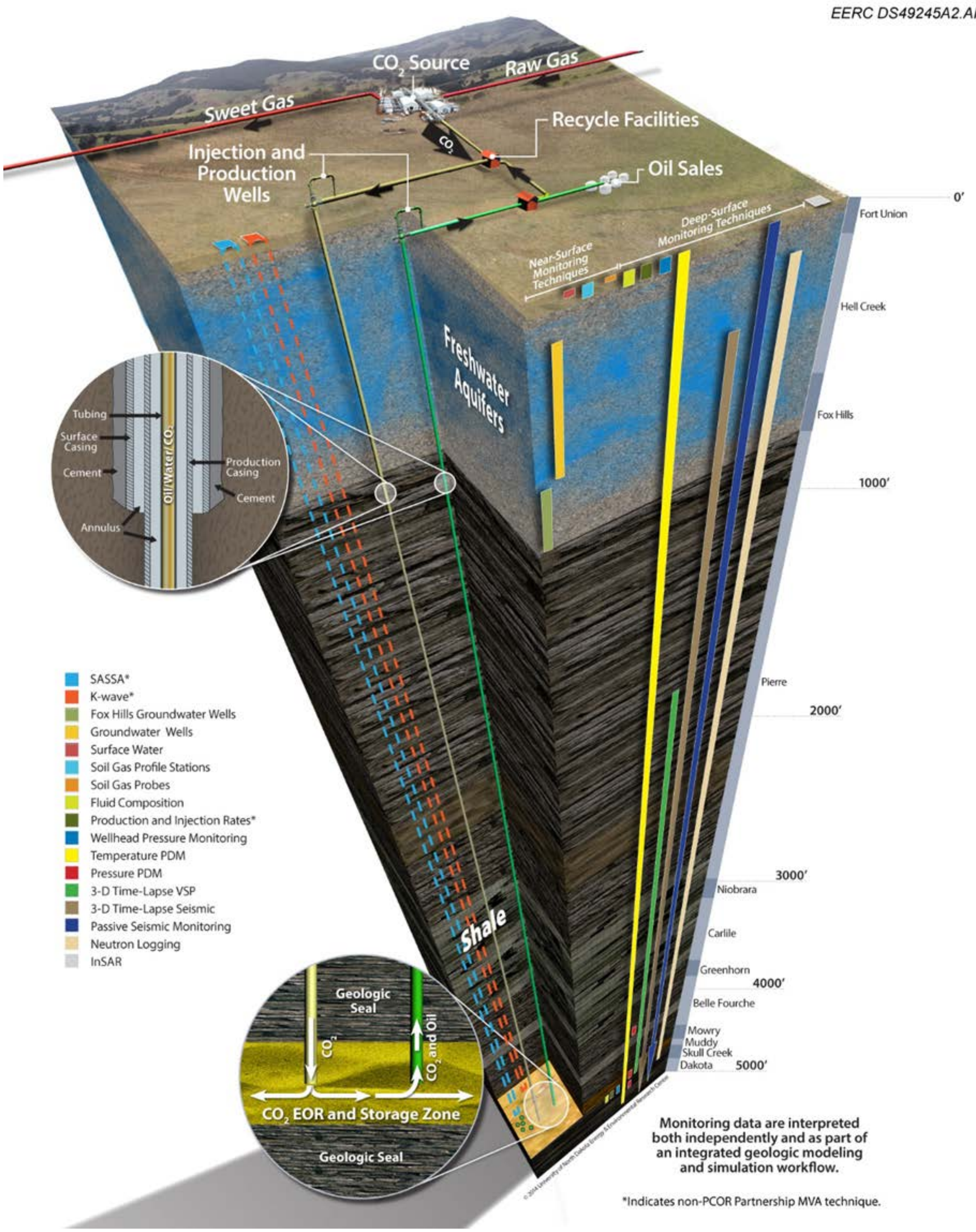

Figure 15. Stratigraphic column of the Bell Creek Field illustrating individual MVA techniques applied as part of the Bell Creek Project (modified from Hamling, 2013).

Deep subsurface monitoring is used to demonstrate that CO_2 is securely contained within the reservoir and storage complex, and to calibrate predictive simulations through history matching. Tested and proven data collection methods for establishing deep subsurface baselines include seismic surveys, pulsed-neutron and other well-logging techniques, pressure/temperature measurements, analysis of core samples and reservoir fluids, and analysis of existing nearby injection and production operations. With establishment of accurate baseline conditions in the deep subsurface, the subsequent migration and behavior of the injected CO_2 in the operational phase can be effectively monitored with the same or a similar range of technologies. Post-closure monitoring is intended to demonstrate the long-term security and low-risk profile of a storage site, in agreement with history-matched predictive simulations.

Shallow and surface-monitoring technologies applied at the Bell Creek Field included soil gas probes, soil gas profile stations, and fluid sampling of surface water sources and shallow groundwater wells. An important distinction between deep subsurface and shallow/surface environments is that deeper environments are relatively stable, whereas shallow/surface environments are subject to climate- and weather-driven variability. This often means that the establishment of accurate baselines usually requires a range of seasonal measurements, which may require shallow/surface monitoring to start several years prior to the initiation of CO_2 injection. The importance of monitoring shallow/surface environments is largely focused on generating information, which may be required to provide further assurance to stakeholders/regulators, and provides a warning system in the unlikely event of a significant leak. The absence of any evidence of leakage can build confidence during monitoring of the operational phase, with the potential to decrease costs through reduced survey locations and frequency. Baseline and operational measurements may also be used to identify key parameters and streamline environmental monitoring programs.

3.3.5.2 Selected Examples of MVA Accomplishments

Using the monitoring technologies discussed above, a large amount of MVA data were collected as part of the Bell Creek Project. A number of important observations were made through the interpretation of these MVA data and have been previously reported in Glazewski and others (2018). One of the more illustrative examples of these interpretations and their contribution to developing an improved understanding of the CO_2 behavior in the subsurface is provided in an examination of a 4-D seismic investigation.

3.3.5.3 4-D Seismic Investigation

As discussed previously in the Site Characterization and Modeling and Simulation sections, important learnings were generated from a baseline 3-D surface seismic survey acquired in the Bell Creek Field in 2012. This data set revealed interwell heterogeneity and flow boundaries at certain locations within the field. The continuity and dimensions were shown for:

1. An incised fluvial channel in the northern part of the field that acts as a flow boundary along the eastern margin of Phase Area 3 and between Phase Areas 1 and 2.

2. Lagoonal deposits, associated with a local barrier bar trending generally northwest–southeast, that serve as a flow boundary between Phase Areas 1 and 3 and between Phase Areas 2 and 4.

3. A tidal channel complex near the southern end of the field.

However, interpretation of the baseline 3-D seismic survey was ambiguous at some locations, such as the precise location of a suspected permeability barrier due to a fluvial channel incision along the boundary between Phase Areas 1 and 2. At this particular location, the seismic expression of the incised fluvial channel was masked by surrounding deposits with similar amplitude response. Figure 16 shows an interpreted amplitude summation map, calculated over the Muddy Formation interval of the field, with prominent geobodies and a polygon approximating the extent of a 4-D seismic investigation.

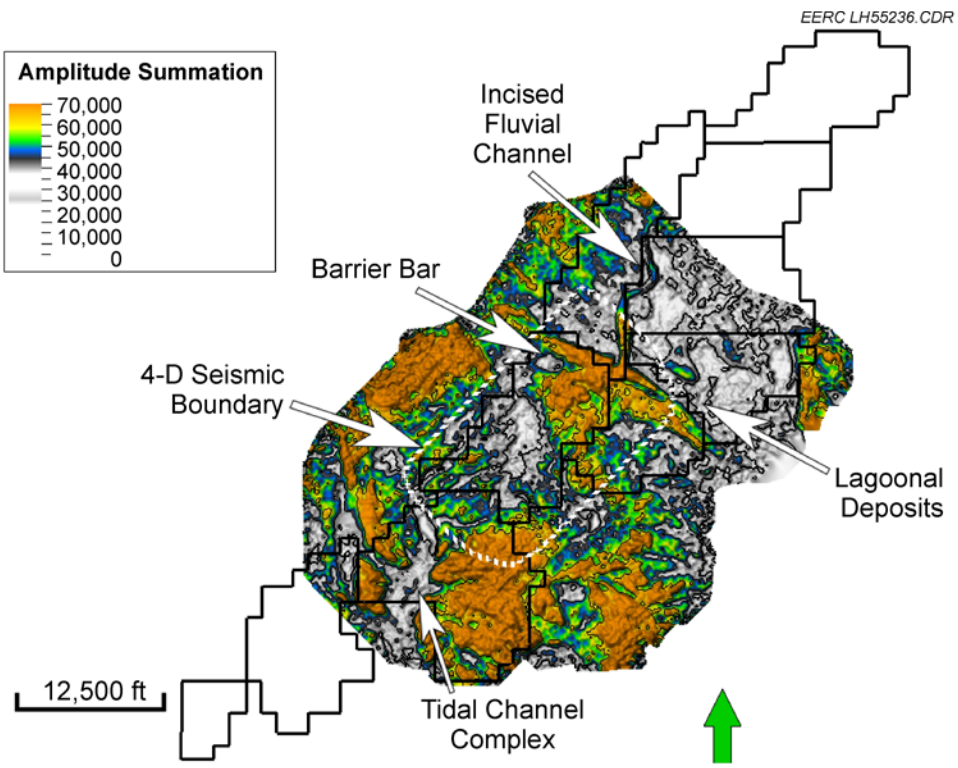

Figure 16. Interpreted amplitude summation map, calculated over the Muddy Formation interval of the Bell Creek Field, with prominent geobodies and a polygon approximating the extent of a 4-D seismic investigation (see Figure 17). Notable in this image is the apparent truncation of the incised fluvial channel near the intersection of the Phase Areas 1, 2, 3, and 4.

This baseline survey was followed by a repeat 3-D surface seismic survey, acquired in 2014 following the injection of 1.2 Mt of CO_2. A time-lapse (4-D) seismic investigation was conducted using the baseline survey (2012) and the repeat survey, which enabled visualization of the combined effects of changes in CO_2 saturation and pressure resulting from injection in the first two phase areas of the Bell Creek Field (Figure 17). Reservoir heterogeneity was clearly illustrated, including a set of prominent intersecting permeability barriers (shaly lagoonal deposits, oriented northwest–southeast, associated with a barrier bar to the southwest, and a shale-filled incised fluvial channel, oriented generally north–south). These features impeded fluid flow and pressure dissipation and, therefore, exhibited little identifiable change from the baseline survey to the repeat survey. A hydraulic link across the shale-filled incised fluvial channel was also observed, connecting Phase Area 1 and Phase Area 2 (allowing fluid and pressure communication between these two phase areas). Also, CO_2 in Phase Area 1 was observed migrating slowly updip (to the east) and banking against the closure formed by the incised channel permeability barrier. Lastly, a greater 4-D amplitude difference was observed in the Phase Area 2 in comparison to Phase Area 1, although the amount of injected CO_2 was less. The greater amplitude response was due to greater pressure change between baseline and repeat surveys.

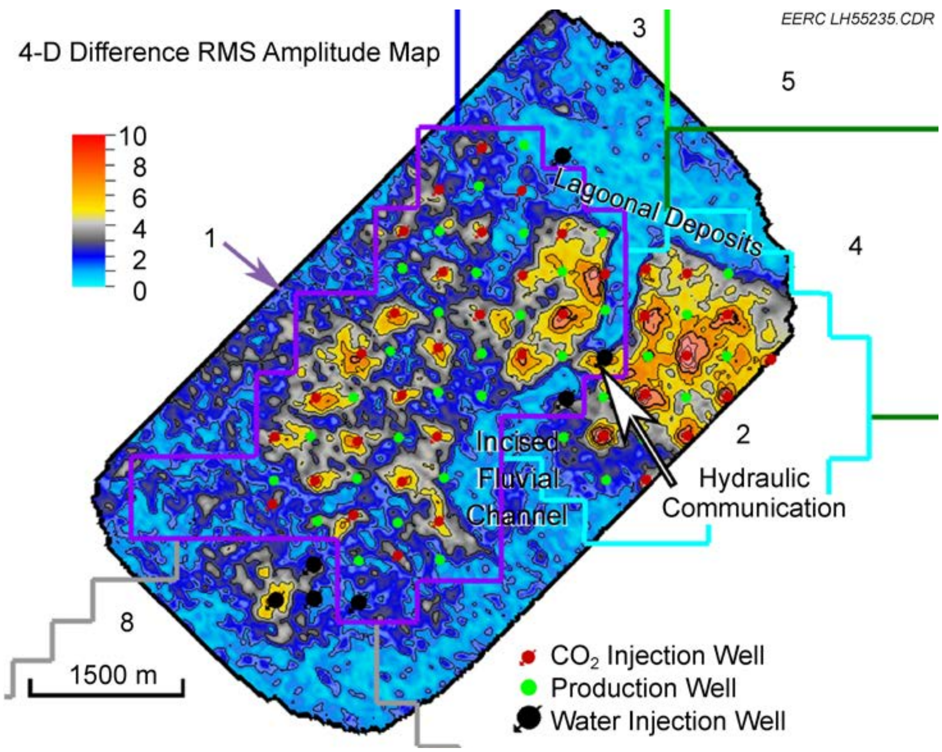

Figure 17. Interpretation of the first 4-D seismic investigation (2012 versus 2014) showing root-mean-square amplitude over the Muddy Formation interval (modified from Burnison and others, 2017). Red dots with arrows indicate injection wells, green dots are producing wells, and black dots with arrows represent water injection wells. The field's development phases are labeled 1–5 and 8. Cooler colors indicate areas with little change in CO_2 saturation or pressure, while warmer colors indicate areas affected with relatively greater change in CO_2 saturation or pressure from 2012 to 2014.

4.0 ASSOCIATED STORAGE AND LIFE CYCLE ANALYSIS

4.1 Relationship Between Quantities of Purchased, Recycled, and Stored CO_2

As CO_2 injection (or flooding of the reservoir) in an EOR operation progresses, increasing quantities of CO_2 in the reservoir migrate from injection wells to producing wells. After breakthrough of migrating CO_2 at production wells, produced oil is mixed with previously injected CO_2 and the proportion of this CO_2 increases with time as flooding progresses. The operator could choose to vent the CO_2 once stripped from the produced oil; however, CO_2 represents a valuable commodity and a recycling system is invariably employed to collect, dry, and reinject the produced CO_2 back into the reservoir (Figure 18).

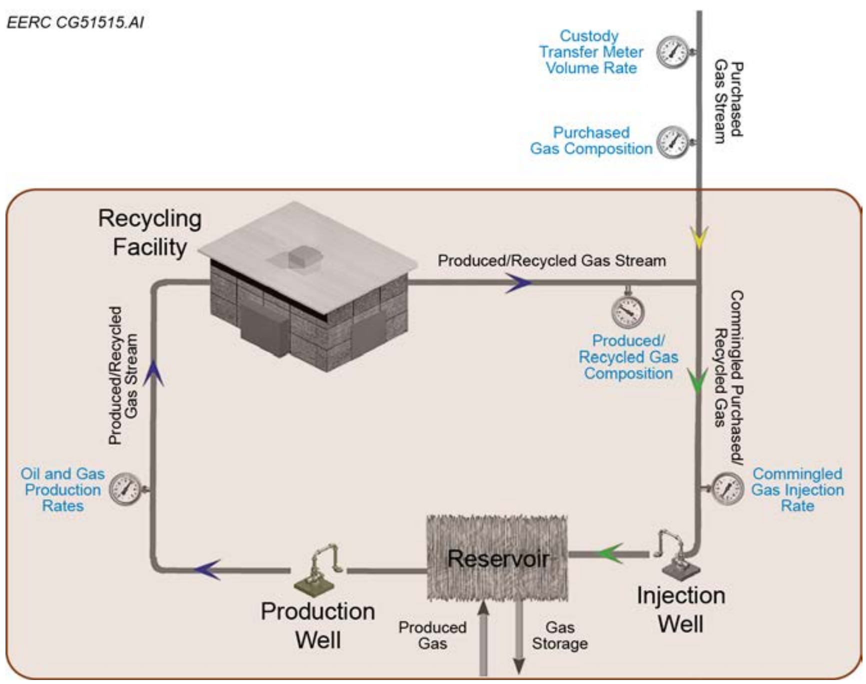

Figure 18. Simplified CO_2 EOR injection and recycling system.

This recycling of produced CO_2 prevents release to the atmosphere; therefore, the process is effectively a closed-loop system for the produced CO_2. As a result, the total amount of storage associated with any CO_2 EOR operation is, essentially, the quantity of purchased CO_2. Small adjustments in the calculation of storage may be necessary to allow for impurities in the CO_2 stream or minor system losses (e.g., occasional venting). The proportion of the recycled component in the CO_2 stream typically increases with time, on a site-specific basis. Well over 95% of the purchased quantity of CO_2 is ultimately stored (Azzolina and others, 2015; Melzer, 2012).

With continued flooding of a reservoir, increasing quantities of produced and recycled CO_2 will typically reduce requirements for purchasing new CO_2. This trend may be masked as new sections of a reservoir are opened up to flooding operations, but ultimately the ratio of recycled to purchased CO_2 will increase over time. Consequently, the total quantity of injected CO_2 over a given time period will comprise both newly purchased and recycled CO_2, with the proportion of the latter increasing over time. This leads to a common misconception, namely that recycled CO_2 is not yet stored; this is incorrect because of the closed-loop nature of the recycling system. At any point in time, the quantity of recycled CO_2 present in the wellbores and surface infrastructure is relatively minor; the vast majority of CO_2 is securely stored within the reservoir. If an operator ceases injection/production and shuts in all wells, the amount of CO_2 not securely stored in that reservoir would be relatively minor or even trivial. Ultimately, almost all the purchased CO_2 is permanently stored in the reservoir.

A related misconception is that a portion of the CO_2 is not stored because of CO_2 movement in the reservoir, as demonstrated by the produced and recycled component. The closed-loop system described above and the integrity of the sealing layers (cap rock) trapping oil, gas and injected CO_2 combine to render the storage as secure; just as mobile, free-phase CO_2 stored in a DSF can be regarded as secure, irrespective of whether secondary trapping mechanisms such as residual, dissolution, or mineral trapping have taken effect.

Figure 19 shows the cumulative quantities of CO_2 stored over time at the Bell Creek CO_2 EOR operation in Montana. The graph shows a steady increase in CO_2 stored over time, corresponding with purchased quantities. The illustrated phases refer to different sections of the field that have been flooded in a sequential manner; it should be noted that Phase 1, the first area to be flooded, shows a steady increase in stored quantity in the first 2 years of operations, followed by relatively small increases beyond 2 years. This perfectly illustrates an increasing proportion of CO_2 being produced and recycled, resulting in reduced quantities of newly purchased CO_2 in the injection stream; hence, the cumulative storage tends to level off. Figure 20 illustrates the increasing proportion of recycled CO_2 in the total cumulative injection for the entire oil field.

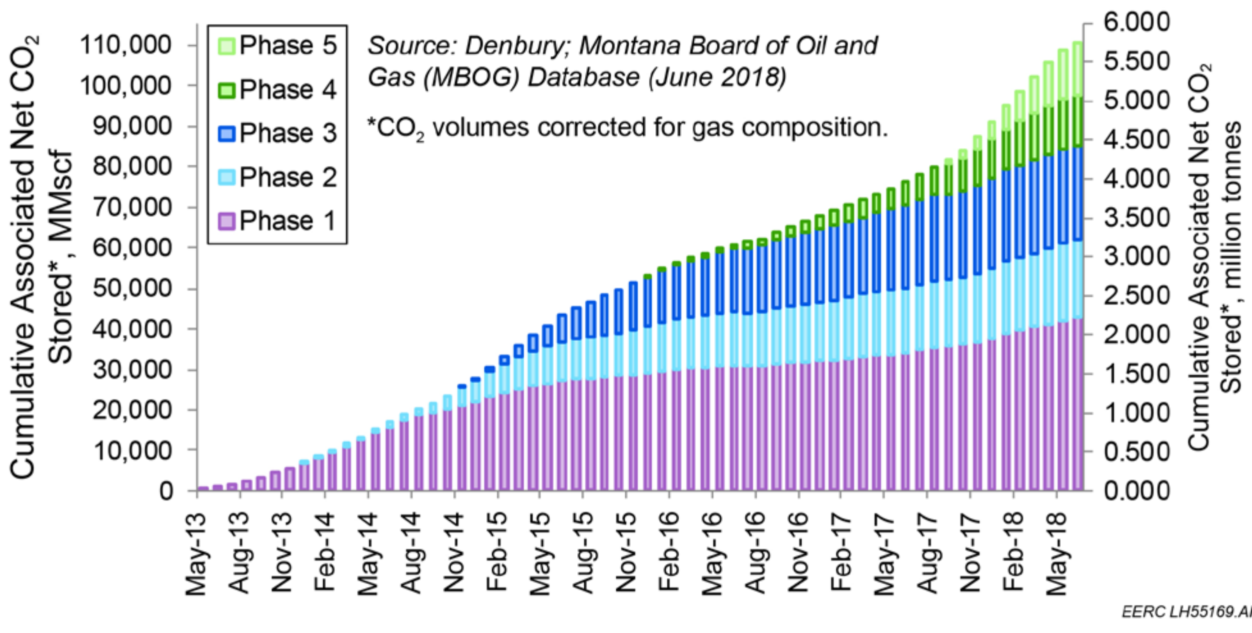

Figure 19. Cumulative associated storage of CO_2 at the Bell Creek oil field, Montana.

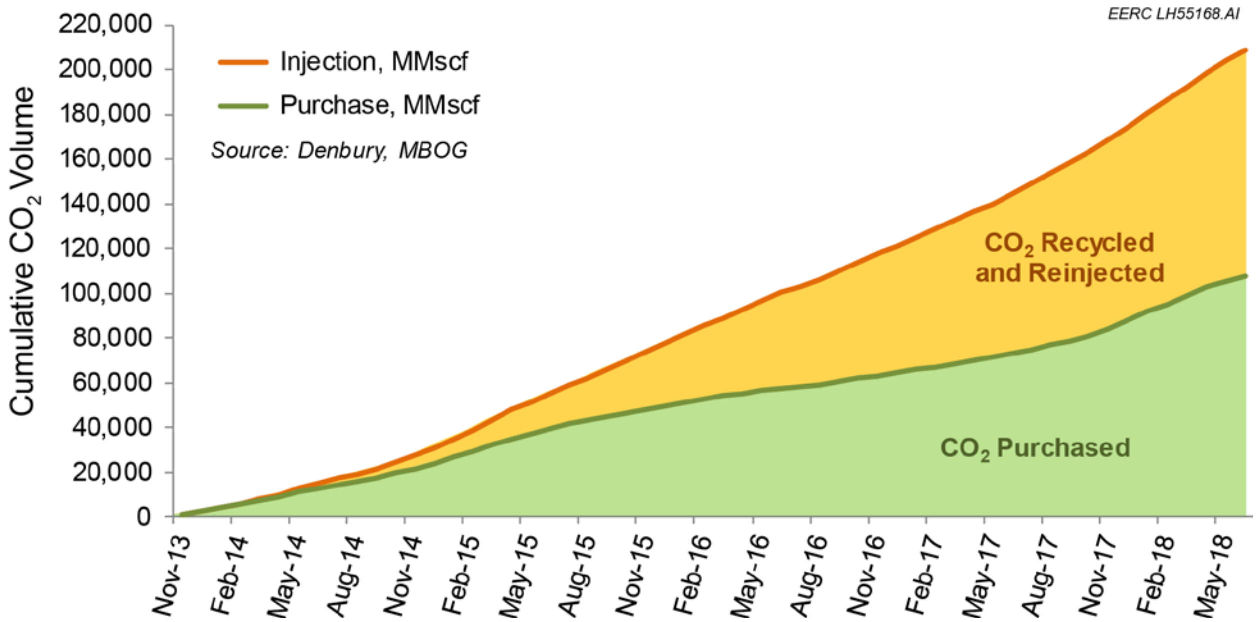

Figure 20. Total cumulative CO_2 injection at Bell Creek.

4.2 Life Cycle Analysis

Life cycle analyses quantifying GHG emissions were undertaken for two scenarios with associated storage: CO_2 sourced from a coal-fired power plant (Azzolina and others, 2016) and CO_2 sourced from a natural gas-processing plant (Jensen and others, 2018). System models underpinning both analyses accounted for upstream, gate-to-gate, and downstream processes. Both models quantified the energy usage and GHG emissions from gas separation and reinjection technologies applied at the EOR site. Therefore, these system models were used to estimate a net life cycle emission factor for the incremental oil that incorporated 1) upstream emissions from the coal-fired power plant or natural gas-processing plant and CO_2 pipeline transport from the plant to the oil field; 2) emissions from gate-to-gate operations to produce the incremental oil; and 3) downstream emissions associated with pipeline transport of the crude oil to a refinery, refining of the crude oil into finished fuels, and combustion of the finished fuels. In addition, these net life cycle emission factors accounted for the associated storage of CO_2 that occurs incidentally during this tertiary method of oil recovery.

The study where CO_2 was sourced from a coal-fired power plant was based on industry data of performance metrics for CO_2 EOR fields compiled mostly from West Texas carbonate floods (Azzolina and others, 2015). The average case resulted in a reduction of the net life cycle emission factor of approximately 12% as compared to published emission factors for conventional oil production. The study also presented optimization scenarios that could further reduce net life cycle emission factors up to 40% lower than conventional oil production.

Modeling of the scenario with CO_2 sourced from a natural gas-processing plant utilized plant- and field-specific data to compare total GHG emissions between a system, which independently produced natural gas and oil, and an alternative system, which captured CO_2 from the natural gas-processing plant and utilized this captured CO_2 for EOR. The modeling results showed that the CO_2 EOR scenario using captured CO_2 produced both natural gas and oil with lower-life-cycle GHG emissions than alternative systems producing natural gas and oil independently. This screening-level assessment estimated GHG emission reductions of approximately 30% between these two scenarios.

The results from both studies show that the use of anthropogenic CO_2 for CO_2 EOR provides a viable means to offset carbon emissions from oil production through the associated storage of CO_2.

5.0 PUBLIC OUTREACH

Since the outset of the PCOR Partnership outreach program in the fall of 2003, the goal has been to become a leading source of public information in the partnership region regarding the PCOR Partnership Program and CCS. This goal was achieved in three ways: 1) general outreach across the region on the partnership itself and CCS; 2) outreach focused on CCS projects; and 3) outreach to key audiences. Activities during Phase III were focused in ten areas of emphasis as summarized below and further described and discussed in Appendix 2.

1. Structure for outreach planning and implementation – Adoption of a modified version of the Macnamara model (Watson and Noble, 2007) to support outreach planning, implementation and review, and to help ensure that the approach to outreach is in alignment with the iterative nature of the technical tasks.

2. Regional geospatial data format for outreach – Further refinement and application of a regional geospatial data format for planning, tracking, and review of outreach activities and product distribution.

3. Data management and operating procedures – Development and implementation of an outreach data management system along with a set of standard operating procedures to ensure consistency for reporting and tracking.

4. Outreach tool kit – Development of 24 products, including four new fact sheets, four value-added updates of Phase II fact sheets, three outreach posters, a variety of PowerPoint slides, two public television documentaries (includes DVD packaging and 20 video clips for use on the Web and in presentations), a four-part video educational series, and a technical "how-to" video.

5. Web site – 45 new Web pages, 39 new materials (12 fact sheets, three outreach posters, 21 video clips, technical short, and new documentaries), HTML to ensure streaming and support video tracking, comprehensive tracking, a project section, a technical poster section, a household carbon footprint section, and, at the end of Phase III, a format update and technical upgrade to help prolong the site's shelf life.

6. Project-level outreach – General information dissemination (ten projects), providing original outreach materials (five projects), serving on formal outreach advisory groups (two projects), and engaging with landowners in the project area (one project).

7. General outreach to audiences – Outreach presentations and packets (e.g., documentary DVDs, regional CO_2 storage atlas, and flash drive with outreach materials) provided to teachers in eight states and one Canadian province; 417 telecasts of seven original documentaries in 34 states and four provinces; and outreach materials (e.g., DVDs, regional atlas) placed in 217 libraries in six states and one province.

8. Regional outreach picture – Progress on building a regional picture of the distributions and relationships of individual outreach components to each other, as well as to CCS infrastructure and potential CCS development.

9. Collaboration and sharing – Along with serving on advisory boards for projects in the region, providing reviews for outreach materials, and presenting the partnership's outreach experience at conferences and meetings, the outreach team also played an active role in the RCSP's Outreach Working Group (OWG) by contributing to the original and revised outreach best practices reports (U.S. Department of Energy National Energy Technology Laboratory, 2009, 2017), co-authoring OWG posters and presentations, and representing OWG in national and international forums.

10. Outreach best practices – The best practices defined for the PCOR Partnership (Daly and others, 2009) contributed to the RCSP Initiative best practices manuals (U.S. Department of Energy National Energy Technology Laboratory 2009, 2017), and continue to be tested and refined by the partnership, being now made available to outreach programs for next-generation projects including the four Carbon Storage Assurance and Facility Enterprise (CarbonSAFE) projects in the PCOR Partnership region (Daly and others, 2018).

6.0 KEY MESSAGES FROM PCOR PARTNERSHIP RESEARCH

The PCOR Partnership, managed by the EERC, has collaborated with a growing membership of over 120 industry, government, and research organizations to encourage the commercial deployment of CCUS in the region as an essential technology to:

- *Support the DOE vision for climate change solutions with affordable, abundant, and reliable energy sources.*

- *Improve resource recovery or deliver market opportunities.*

- *Provide access to developing technology.*

The PCOR Partnership region has suitable geology, an abundance of fossil fuel resources, and an industrial and energy development base that combine to provide an ideal opportunity to deploy CCUS as a carbon management strategy.

– *Extensive characterization work has shown that the PCOR Partnership region has secure CO_2 storage resources sufficient to support the commercial deployment of CCUS over many decades.*

– *An established oil industry across the region provides jobs and economic opportunities for associated CO_2 storage incidental to EOR operations.*

– *CCUS has already been successfully demonstrated in the PCOR Partnership region, including at large scale as part of commercial deployment.*

Carefully selected and monitored storage sites present very low and manageable levels of risk to human health, the environment, and other natural resources.

– *The PCOR Partnership has successfully integrated monitoring data from operating sites, using an AMA, to demonstrate secure associated storage.*

– *Risks associated with large-scale storage have been demonstrated as low and manageable for appropriately characterized and monitored sites.*

Technology already developed by the oil and gas industry, supplemented by other innovative techniques, can be used to monitor the CO_2 injected in the subsurface and provide assurance that the environment is not being negatively impacted.

– *Achieved effective application of monitoring strategies to track the migration of 5.9 Mt of associated CO_2 storage at a commercial-scale project.*

– *Comprehensive monitoring showed no evidence of leakage or environmental impacts associated with large-scale CO_2 storage.*

Storage associated with EOR can provide economic benefits including jobs, increasing the production and extending the life of existing oil fields while reducing emissions.

– *The Phase III Bell Creek Project has demonstrated the technical viability of associated CO_2 storage as a means to support the commercial deployment of CCUS.*

– *Detailed life cycle analysis has been used to show the GHG mitigation benefits of associated CO_2 storage, reducing the environmental footprint of economic activity.*

Adoption and development of communications best practices have allowed the PCOR Partnership to increase public awareness of CCUS in the region and around the world through an active, multifaceted outreach program.

– *The geospatial framework used for technical components of the project can be used for outreach activities, helping to track public engagement and guide product development.*

– *The PCOR Partnership Program has demonstrated the value of a collaborative approach that builds on partner knowledge, experience, expertise, reputation, and in-place outreach pathways.*

– *The PCOR Partnership Program has demonstrated the value of delivering a consistent CCUS story, modified for specific audiences.*

7.0 FUTURE VISION FOR THE PCOR PARTNERSHIP

The PCOR Partnership has built an extensive and engaged group of over 120 member organizations, providing the leading regional forum to promote CCUS knowledge sharing and collaboration between industry, government and other stakeholders. Our vision for the future of the PCOR Partnership sees this role expand as CCUS project deployment in the region gathers pace. Financial incentives such as the 45Q federal tax credits and increased confidence in regulatory oversight, highlighted recently by Class VI primacy in North Dakota, are providing fresh impetus to fossil fuel-based industries actively seeking reductions in the carbon intensity of their operations. In addition to the power-generation sector, industrial CO_2 sources such as ethanol facilities are increasingly a focus for CCUS projects. Continuation of applied R&D, with a focus on support for the development of surface and subsurface infrastructure, plays a vital role in supporting CCUS project deployment. Research efforts directed toward cost reduction for all elements of the CCUS chain can also maintain momentum for CCUS projects moving forward.

A priority focus for future R&D is the development of monitoring technologies that can provide real-time, integrated interpretation of the subsurface and of the processes associated with CCUS. The development of such techniques, allied to the rapid evolution of machine learning, can make a significant contribution to the management of the large-scale injection and storage operations needed to support meaningful CCUS deployment.

Our Vision for CCUS

1. Commercial CCUS providing major economic benefits.

2. Secure, large-scale CO_2 storage achieved across a wider range of geologic environments.

3. Lower-carbon-intensity oil and gas production with CO_2 EOR.

4. Improved and novel technologies for injecting CO_2 in the subsurface.

5. Opportunities for infrastructure development to underpin CCUS.

6. Advancement of CO_2 storage opportunities with unconventional resources from current low technology readiness levels toward pilot-scale deployment.

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APPENDIX 1

TASK 1 – REGIONAL CHARACTERIZATION

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INTRODUCTION

Developing a comprehensive understanding of the magnitude, distribution, and variability of major stationary carbon dioxide (CO_2) sources and potential CO_2 storage targets is required to determine the feasibility of widespread implementation of commercial-scale CO_2 storage projects. As part of the Plains CO_2 Reduction (PCOR) Partnership Phase III efforts at the Energy & Environmental Research Center (EERC), work started in Phases I and II has continued to refine the characterization of sources, prospective geologic storage resources, and infrastructure within the region. The EERC has refined CO_2 storage resource estimates for deep saline formations (DSFs) and enhanced oil recovery (EOR) opportunities and provided additional context for interpreting the commercial-scale implications of the results of large-scale demonstrations.

Geologic CO_2 storage is a technology that 1) is immediately applicable as a result of demonstration projects in addition to the experience gained in oil and gas exploration and production, natural gas storage, deep waste disposal, and groundwater protection; 2) has large capacity, although unevenly distributed; and 3) has retention times of centuries to millions of years (Intergovernmental Panel on Climate Change, 2005). Geologic storage of CO_2 is undertaken on a commercial scale at several locations around the world, including in the PCOR Partnership region (discussed in following sections of this appendix). Geologic media identified as most suitable for CO_2 storage are oil and gas reservoirs and DSFs. Depleted hydrocarbon reservoirs have the advantage of demonstrated confinement properties and, in some instances, the ability to both produce incremental oil and achieve associated storage of CO_2 during EOR via CO_2 injection; however, these reservoirs are often penetrated by many wells, which have the potential to increase the risk of diminished storage security over time. DSFs have the advantage of being much more widespread, representing a significantly larger storage resource, and generally presenting less risk of CO_2 leakage along existing wells because they are penetrated by fewer wells than hydrocarbon reservoirs. A third but less attractive geologic medium for CO_2 storage is uneconomical coal beds. This medium has the smallest potential in terms of storage capacity and is an immature technology that has not yet been proven.

Within the PCOR Partnership region, characterization efforts have identified significant CO_2 storage resource potential comprising 368 to 1220 billion tonnes (Gt) of storage in currently evaluated saline formations (range from P_{10} and P_{90} estimates), 25 Gt in depleted oil field reservoirs, 8 Gt in unminable coal, and 1.71 to 10.26 Gt in selected oil fields that are candidates for CO_2 EOR (Peck and others, 2016). While DSFs have the most significant storage potential, the site-specific and regional estimation of this potential typically requires a significant characterization effort.

Throughout the course of implementing the Phase III portion of the PCOR Partnership Program, a number of significant discrete efforts have been implemented that have contributed to the overall goal of regional characterization. These efforts are briefly described as follows.

REGIONAL ENGAGEMENT

To adequately and efficiently investigate the potential for geologic storage of CO_2 across the 1.4 million square miles of the PCOR Partnership region, the PCOR Partnership contacted representative state and provincial geologic surveys and/or oil and gas divisions. As an example, in 2008, the Missouri Department of Natural Resources Division of Geology and Land Survey was added as a PCOR Partnership member and subcontracted to provide baseline data and characterization regarding potential geologic storage of CO_2 in Missouri. Other organizations with which working relationships were put in place by the PCOR Partnership regional characterization team included the following:

- Iowa Geological Survey – Obtained information on the DSFs of the Forest City Basin in southwestern Iowa.

- North Dakota Department of Mineral Resources, Montana Board of Oil and Gas, Nebraska Oil and Gas Conservation Commission, and Wyoming Oil and Gas Conservation Commission – Acquired updated cumulative oil production numbers for the fields and pools in the U.S. portion of the PCOR Partnership region along with critical reservoir values such as OOIP (original oil in place), porosity, permeability, and production acres, which were used to update the CO_2 EOR estimates for many fields.

- Appropriate agencies in Alberta, Saskatchewan, and Manitoba in Canada – Secured data similar to those acquired for the potential U.S. storage sites.

The development of these working relationships allowed for efficient acquisition of data and, as importantly, established direct contacts with individuals who provided additional context that aided in the proper interpretation of the data.

REVIEW OF REGIONAL SOURCE ATTRIBUTES

The EERC has developed and maintained a database of large-scale stationary point sources of CO_2. This database represents one of the key sources of information required to develop CO_2 capture–transportation–storage scenarios with the potential to reduce greenhouse gas (GHG) emissions in the PCOR Partnership region. To keep the database current over the course of the project, the data set was subjected to an annual review in which new or previously missing CO_2 sources were identified and added, annual CO_2 emission rates of sources were updated, and facility locations were verified. The review process also identified CO_2 sources in the region that were no longer active.

Over the course of the Phase III project, the minimum CO_2 emission rate for sources to be included in the database was increased from 15,000 tonnes per year in 2008 to 100,000 tonnes per year. This increase in the threshold was driven by two primary factors: 1) There is a consensus view that 100,000 tonnes/yr is likely the minimum size for capture systems to be economically viable and 2) 100,000 tonnes per year represents the threshold value for sources as defined by the other U.S. Department of Energy (DOE) Regional Carbon Sequestration Partnerships (RCSPs) and entered into NATCARB (National Carbon Sequestration Database and Geographic Information System). Using this new threshold limit for sources about 400 CO_2 sources in the PCOR Partnership region were identified that are candidates for CO_2 capture, which together emit approximately 469 million tonnes (Mt) annually. The actual number of facilities fluctuates over time based on actions such as facility closures or increases of facility emissions associated with increases in product output (Jensen and others, 2017).

ASSESSMENT OF REGIONAL STORAGE CAPACITY

Through the period of Phase III, the EERC assessed several oil-bearing basins in the PCOR Partnership region, specifically the Alberta, Williston, Powder River, and Denver–Julesberg Basins. Multiple oil fields were identified to evaluate CO_2 utilization for EOR and associated CO_2 storage. Two sites, the Eland/Lodgepole Mounds and Rival oil fields in North Dakota, were selected to address opportunities to use potential locally sourced CO_2 for EOR. In addition, in 2011 the EERC initiated collaboration with the Petroleum Technology Research Centre (PTRC) at the University of Regina on a CCUS project in southeastern Saskatchewan, Canada (Aquistore Project), to demonstrate the feasibility of CO_2 storage in a DSF and led the U.S. component of a 3-year binational effort between the United States and Canada to determine the CO_2 storage resources in a 1.34-million-km^2 area of the Cambrian–Ordovician Saline System (COSS), present across the Alberta and Williston Basins in Canada and the U.S. The results of the oilfield studies and Aquistore Project are briefly summarized here; a high-level summary of the storage resource estimates from the COSS study, which was assigned its own task, are provided in Table 1-1 and presented in more detail in the Task 16 summary. As shown in Table 1-1, the COSS was characterized as a large and viable target for long-term geologic storage of anthropogenic CO_2.

Table 1-1. Range of CO_2 Storage Estimate for the Portion of the COSS Suitable for CO_2 Storage at the P_{10}, P_{50}, and P_{90} Probability Levels

Probability		**P_{10}**	**P_{50}**	**P_{90}**
Saline Formation Efficiency Factor		1.2%	2.4%	4.1%
CO_2 Storage Resource	United States	14 Gt	28 Gt	48 Gt
	Canada	43 Gt	85 Gt	145 Gt
	Total	57 Gt	113 Gt	193 Gt

The early focus on CO_2 storage and utilization in oil fields was founded on the concept that oil fields are generally much better characterized than saline formations; are already legally established for the purpose of safe, large-scale production and/or injection of subsurface fluids; and offer a means to offset the considerable costs of CO_2 capture, compression, transportation, and implementation through the sale of incrementally-produced oil. These attributes make oil fields the most cost-effective near-term choices in the PCOR Partnership region for large-scale CO_2 storage projects.

Dickinson Lodgepole Mounds (DLMs)

The DLMs (including the Eland oil field) near Dickinson, North Dakota, were identified as possible targets for CO_2 storage and CO_2 EOR activities because of their history of high oil recovery factors and very successful waterflooding operations (Knudsen and others, 2010). Site characterization indicated the DLMs have an estimated a range (P_{10} and P_{90} estimates) of incremental oil recovery potential of 21 million to 34 million barrels and associated storage of 6 million to 15 Mt of CO_2. These results indicate the DLM fields are excellent targets for both CO_2-based EOR operations and long-term associated storage of large volumes of CO_2.

Rival Oil Field

The Rival oil field of northwestern North Dakota encompasses just over 20 mi^2 and has produced over 16 MMbbl of oil since the late 1950s, with most recovery now occurring in secondary production via waterflooding. Site characterization efforts focused on a 100-square-mile study area that was centered on the Rival oil field, providing data to develop 3-D geologic models (Braunberger and others, 2012). These models were used to develop an improved understanding of the spatial distribution of reservoir properties and the estimates of potential incremental oil and associated CO_2 storage. A volumetric approach using OOIP, an assumed 15% incremental oil production, and CO_2 net utilization factors ranging from 5000 to 8000 scf/bbl resulted in an estimated production of 6.0–9.0 MMbbl of incremental oil from the Rival oil field and the potential storage of 1.5–2.9 Mt of CO_2. Dynamic predictive simulations using CO_2 Prophet suggested an incremental recovery of 15.8%–18.5% (13–15 MMbbl of oil) at 1 HCPV (hydrocarbon pore volume) CO_2 injection and 26.9%–28.6% recovery (23–24 MMbbl of oil) at 2 HCPV. The volume of CO_2 required, and ultimately stored, was calculated to be 2.5 Mt for the 1 HCPV scenario and up to 3.5 Mt for the injection of 2 HCPV.

PTRC Aquistore Project

The Aquistore project is focused on demonstrating the feasibility of CO_2 storage in a DSF. The project is operated by SaskPower and is part of the world's first commercial postcombustion CCUS project from a coal-fired power-generating facility, the SaskPower Boundary Dam, serving as the storage site for a portion of the captured CO_2 from the power plant. The Aquistore site includes one injection well and a 152-meter offset observation well. Intermittent CO_2 injection commenced at the site in April 2015. Injection quantities were limited by capture plant operating conditions and CO_2 sales obligations. Daily injection rates ranged up to 300 tonnes during injection periods in 2017. As of September 30, 2017, approximately 104,600 tonnes of CO_2 has been injected and stored.

The PCOR Partnership components of this collaboration included assisting in site characterization, acting as advisor in risk assessment and monitoring, verification, and accounting (MVA) activities, directly performing aspects of modeling and simulation activities, and participating on the Aquistore advisory board. Specific examples of primary activities of the EERC are as follows:

- The EERC developed and refined geologic models encompassing the Aquistore project area and performed predictive simulations and history-matching efforts to replicate early injection and observation well behavior. Pressure response of the observation well to CO_2 injection was documented and matched by the simulation, indicating good agreement among model porosity, injection fluid distribution, mass balance, and overall interwell permeability. Simulation of near-wellbore performance of the injection well proved to be more challenging as an apparent level of formation damage in some intervals and stimulation in others was observed during the initial months of CO_2 injection.

- The EERC constructed a simplified simulation model based on physical aquifer properties obtained from previous mean probability (P_{50}) static geologic model realizations for the purpose of 1) better understanding the storage implications of injecting CO_2, 2) history-matching the field pressure response, and 3) predicting CO_2 plume evolution at the Aquistore site. Simulations were also conducted utilizing this model to better understand both operational and geologic uncertainties that may exist at the Aquistore site. Modeling and simulation approaches and learnings are documented in a report by Jiang and others (2016).

IMPROVEMENTS TO THE DOE SALINE STORAGE METHOD

The PCOR Partnership accrued valuable insight into the methods for CO_2 storage resource and capacity estimations for DSFs through its involvement with DOE and the international community. This insight resulted in the development of a workflow that introduced intermediate storage efficiency factors (Peck and others, 2014). By accounting for increased levels of geologic reconnaissance (e.g., geographic distribution of salinity and depth values), these efficiency factors generate refined CO_2 storage resource values for saline formations. This advancement in the understanding and application of what has become the standard DOE method for saline formation CO_2 storage capacity assessment is notable. These improvements in the application of the DOE saline storage-capacity estimation method limit the frequent misinterpretations that result from simply applying the formula to the gross characteristic values of a saline formation. For example, a formation should not be considered for CO_2 resource evaluation if there is no indication of what geographic extent is deep enough to sustain supercritical CO_2 and what portion of the reservoir extent has water salinities greater than 10,000 ppm total dissolved solids (TDS). In cases where depth and salinity are known, then a refined level of storage efficiency factors should be determined and applied.

RESOURCES AND OUTREACH TOOLS RELEVANT TO REGIONAL CHARACTERIZATION ASSESSMENTS

PCOR Partnership Atlas

Among numerous other climate change topics, the PCOR Partnership Atlas provides a regional profile of CO_2 sources and potential sinks across the nearly 1.4 million square miles of the PCOR Partnership region of central North America. Since its inception in 2005, the atlas has continued to serve as an excellent resource, as well as a valuable outreach tool. During the Phase III project period, the PCOR Partnership Atlas continued to expand and evolve with the development of Versions 3, 4, and 5 along with interim editions of each of these three major editions. The interim editions were printed to accommodate demand for the product and allowed for minor updates and typographic errors to be addressed. For example, the latest edition of the atlas (i.e., Version 5) includes new discussions of such topics as CO_2 EOR life cycle GHG emissions and the CO_2 storage estimates of the COSS. The atlas versions were scheduled on a biennial basis on years alternate to DOE's update of the Carbon Sequestration Atlas of the United States and Canada, as produced by the DOE National Energy Technology Laboratory (NETL). This alternating schedule allowed for select materials generated for the PCOR Partnership Atlas to be efficiently provided to DOE NETL for use in its national atlas.

Numerous copies of the atlas have been distributed to industry representatives, visitors, educators, and libraries through various means such as the PCOR Partnership annual membership meetings, North Dakota teacher's workshops, and upon request, including via the public PCOR Partnership Web site. In Phase III alone, the three editions of the atlas were distributed as follows:

- 3rd Edition – 800 copies of the atlas and 450 copies of the revised, interim atlas (Peck and others, 2010)

- 4th Edition – 1200 copies of the atlas (Peck and others, 2012) and 1250 copies of the revised, interim atlas

- 5th Edition – 1000 copies of the atlas (Peck and others, 2016) and a pdf version only of the revised, interim atlas (no copies of this version of the atlas were printed) (Peck and others, 2017)

Overall, since its first printing in 2005, over 6500 atlases have been distributed to interested third parties.

PCOR Partnership Decision Support System (DSS)

The PCOR Partnership DSS was launched as part of the PCOR Partnership Phase I efforts and was envisioned as a portal through which project members could obtain information regarding reports, abstracts, and posters as well as annual membership meeting presentations (accessed via password).

Whereas conventional Web pages provide access to relatively static data, such as links to reports, CO_2-related Web sites, terrestrial maps, and snapshots of regional data, the DSS also contains an interactive geographic information systems (GIS) interface that allows users to explore data related to CO_2 sources and potential geologic storage targets. New PCOR Partnership products (reports, abstracts, posters, presentations) are regularly added to the database after they are approved for release to partners. Currently, the database contains over 1370 items produced by the PCOR Partnership since its inception in 2003.

Modifications and refinements to the DSS have occurred on relatively frequent basis to ensure the timely dissemination of data and information, as well as to improve its value to the PCOR Partnership partners as they move forward with their carbon management decisions. More recently, there have been a couple of major redesigns during the Phase III project period. These larger efforts were driven primarily by the need to improve the accessibility of the information, but also, in part, by changes in GIS programming capabilities. Of particular value to linking carbon sources with target storage areas, recent improvements to the GIS application provided an advanced search tool to enhance the ability to search using different source attributes. Specifically, the tool allows the user to search by source type, source name, and source CO_2 amounts, including use of these same attributes to remove sources that do not fit certain criteria. For example, one can search for all ethanol plants and, from that search, eliminate any sources with a CO_2 output of less than 25,000 metric tons. There is also an option of exporting search results. Searching oil fields was also improved by allowing the user to search oil fields by name.

Demonstration Project Reporting System (DPRS)

The PCOR Partnership DPRS was originally envisioned to provide structured access to data from the PCOR Partnership Phase III demonstration projects at Bell Creek and Fort Nelson, as well as facilitate communication and interpretation of data via the DSS. With the development of DOE's Energy Data eXchange (EDX)—which has a wider application and functionality than PCOR's DSS, a larger user base, and long-term viability beyond the project—data from the PCOR Partnership were instead submitted annually to that workspace. Instead of housing the data, the PCOR Partnership compiled a series of Web pages to highlight the various aspects of the two large-scale demonstration projects (Fort Nelson and Bell Creek). These pages contain information on background and scope of work; benefits to the region; characterization data, modeling, MVA, risk management, regulations and permitting, and products. Data and information for each of the field demonstration projects, upon receipt of approval from the commercial site owner/operator, were provided in PowerPoint presentations at meetings and conferences. In March 2017, CO_2 injection data and oil/gas/water production data for the Bell Creek oil field were submitted to DOE's EDX. The data submitted include monthly values from the start of injection in May 2013 through December 2016.

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APPENDIX 2

TASK 2 – PUBLIC OUTREACH AND EDUCATION

TASK 2 – PUBLIC OUTREACH AND EDUCATION

INTRODUCTION

During Phase III of the Plains CO_2 Reduction (PCOR) Partnership, the Energy & Environmental Research Center (EERC) continued to be a public source of information on the partnership and carbon capture and sequestration (CCS) in the region. The overall outreach and education effort comprised a three-prong approach: 1) general information on the partnership and CCS was made available through a Web site and regional telecasts, 2) outreach and education materials were produced and distributed for each of the CCS projects of the partnership, and 3) materials and information were generated to raise awareness about CCS among key audiences across the region. Over the course of the program, outreach action plans have been updated periodically (Daly and others 2008, 2010, 2016). Brief summaries of the primary activities that were performed during Phase III are provided here.

OUTREACH PROCESS MODEL

During Phase III, the process model shown in Table 2-1 (based on the Macnamara model) was adopted for Task 2 (Watson and Noble, 2007). The model divides outreach activities into three parts—inputs (development stage for activities or products), outputs (activity implementation and/or product distribution), and outcomes (assessment of the impact on the intended audience). A standardized form, which outlined the actions for each of these three tasks under the model, was developed and completed for each activity and product. The information was then entered into a spreadsheet to capture information on activity/product background, status, and lessons learned. Phase III efforts focused primarily on inputs (product development) and outputs (activities, product distribution/exhibition, and tracking) because the effort needed for a detailed outcome assessment was deemed beyond the scope of this task. As such, information regarding outcomes was only informally collected and only for select activities (e.g., landowner contact at the Bell Creek CO_2 EOR site). The model provided an iterative, adaptive management approach (AMA), similar to the AMA implemented for the technical scope of work, to ensure the continued refinement of outreach and education efforts over time.

Table 2-1. Outreach Product/Action Process Model

Steps	Item	PCOR Partnership Action/Experience
Inputs	Development of product(s) or activity(ies)	Discussions with team, managers, advisors, and stakeholders; incorporation of lessons-learned; conduct of focus groups; submissions for peer review and/or award competitions; and QA/QC[1] of activity/product stages and versions.
Outputs	Exposure to product or activity	Tracked Web visits, media stories, product distribution, presentations, etc.; recorded feedback; conducted quarterly reviews; QA/QC; and reporting.
Outcomes	Impact of product or activity	Reviewed nature of feedback (e.g., content of media stories, viewpoints of landowners) and distilled lessons-learned.

[1] Quality assurance/quality control.

DATA MANAGEMENT AND STANDARD OPERATING PROCEDURES

A combination of Microsoft Access database files and Microsoft Excel spreadsheets were developed and implemented during Phase III to house data related to outreach outputs and social characterization efforts. This capability was collectively recognized as the outreach information system (OIS). In conjunction with this effort, guidance documents in the form of in-house and value-added reports were developed to help ensure accuracy and consistency in the future for tracking efforts. Notable among these was Crossland and others (2016), which laid out a protocol for ensuring that Web page programming provided comparable results over time for quarterly tracking using Google Analytics.

STRENGTHENING OF REGIONAL GEOSPATIAL DATA FORMAT

The OIS was combined with a geospatial data format for outreach. Outreach layers included locations of projects, school districts, political and regulatory boundaries, and media circulation and broadcast areas. This permitted investigation of relationships between outreach layers and other project attributes such as CO_2 source, CO_2 sink, demographics, land use, and regulatory information, all of which were available for the region through the PCOR Partnership's decision support system (DSS). To help with outreach planning, the region was divided into 22 subregions (Figure 2-1) that reflected geologic features and political boundaries following the concept of the base map of the American Association of Petroleum Geologists Committee on Statistics of Drilling (Meyer and others, 1991).

ORIGINAL OUTREACH MATERIALS AND VALUE-ADDED UPDATES OF EXISTING MATERIALS

The outreach task produced 24 outreach deliverables, including fact sheets, outreach posters, video products, Web pages, and value-added product upgrades. These products increased the total of outreach products in the outreach tool kit to 50. The Phase III products are listed in Table 2-2.

STRENGTHENING OF WEB SITE AS A COMPREHENSIVE SOURCE OF INFORMATION

The PCOR Partnership Web site anchors public outreach efforts at both the local and regional level by acting as a source for readily available information on CCS, in general, and for individual CCS projects in the region. Online since June 2004, the 90-page Web site presents background on CCS and its role in carbon management, and identifies past and current projects in the region. The site features videos that can be streamed (seven original documentaries and 63 original video clips), as well as a number of downloadable products including 142 technical reports, 67 technical and four public outreach posters, 25 fact sheets, and a 120-page regional atlas of CO_2 storage resources in the PCOR Partnership region.

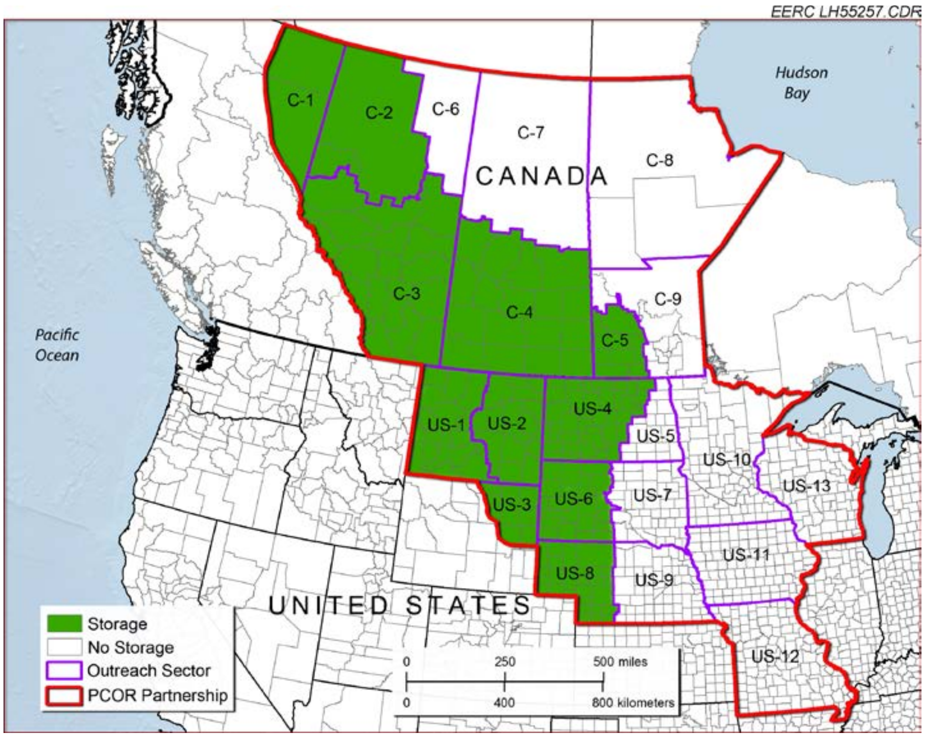

Figure 2-1. Map of the PCOR Partnership region showing the 22 outreach subregions including the 11 subregions (green) where storage may be feasible.

During Phase III, the Web site was enhanced by updating and increasing page text, expanding content, improving tracking capabilities, and incorporating technical upgrades. Major enhancements included:

- Development and implementation of 45 new Web pages.

- Addition of new materials, including eight project fact sheets, four Water Working Group fact sheets, three project-related posters, 21 new video clips, and two documentaries.

- Implementation of HTML5 capability to ensure improved streaming and video-tracking capability.

- Implementation of Google Analytics, which allowed for the tracking of visitor interactions with all Web site elements, including Web pages, PDFs, and videos.

- Establishment of a standard operating procedure (SOP) for Web development and programming to ensure proper interaction with Google Analytics tracking.

- Establishment of a *Projects* section that currently provides information on the 17 completed or active CCS projects in the region, including the six non-PCOR Partnership projects that have been implemented in the PCOR Partnership region since

Table 2-2. Phase III Additions to the PCOR Partnership Outreach Tool Kit[1]

Designation	Product[1]	Availability Date
Fact Sheet 10A,B	CO_2 Sequestration Test in a Deep, Unminable Lignite Seam	09/2016
Fact Sheet 11A	Terrestrial Carbon Sequestration Validation Test	05/2017
Fact Sheet 12A	CO_2 "Huff 'n' Puff" Validation Test	04/2016
Fact Sheet 14	PCOR Partnership – Demonstrating CO_2 Storage in the Northern Great Plains (Phase III General)	06/2008[2,3]
Fact Sheet 15	Risk Management	10/2009
Fact Sheet 16	Geological Storage of Sour CO_2 from a Natural Gas Processing Plant – A Commercial Demonstration	06/2009[2]
Fact Sheet 17	Bell Creek CO_2 Sequestration Monitoring Project	03/2011[2]
Fact Sheet 18	PCOR Partnership Role in the Aquistore Project	02/2014[2]
Documentary 6	"Coal: Engine of Change"	03/2018[4]
Documentary 7	"The Bell Creek Story: CO_2 in Action"	06/2017[4]
Video Segments	Support segments for PowerPoint presentations, North Dakota Studies, PBS Learning Media and PCOR Partnership Web sites	12/2008
Video Series	"Education Video Series — Meeting the Challenge" (4 parts)	
	Part 1: "Energy"	06/2013[4]
	Part 2: "Energy and Carbon"	06/2014[4]
	Part 3: "Finding Solutions"	01/2018[4]
	Part 4: "Carbon Capture and Storage"	01/2018[4]
Tech Video	"Installing a Casing-Conveyed Permanent Downhole Monitoring System"	10/2014[4]
Atlas	PCOR Partnership Atlas of CO_2 storage resources	10/2005[2]
Public Web Site	PCOR Partnership public Web site (www.undeerc.org/pcor)	06/2004[5]
PowerPoint	General Phase III PowerPoint	05/2008[2]
PowerPoint	Fort Nelson PowerPoint	07/2009[2]
PowerPoint	Bell Creek PowerPoint	03/2011[2]
Display Booth	PCOR Partnership public outreach display booth	06/2007
Public Poster 2	Bell Creek Site – CO_2 Emissions Go to Work to Produce More Oil	03/2009
Public Poster 3	Fort Nelson Site – Natural Gas with a Reduced Carbon Footprint	02/2011
Public Poster 4	Aquistore: Demonstrating Carbon Storage	01/2014
Public Poster 5	Reducing Greenhouse Gas Emissions (CO_2 EOR and CCS)	01/2014
Press Releases	Multiple products developed and released by the EERC	On file[6]

1 Products developed by PCOR Partnership only; outreach products available to PCOR Partnership from U.S. Department of Energy (DOE) and other organizations are not listed here.

2 Updated periodically.

3 Fact sheet changed from 11 to 14.

4 Joint PCOR Partnership–PPB production aimed at general audiences; available for broadcast or in DVD format.

5 Fact sheet replaced "PCOR Partnership Phase II."

6 Created as required.

2016 (i.e., four CarbonSAFE projects and two other projects that involve PCOR Partnership members).

- Addition of a *Household Carbon Footprint* section in 2016, which was funded by the North Dakota Department of Commerce (a PCOR Partnership member) and focused on household energy and carbon, including the role that CCS could play in reducing the household carbon footprint.

- Upgrade of both format and function of the Web site in 2018 to extend and optimize its "shelf life" beyond the end of Phase III.

Since April 2010, Web site visits have been tracked using Google Analytics, a free Web analytics software. This program is an essential component for tracking visits overall, as well as providing limited evaluation of visitor interactions within the Web site. Figure 2-2 shows quarterly Web visits to the public Web site from April 2010 to the end of September 2018. In the period before instituting comprehensive Web site tracking in October 2013, counted quarterly visits were typically below 1000; however, since the end of 2014, counted quarterly visits have exceeded 5000. Part of this increase is believed to be the result of instituting comprehensive tracking in October 2013 (i.e., it is now possible to see the full extent of Web site activity going forward) combined with the institution of SOPs that ensured that all Web pages and components were trackable going forward. Throughout, the top pages that have been viewed on the Web site are: *What Is* CO_2 *Sequestration* (33%), *What Is* CO_2 (29.4%), *Regional* CO_2 *Sequestration Projects* (3.5%), and *Terrestrial Sinks* (2.7%). More intensive and detailed analysis of Web site activity, which would require more advanced and more costly analytical services, was deemed beyond the scope of work of the PCOR Partnership.

PROJECT-LEVEL OUTREACH ACTIVITIES

As shown on Figure 2-3, the partnership provided some level of outreach for several CCS-related projects in the region during Phase III.

The partnership participated on the outreach advisory panels for two CCUS projects managed by the Petroleum Technology Research Centre (PTRC) in Regina, Saskatchewan, Canada. As a member of the CO_2 EOR Weyburn–Midale project outreach advisory panel from 2007 to 2012, the partnership took part in advisory meetings and conference calls, outreach planning, review of outreach materials, and development of the public Web site of the project. Similarly, as a member of the Aquistore project outreach advisory panel from 2009 to 2017, the partnership served as a reviewer/advisor on the project outreach plan and supported community open houses by providing review comments, selected outreach materials, and personnel.

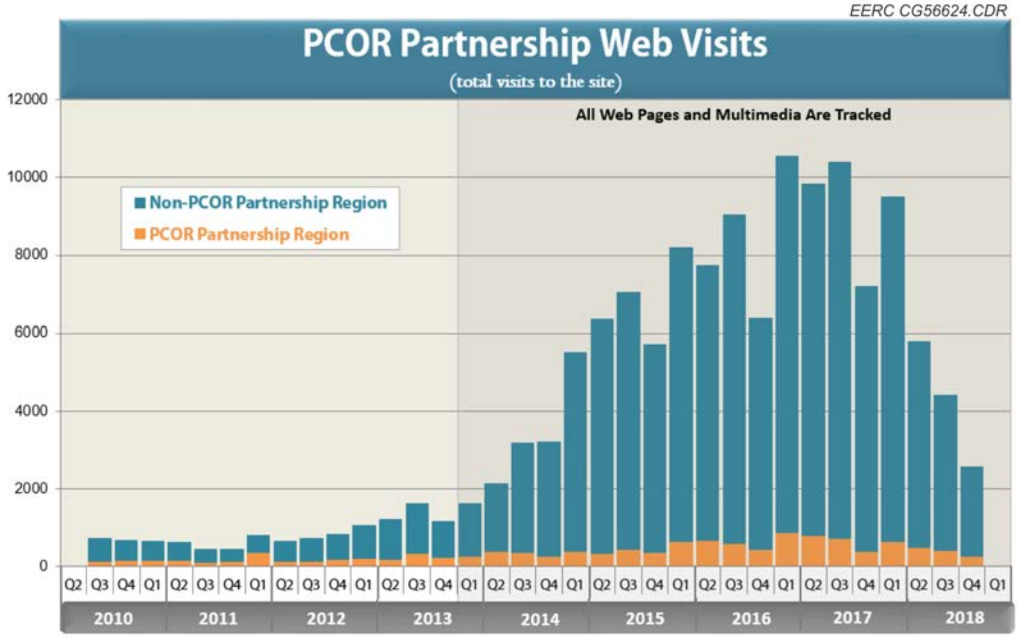

Figure 2-2. Graph showing total visits to the public Web site (Y axis) by year and quarter (X axis) for the period April 2010 to December 2018 from within the PCOR Partnership region (orange) and outside the region (blue). Beginning October 2013, the PCOR Partnership transitioned to tracking all Web pages and multimedia in the site.

Other notable project-based activities include the development of outreach materials (e.g., fact sheets, outreach posters, PowerPoint materials) for Spectra Energy Transmission's (SET's) Fort Nelson project in British Columbia, Apache Canada's Zama project in Alberta, and SaskPower's Boundary Dam project in Saskatchewan, all of them in Canada. Lastly, for the partnership's Phase III Bell Creek project, outreach materials were developed and provided to the commercial partner, Denbury Resources Inc. (Denbury), and local stakeholders. The partnership also interacted with landowners and provided written reports with sampling results as a part of water-monitoring efforts at and/or near the Bell Creek project site.

OUTREACH TO OTHER AUDIENCES

As shown in Table 2-3, Phase III outreach and educational activities continued to provide a combination of original television programming, outreach to educators, and placement of materials in local libraries. Additional information sessions with opinion leaders are discussed under the management task, and outreach to project-specific landowners is discussed under project-level outreach.

Figure 2-3. Outreach activities by the PCOR Partnership on CCS-related projects in the PCOR Partnership region.

General Public

Telecasts of original documentaries coproduced by the PCOR Partnership and Prairie Public Broadcasting (PPB) were a major strategy for outreach to the general public. As shown in Figure 2-4, there were a total of 852 documentary telecasts in 36 states and four Canadian provinces, all carried by Public Broadcasting Service (PBS) channels (PBS was carried by cable in Canada).

Approximately 30% of these broadcasts aired in the PCOR Partnership region of North Dakota, northwestern Minnesota and southern Manitoba, and another 25% outside of the PPB area but still within the PCOR Partnership region. The four Phase II documentaries accounted for 629 broadcasts in 36 states and four Canadian provinces.

Two original television documentaries were coproduced with PPB during Phase III: "The Bell Creek Story: CO_2 in Action" (1/2-hour in length; premiered on PPB in June 2017) and "Coal: Engine of Change" (1 hour in length; premiered on PPB in May 2018). Both shows were promoted by PPB and premiered in the prime midevening viewing slot. The Bell Creek documentary had 22 telecasts while the coal documentary had 31 telecasts. Both shows were marketed to PBS stations at the national level through NETA (National Educational Television Association), and

Table 2-3. Overview of Target Outreach Audiences and Outreach Method

Audience	General/Site-Specific Outreach Materials	Communication Methods		Basis for Outreach Assessment
		One-Way	Two-Way	
General Public/ Regionwide	*General*: Fact sheets, posters, DVDs, Web pages, Atlas	Product dissemination, press releases and articles, television broadcasts, Web site	–	Visitor interaction with Web site
Stakeholders in Project Areas	*Site specific*: Fact sheets, posters, Web pages	Product dissemination, press releases and articles, Web site	One-on-one and small group meetings; community meetings	Audience feedback
Select Communities	*General*: Fact sheets, posters, DVDs, Web pages, Atlas	Product dissemination, press releases and articles, Web site	–	–
Partners	Reports, Fact sheets, posters, Web pages	Product dissemination, Web site	One-on-one/ small group meetings	Web site referrals
Educators	*General*: Fact sheets, posters, DVDs, Web pages, Atlas	Product dissemination, Web site	Interactive presentations at meetings, workshops, and classes	Audience feedback, Web site campaigns
Opinion Leaders	*General*: Fact sheets, posters, DVDs, Web pages Atlas	Product dissemination, Web site	One-on-one/small group meetings, Conferences	Audience feedback

individual stations can broadcast shows for up to 3 years after downloading them (NETA does not provide information regarding the number of downloads that occur; rather, use data are gleaned from other means of tracking).

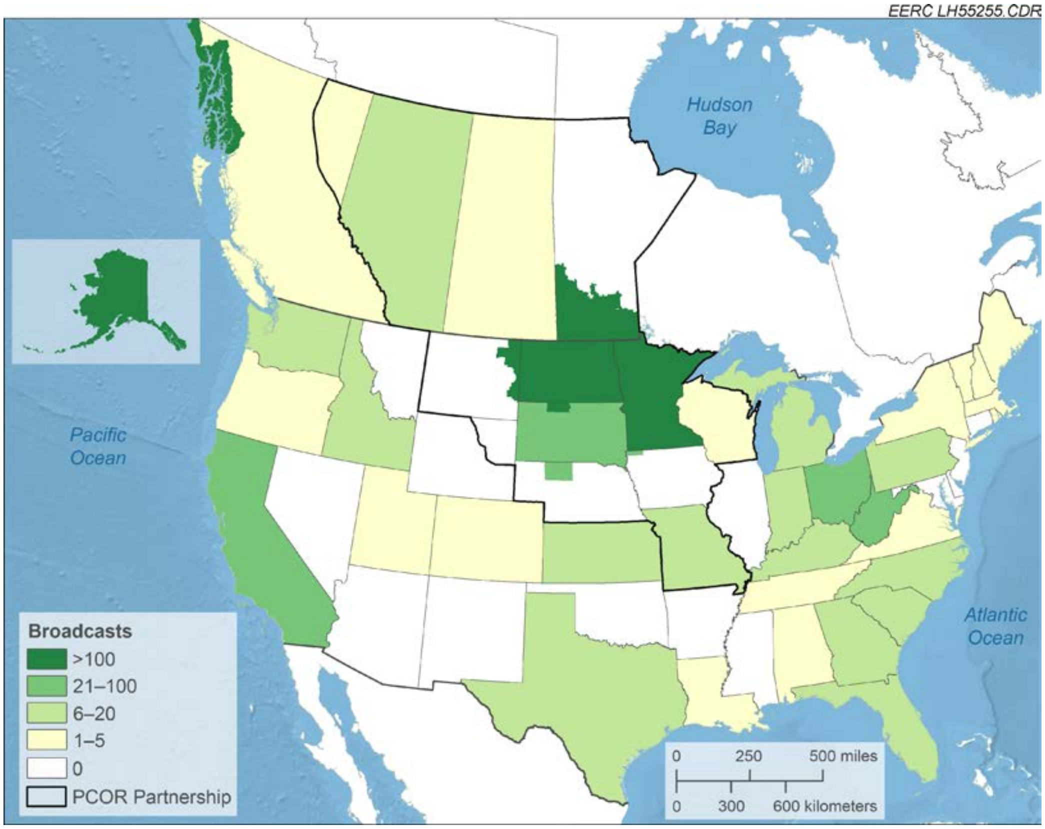

Figure 2-4. Map showing outreach coverage of documentaries prepared during Phase III of PCOR Partnership, which is outlined with a heavy black border. Documentary broadcasts occurred 265 times in the PPB region that includes North Dakota and adjacent areas shown in dark green. Darker colors represent a greater frequency of broadcasts.

Educators

With respect to educators, the outreach team presented to approximately 200 teachers on an annual basis and provided them with packets of materials including a CCS presentation (for use in the classroom), lesson plans, DVDs of documentaries, and a copy of the regional atlas of CO_2 storage resources in the PCOR Partnership region. Major venues for these outreach activities included the annual Lignite Energy Council teacher workshop (~120 teachers) and PPB's Teacher Training Institutes (TTI; ~60 teachers). As a result of these efforts, presentations and outreach materials were provided to more than 1600 educators during Phase III project activities, representing 389 school districts in eight states and one Canadian province (Figure 2-5). In North Dakota, 86% of school districts were represented by the teachers who attended presentations and received outreach packets. In addition, the partnership worked with PPB's education services to engage master teachers to provide a review of partnership outreach materials for use by educators and to foster the development of the 15 CCS-related classroom activities resulting from the TTIs, all of which were available through the PPB Web site.

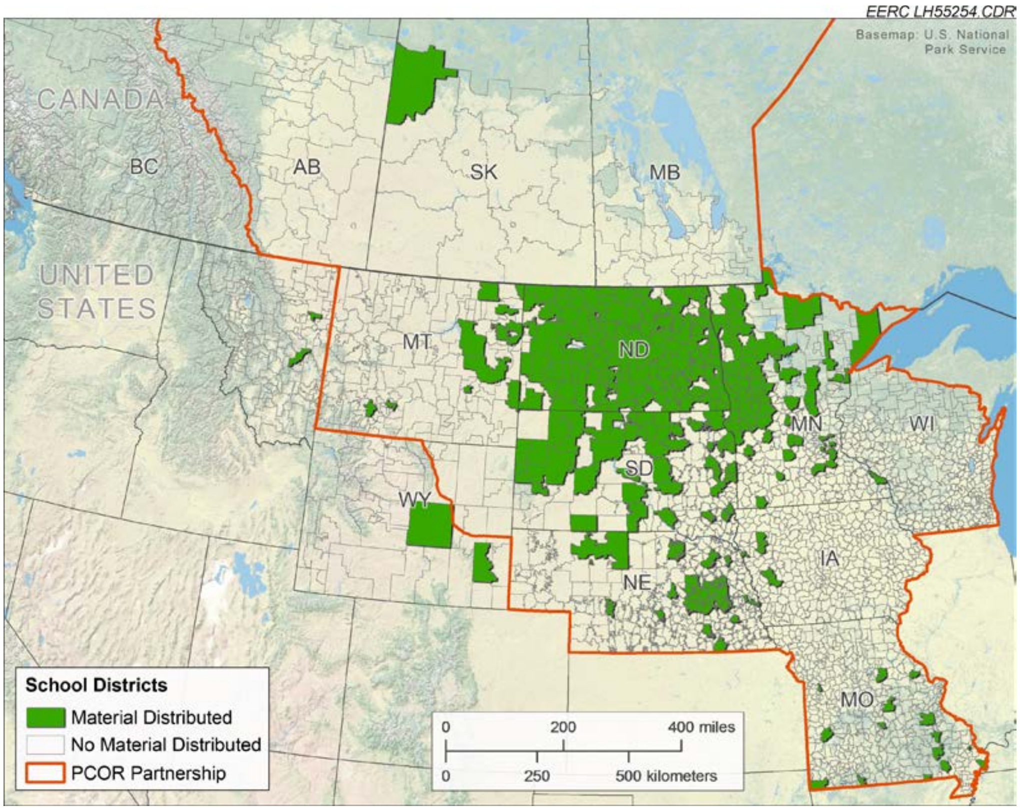

Figure 2-5. Map showing the distribution of the 389 school districts represented by the teachers who received PCOR Partnership presentations and outreach materials during Phase III of the project.

Libraries

To complete regional outreach efforts, representatives of the PCOR Partnership attended library conventions at the state (North Dakota Library Association, 2011, 2012, and 2014) and regional level (ten-state Mountain to Prairie Library Association in 2012). As a result, outreach materials, including documentary DVDs, regional atlases of CO_2 storage resources in the PCOR Partnership, and outreach posters were placed in 217 libraries across six states and one Canadian province (Figure 2-6).

REGIONAL OUTREACH PICTURE

Efforts were made to build a regional picture of the distribution and relationships of the individual outreach components that were conducted during Phase III to each other as well as to CCS infrastructure and potential CCS development areas. Figure 2-7 illustrates the summary outreach “score” resulting from this effort at the county (United State) or rural municipality level (Canada) based on responses to six questions: 1) Is the area a source of Web visits? 2) Does it have PCOR Partnership outreach materials in a library? 3) Were there documentary telecasts viewed

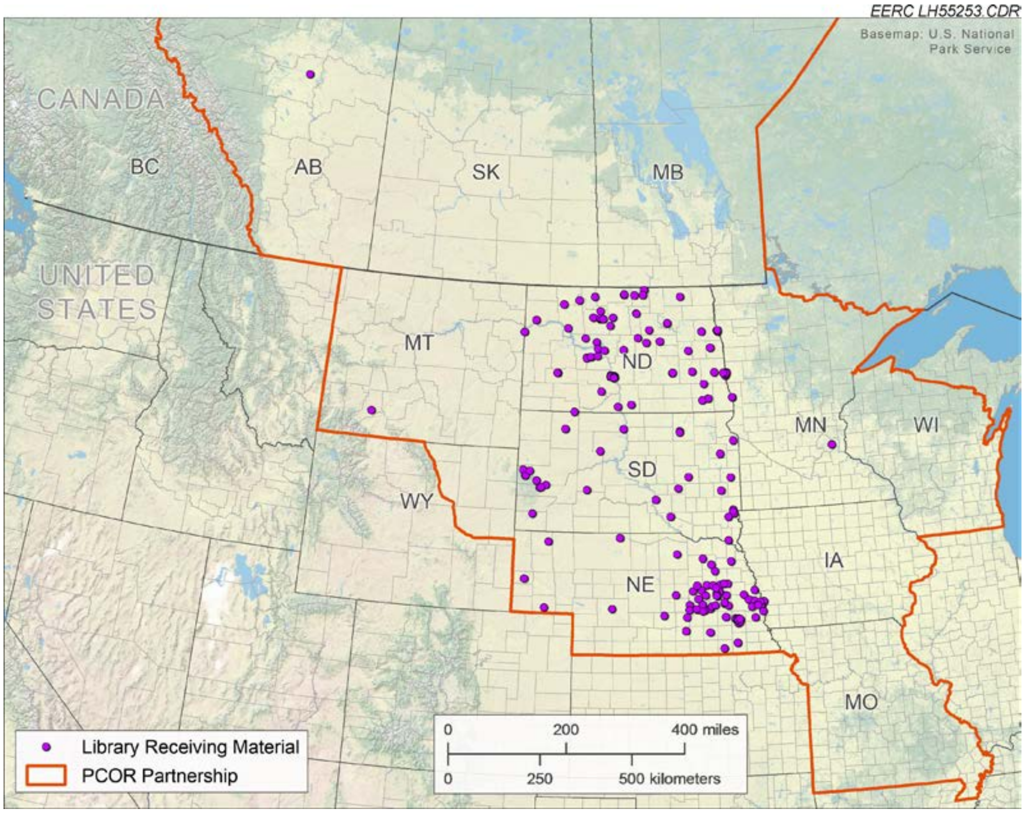

Figure 2-6. Map showing the distribution of the 217 libraries in the PCOR Partnership region that received outreach materials during Phase III.

within the area? 4) Were outreach materials provided to an educator in the area? 5) Was there any press coverage about the PCOR Partnership and/or PCOR Partnership projects in the area? and 6) Was there a CCS project in the area resulting in engagement with local audiences by the PCOR Partnership Program or by a CCS operator who was a PCOR Partnership member? As might be expected, scores are highest in North Dakota as well as adjacent areas of Montana, South Dakota, and Minnesota, reflecting the relatively high number of documentary telecasts in PPB's broadcast region (North Dakota, northwest Minnesota, and southern Manitoba), the number of school districts represented by teachers who attended teacher workshops and received PCOR Partnership materials and presentations, and the location of libraries that acquired materials at regional library conferences attended by PCOR Partnership outreach representatives.

COLLABORATION AND INFORMATION SHARING

The PCOR Partnership outreach team took an active role in the Outreach Working Group (OWG) of the Regional Carbon Sequestration Program (RCSPs) of DOE. In addition to participation in monthly conference calls, the PCOR Partnership outreach team was active in 1) development of DOE's outreach best practices documents (U.S. Department of Energy National Energy Technology Laboratory, 2009, 2017); 2) writing and reviewing papers for the OWG; and

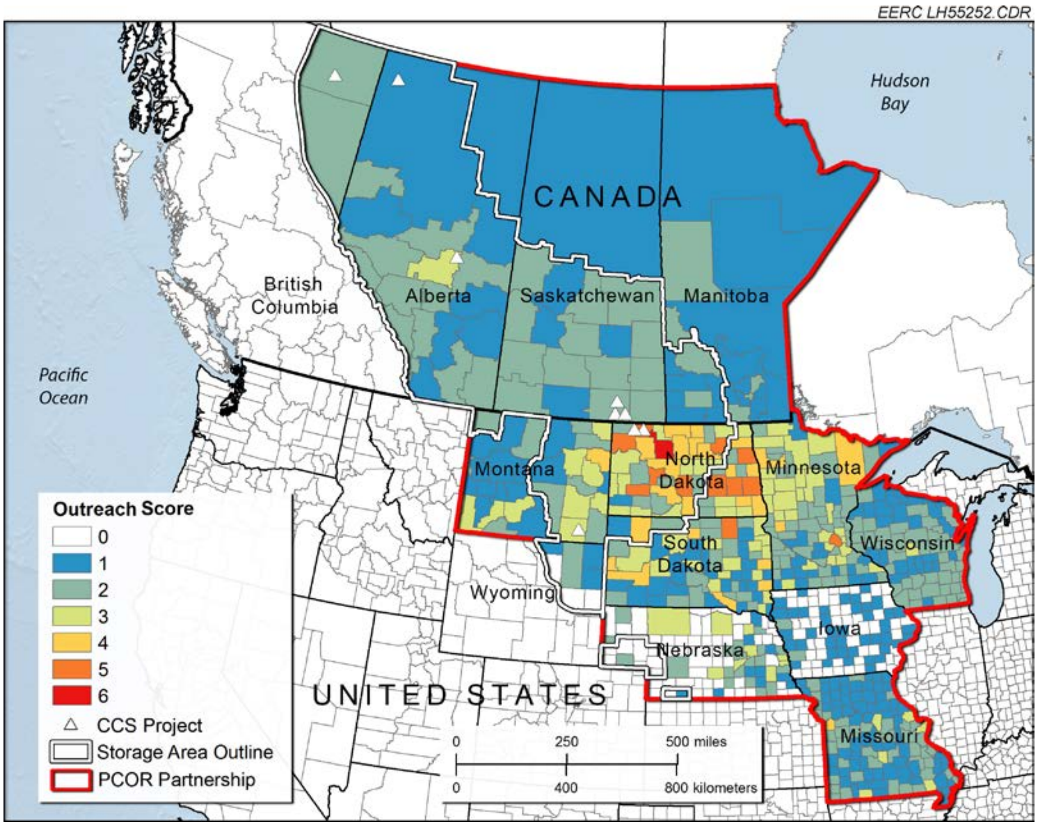

Figure 2-7. Phase III summary outreach score for the PCOR Partnership region at the county (United States) and rural municipality (Canada) levels. The PCOR Partnership is outlined in red and the areas with storage potential within the partnership are outlined in white. Hotter colors represent higher scores, indicating more overall outreach activities.

3) giving presentations and posters for the OWG at a number of venues, including the International Conference on Greenhouse Gas Control Technologies (GHGT-10 in Amsterdam, Netherlands [Daly and others, 2011a]; and GHGT-11 in Kyoto, Japan); the October 2011 Society of Petroleum Engineers (SPE) CCS forum in Faro, Portugal (Daly, 2011; Daly and others, 2011b); the February 2013 Global CCS Institute (GCCSI) outreach workshop at the Canadian Embassy in Washington D.C. (Daly and others, 2014); and in a variety of CCS meetings in the United States. The PCOR Partnership also took part in OWG workshops and provided editing and graphics support to the OWG on posters and papers.

As part of the outreach advisory panels for the Weyburn–Midale and Aquistore CCUS projects, the PCOR Partnership ensured that the first edition of DOE's Best Practices for Public Outreach (U.S. Department of Energy National Energy Technology Laboratory, 2009) was available to PTRC for use in the development of the Aquistore outreach plan. The PCOR Partnership coauthored a paper with PTRC on the contrast between public outreach for enhanced oil recovery (EOR)-based projects and dedicated storage projects, presented at GHGT-13 in Lausanne, Switzerland (Sacuta and others, 2017). The partnership also served as a peer reviewer for the outreach resource document, "What Happens When CO_2 Is Stored Underground: Q&A

from the IEAGHG Weyburn–Midale CO_2 Monitoring and Storage Project" (Global CCS Institute/ Petroleum Technology Research Centre, 2014) and subsequently took part in a workshop at PTRC in Regina, Saskatchewan, to present comments and discuss the path forward. The PCOR Partnership also facilitated PTRC's presentation to the OWG regarding its public outreach experience with respect to the false reports of a CO_2 leak at Weyburn in Canada.

DEVELOPMENT AND APPLICATION OF OUTREACH BEST PRACTICES

In May 2009, the PCOR Partnership submitted a best practices manual for its outreach based on its experiences and lessons learned (Daly and others, 2009). This document defined and described 20 best practices organized under six major headings (e.g., Outreach Approach, Regional Outreach, Project-Level Outreach, Tracking and Impact, Product Review and QA/QC, and Partnership Building). This partnership-level perspective on outreach best practices was provided as input into the creation of outreach best practices manual of the RCSP Initiative (U.S. Department of Energy National Energy Technology Laboratory, 2009, 2017).

The relationship of outreach to project management, the use of geographic information system for outreach, and the tracking of outcomes of outreach activities represent areas for future development that are of great interest to the PCOR Partnership (Daly and others, 2018). The goal is to make findings in these areas available to future carbon capture, utilization, and storage projects in the region.

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APPENDIX 3

TASK 3 – PERMITTING AND NATIONAL ENVIRONMENTAL POLICY ACT (NEPA) COMPLIANCE

TASK 3 – PERMITTING AND NATIONAL ENVIRONMENTAL POLICY ACT (NEPA) COMPLIANCE

INTRODUCTION

Task 3 of Plains CO_2 Reduction (PCOR) Partnership Phase III was focused on confirming the environmental acceptability of the two Phase III demonstration projects, i.e., the Bell Creek oil field in Powder River County in southeastern Montana (Bell Creek Project) and the Fort Nelson natural gas-processing plant, situated near Fort Nelson, British Columbia, Canada (Fort Nelson Project). For both projects, this effort comprised the completion of an environmental questionnaire, which provided the U.S. Department of Energy (DOE) with the information necessary to determine the required level of NEPA review and documentation, along with a compliance assessment of the permits required for the conduct of the tests. However, it should be noted that the Fort Nelson Project is under the jurisdiction of the province of Alberta, Canada, and the NEPA requirements of the United States do not apply to the Fort Nelson Project; rather, completion of the questionnaire was required by DOE as a form of environmental due diligence. In addition, the EERC also identified, tracked, and commented on evolving federal, provincial, and state legislation and regulations for CO_2 storage and transportation in both the United States and Canada. Lastly, the PCOR Partnership was actively engaged with other technical and policy organizations that were also participating in this legislative/regulatory arena.

NEPA COMPLIANCE AND PERMITTING OF THE PHASE III DEMONSTRATION TESTS

Both of the Phase III demonstration tests were involved with ongoing commercial operations of Spectra Energy and Transmission (Fort Nelson Project) and Denbury Resources (Bell Creek Project). In both cases, the proposed Phase III field-based activities were limited to monitoring, verification, and accounting (MVA) efforts such as drilling of monitoring wells and data collection, which resulted in minimal additional environmental consequences for the ongoing operations of the site operator. As noted above, even though the NEPA requirements of the United States did not apply to the Fort Nelson Project, a DOE environmental questionnaire was completed for both projects. Based on the results of the questionnaires, the EERC determined that the Bell Creek Project qualified for a categorical NEPA exclusion and did not require the completion of a formal NEPA environmental assessment (EA). The Fort Nelson Project also would have qualified for a categorical NEPA exclusion had it been subject to the requirements of NEPA.

Following these determinations, the Energy & Environmental Research Center (EERC) prepared regulatory permitting action plans to assist the commercial partners in meeting their respective regulatory requirements (Botnen and others, 2011a). The action plans provided background information on each project and described the regulatory and permitting steps that were necessary for the EERC and its partners to conduct each of the demonstration tests. Additionally, relevant federal, state, and provincial regulatory summaries were included as part of the plan.

The EERC continued to assist its commercial partners with meeting the permitting and reporting requirements of their respective provincial/state jurisdictions, i.e., the British Columbia Oil and Gas Commission (BCOGC) (Fort Nelson Project) and the Montana Board of Oil and Gas Conservation (MBOGC) (Bell Creek Project). In addition, the EERC was actively involved with monitoring the evolving MVA-related federal regulations of the United States and Canada. The more salient of these federal permitting/reporting support efforts are listed below:

- Reviewed the proposed U.S. Environmental Protection Agency (EPA) requirements and participated in EPA-sponsored training Webinars for the reporting of greenhouse gas (GHG) emissions ("Mandatory Reporting of Greenhouse Gases and Federal Requirements under the Underground Injection Control [UIC] Program for Carbon Dioxide Geologic Sequestration Wells") (U.S. Environmental Protection Agency, 2010).

- Completed an analysis of the MVA program of the Bell Creek Project in association with the reporting requirements under the EPA Mandatory Greenhouse Gas Reporting Rule, Subpart RR – Geologic Sequestration of Carbon Dioxide.

- Conducted a review of the evolving permit requirements of EPA for the geologic storage of carbon dioxide, and provided four updates of this review, all of which were submitted as project deliverables (Botnen and others, 2011b, 2013; Wilson and others, 2015, 2016, 2018).

- Reviewed and provided comments on the draft standard for the geologic storage of CO_2 of the Canadian Standards Association (CSA), a nonregulatory advisory organization to regulatory and industry (2012).

- Reviewed and provided comments on a number of EPA guidance documents which were developed to follow the sequence of activities that an owner or operator is required to perform over time at a proposed and permitted geologic storage site:

    1. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Site Characterization Guidance (May 2013)
    2. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Area of Review and Corrective Action Guidance (May 2013)
    3. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Testing and Monitoring Guidance (March 2013)
    4. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Project Plan Development Guidance (August 2012)
    5. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Construction Guidance (May 2012)
    6. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Program: Financial Responsibility Guidance (July 2011)
    7. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance (December 2016)

8. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators (September 2016)
9. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Permitting Authorities (March 2013)
10. Geologic Sequestration of Carbon Dioxide: UIC Program Class VI Well Primacy Application and Implementation Manual (April 2014)

The EERC routinely conveyed the results of these efforts to commercial partners through a combination of written summaries, Webinars, and/or knowledge-sharing workshops.

MONITORING/PARTICIPATION IN CARBON CAPTURE AND STORAGE (CCS) LEGISLATIVE AND REGULATORY DEVELOPMENT EFFORTS

The EERC interacted with relevant state and provincial regulatory agencies within the PCOR Partnership region, as well as representatives of the federal regulatory agencies of the United States and Canada to develop an understanding of the current and evolving legislative and regulatory frameworks related to CO_2 capture, utilization, and the geologic storage of CO_2 (CCUS).

Regulatory Roundup Meetings

The centerpiece of this effort was the organization and execution of annual regulatory roundup meetings. Representatives of each state and province of the PCOR Partnership as well as relevant federal regulatory agencies of the United States and Canada were invited to these meetings. During these meetings, representatives of the participating jurisdictions provided an update of their regulatory, legislative, and policy activities related to CCUS. In addition, the meetings also provided an opportunity for participants to refresh working relationships across the technical and regulatory policy interface, discuss technical and regulatory policy items of common interest related to the CCUS industry, and share regulatory approaches as well as legislative and regulatory lessons learned. The EERC initiated the regulatory roundup meeting on June 16 and 17, 2009, in Deadwood, South Dakota, which was followed annually by six other meetings during the period from 2010 through 2015, as listed below:

- 2nd annual meeting: July 21–22, 2010 (Deadwood, South Dakota).
- 3rd annual meeting: June 29–30, 2011 (Bismarck, North Dakota).
- 4th annual meeting: July 30 – August 1, 2012 (Deadwood, South Dakota).
- 5th annual meeting: July 30–31, 2013 (Deadwood, South Dakota).
- 6th annual meeting: June 24–25, 2014 (Deadwood, South Dakota).
- 7th (final) annual meeting: July 22–23, 2015 (Deadwood, South Dakota).

With the exception of the first annual meeting, minutes were prepared for all of the regulatory roundup meetings. Some of the more significant legislative and regulatory activities and developments that were highlighted during these meetings and/or discussed with regulators during subsequent interactions are provided below, by year:

2010

- The PCOR Partnership announced its involvement in the Pipeline Transportation Task Force (PTTF) of the Interstate Oil and Gas Compact Commission (IOGCC) and the next phase of IOGCC efforts, which were focusing on regulation of the storage side of CO_2 injection.

- Alberta passed the Carbon Capture and Storage Funding Act in 2009. This act created a $2 billion CCS funding program to enable the implementation of large-scale CCS projects in Alberta. $1.3B of this fund was allocated to two commercial-scale projects: 1) Shell Quest (oil sands) and 2) the Alberta Trunk Carbon Line, or ATCL (bitumen refinery and fertilizer plants).

- Alberta's Carbon Capture and Storage Funding Regulation authorized spending for the Regulatory Framework Assessment (RFA) as well as for education and research regarding CCS projects. The RFA was to provide a process to ensure the necessary regulations are in place before full-scale CCS projects started operations.

- Alberta passed the Carbon Capture and Storage Statutes Amendment Act to address two key barriers preventing CCS from moving forward in Alberta: 1) long-term liability for CO_2 stored underground and 2) pore space access. This act allows the provincial government to assume long-term liability for storage sites after the sites have been properly closed and the operators have demonstrated through long-term monitoring that the stored CO_2 is stable. The act also makes it mandatory for CCS operators to contribute to the Post-Closure Stewardship Fund. The provincial government will use this fund for ongoing monitoring and any required maintenance and remediation. The act also resolved the uncertainty associated with pore space ownership by making the decision that the government of Alberta would assume pore space ownership as well as the long-term liability of the pore space.

- Saskatchewan amended the 1998 Pipelines Act in 2009 to cover CO_2 pipelines for non-oil-and-gas operations.

2011

- The PCOR Partnership highlighted its efforts to monitor the latest federal and state CCS regulatory developments (e.g., EPA's Mandatory Reporting of Greenhouse Gases Rule [MRR] and Class VI rules) and its participation in a) the Presidential Interagency Task Force on CCS and b) IOGCC's Geological Sequestration Task Force.

- Alberta passed the Carbon Sequestration Tenure Regulation, establishing a process for companies to follow to obtain tenure or lease rights for pore space for the purpose of evaluating the suitability of a potential storage site or to store CO_2.

- Saskatchewan amended the Oil and Gas Conservation Act (OGCA) to expand its powers and oversight for the storage of CO_2 and other greenhouse gases. For example, the term "non-oil-and-gas waste" was replaced with "non-oil-and-gas substance" to clarify the scope to include substances from the CCS industry, and the minister was granted the authority to approve or refuse a CO_2 storage plan. Examples of other applicable parts of the regulation to CO_2 storage included well testing and measurement, data requirements, and records and reporting requirements.

2012

- The PCOR Partnership noted its participation in the review of several guidance documents that were generated by EPA, including guidance that targeted the transition of Class II to Class VI wells and its tracking of the development of the comprehensive CCS regulations of CSA, which were completed in fall 2012 (Canadian Standards Association, 2012).

- The efforts of the International Organization for Standardization (ISO) were reviewed and discussed to develop a standard to address capture and sequestration in saline aquifers and transportation, and crosscutting topics such as risk assessment were reviewed and discussed.

- The PCOR Partnership also tracked and discussed other important legislative/regulatory items, including:

  – Proposals regarding 45Q tax credits.
  – A study completed by the Clinton Initiative in coordination with the Midwest Governor's Association (MGA) and the Great Plains Institute regarding the CO_2 EOR potential of the MGA region.
  – CO_2 EOR initiatives to address residual oil zones.
  – NEORI (National Enhanced Oil Recovery Institute) efforts to develop incentives to accelerate commercial development of CCS and CO_2 EOR.
  – Activities of IOGCC, which included 1) two key study reports ("Carbon Capture and Storage: A Regulatory Framework for States, Summary of Recommendations" and "Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces" (Interstate Oil and Gas Compact Commission, 2005, 2007), one of which included a model statute and model rules and regulations for the geologic storage of CO_2, which was later updated during a biennial review; 2) the initiation of a third phase of work in October 2012, which augmented the previous efforts by focusing on the operational and postoperational liability of CCS operations and the creation of Operational and Post-Operational Liability Subgroups that anticipated a final report in September 2013; and 3) teaming with the Groundwater Protection Council (GWPC) to form FracFocus, which was focused on disclosure of the chemicals used in fracturing fluids.
  – Initial CCS legislation drafted by the North Dakota Industrial Commission (NDIC) in 2009 (North Dakota Century Code 38-22) based on the IOGCC model statute, as well as the administrative rule making which proceeded in April 2010 (North Dakota Administrative Code 43-05-01).
  – Submission of a draft application on January 19, 2012, by the state of North Dakota to secure primacy of the Class VI rules released by EPA in December 2010.

- British Columbia released its Natural Gas Strategy, which focused specifically on the development of a new LNG sector. This strategy committed the government to promote the use of CCS by completing the development of a CCS regulatory framework.

- Following the amendment of the Oil and Gas Conservation Act, Saskatchewan passed its Oil and Gas Conservation Regulations, which provided greater oversight of carbon storage.

<u>2013</u>

- IOGCC and GWPC introduced the States First Initiative, which urged states to take control of future energy developments within their borders.

- North Dakota continued developing CCS legislation and regulations, including amendments to the rule making which became effective in April 2013, following the publication of the Class VI rules by EPA in December 2010.

- North Dakota submitted a primacy application for the Class VI rules of EPA on June 21, 2013.

- In December, EPA released guidance regarding the transition of Class II wells to Class VI wells.

- The North Dakota Pipeline Authority (NDPA) initiated an investigation of establishing multiuse easements for pipelines and concepts for constructing state-supported pipelines.

- Alberta completed the Regulatory Framework Assessment in December 2012, and a final report was provided to the Alberta Energy Minister in 2013 that included 25 actionable items for consideration by the government of Alberta.

- Manitoba enacted the Climate Change and Emission Reduction Act.

<u>2014</u>

- IOGCC Phase III project results were reviewed and discussed, which focused on closure and postclosure regulatory issues. The Phase III project results are summarized in a report, "Guidance for States and Provinces on Operational and Postoperational Liability in the Regulation of Carbon Geologic Storage," which was published in September 2014.

- The PCOR Partnership presented and discussed a time line representing approval of the North Dakota Class VI primacy application as shown below:
  - June 21, 2013 – Primacy application was submitted.
  - July 10, 2013 – EPA Region 8 returned the memorandum of agreement (MOA) to North Dakota with comments. These comments were focused on advanced notification of emergencies and Section 1431 of Solid Waste Disposal Act (SWDA: Part D – Emergency Powers). Revised changes in language were accepted.
  - August 30, 2013 – EPA Region 8 proposed additional revisions to MOA language.

- September 17, 2013 – The North Dakota Attorney General contacted Region 8 and worked out revised language.
- October 29, 2013 – The North Dakota finalized the MOA with EPA Region 8.
- January 18, 2014 – Changes to the Code of Federal Regulations (CFR), 40 CFR§147.1751 (State-Administered Program—Class I, III, IV, and V Wells) were proposed that added Class VI wells to the jurisdiction of North Dakota. April 25, 2014 – EPA Region 8 approved proposed changes to 40 CFR.

- A cross-government team in British Columbia drafted a CCS regulatory framework, which included the oil and gas regulators of the province. The framework provided a robust regulatory model that addresses key CCS issues such as reservoir selection, security of CO_2 storage, monitoring, and long-term liability. The ultimate goal of this framework is to ensure that a regulatory regime is in place for commercial CCS projects to proceed by addressing regulatory barriers to CCS projects and providing regulatory certainty to CCS developers.

<u>2015</u>

- PCOR Partnership representatives reviewed the EPA clarification memo dated April 23, 2015, regarding the transition of Class II to Class VI injection wells. Within this memorandum, EPA confirmed its preference for the state to take responsibility for certifying incidental storage of CO_2 during EOR.

- The Environment and Safety Committee of IOGCC met and discussed the transition from Class II to Class VI wells. The PCOR Partnership provided a draft resolution to the committee chairman, which was based on the April 25, 2015, letter of EPA that more clearly quantified the criteria and/or process for determining the transition of a Class II CO_2 enhanced oil or gas recovery project to a Class VI geologic storage project.

- British Columbia passed the Natural Gas Development Statutes Amendment Act, which provided the first round of amendments to the Petroleum and Natural Gas Act and the Oil and Gas Activities Act to enable CCS.

- The EERC notified attendees that it would move forward with a regulatory white paper regarding the permitting process for a CCS/CCUS project (“Regulatory Perspective Regarding the Geologic Storage of Carbon Dioxide [CO_2] in the PCOR Partnership Region”) plus one or more updates.

At the conclusion of this task in March 2018, the final approval of the North Dakota primacy application was published in the Federal Register on April 24, 2018. In addition, the final task report, “Regulatory Perspective Regarding the Geologic Storage of Carbon Dioxide (CO_2) in the PCOR Partnership Region,” (Wilson and others, 2017) was submitted on January 31, 2017, and subsequently approved for publication by the DOE National Energy Techology Laboratory (NETL).

Review of Legislative and Regulatory Documents

In addition to the specific legislative/regulatory documents that were previously highlighted, the EERC reviewed and provided comments on other legislative and regulatory documents and/or presentations related to the geologic storage of CO_2 that were published throughout Phase III of the project. A list of several of these key publications, including the publishing organization and date of publication, are provided in Table 3-1.

Based on these document reviews, the EERC routinely updated the Phase III commercial partners regarding both legislative and regulatory developments in the United States and Canada, as well as international countries/organizations.

Interactions with IOGCC and Other Groups Active in Development of CCS Legislation/Regulations

As summarized above and documented in the minutes of the regulatory roundup meetings, the EERC interacted extensively with IOGCC during the execution of this task by actively coordinating with the IOGCC Carbon Capture and Geologic Storage (CCGS) Task Force to address issues relating to 1) legal and regulatory infrastructures for storage of CO_2 in geologic structures, 2) pipeline transportation of CO_2, and 3) operational and postoperational liabilities that remain as barriers to the establishment of state and federal legal and regulatory frameworks for CCUS. Because of its prominent role in the PCOR Partnership Program, more details regarding IOGCC interactions as well as interactions with other organizations active in the regulatory/legislative CCS process are provided in the remainder of this section.

IOGCC

As demonstrated by North Dakota, IOGCC has been a major force in the development of legislative and regulatory approaches for the geologic storage of CO_2 that can be used by states as a template for securing primacy of the federal rules for the CCS industry. Participation of the EERC in the legislative and regulatory activities of the IOGCC is briefly summarized below:

- The IOGCC PTTF was formed in May 2009 to undertake the scoping of the issue of CO_2 pipeline transportation on behalf of states. As part of that effort, it developed a draft interim regulatory framework for the pipeline transportation of CO_2. The EERC participated in the review of that task force report.

- The EERC participated in the biennial update of the Phase 2 report of the IOGCC CCGS Task Force, "Storage of Carbon Dioxide in Geologic Structures: Legal and Regulatory Guide for States and Provinces," which included a model statute and model rules and regulations for the geologic storage of CO_2. The state of North Dakota later used the model statute as a basis for the development of its legislation for the geologic storage of CO_2 (North Dakota Administrative Code § 43-05-01 [Geologic Storage of Carbon Dioxide]).

Table 3-1. List of Additional Legislative/Regulatory Publications Reviewed by the PCOR Partnership

Document Title	Publishing Organization/Author	Date of Publication
Canadian Environmental Protection Act	Ministry of Environment – Canada	1999 (last amended June 2016)
Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide Sequestration Wells: Notice of Data Availability and Request for Comment	EPA	August 31, 2009
North Dakota Administrative Code § 43-05-01 (Geologic Storage of Carbon Dioxide)	NDIC	Effective April 1, 2010; amended effective April 1, 2013
Proposed rules regarding Clean Air Act permits for sources of greenhouse gas emissions under the Prevention of Significant Deterioration (PSD) Program;	EPA	August 12, 2010
Final Rule for Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells	EPA	November 2010
Carbon dioxide capture, transportation, and geological storage	ISO/Technical Committee (TC) 265	2011
CO2QUALSTORE Guideline for Selection, Characterization, and Qualification of Sites and Projects for Geological Storage of CO_2	Det Norske Veritas/Michael Carpenter	July 2011
Procedures for the permitting of seismic exploration on Federal lands	Bureau of Land Management	December 1, 2011
Developing a Small-Scale CO_2 Test Injection: Experience-To-Date and Best Practice	IEA Greenhouse Gas R&D Programme	October 2013
SaskPower CCS Global Consortium – Bringing Boundary Dam to the World	SaskPower	2013
Canadian Update – Select CCS Regulatory Developments	International Energy Agency	2014
Final rules regarding the Resource and Conservation Recovery Act exemption for CCS	EPA	March 4, 2014
Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units	EPA	June 18, 2014
Carbon Capture and Storage Regulatory Policy – Consultation Summary Report	British Columbia – Ministry of Natural Gas Development	October 2014
A Review of Existing Best Practice Manuals for Carbon Dioxide Storage and Regulation	Global CCS Institute	October 10, 2014
Canadian Update: Select CCS Regulatory Developments	Natural Resources Canada (presented at 6th IEA Regulatory Network Meeting)	May 27, 2014
The Quest for Less CO_2: Learning from CCS Implementation in Canada – A Case Study on Shell's Quest CCS Project	Shell International B.V.	2015
Memorandum clarifying the transition of Class II wells to Class VI wells	EPA Office of Groundwater	April 23, 2015
Regulation of CO_2 EOR and CCS in Saskatchewan	Province of Saskatchewan (presented at 2015 SaskPower CCS Symposium)	September 10, 2015
State of North Dakota Underground Injection Control Program; Class VI Primacy Approval	EPA	April 24, 2018

- The third phase of IOGCC efforts, which augmented the previous efforts by focusing on the operational and postoperational liability of CCS operations, was initiated on October 4, 2012, with the creation of two subgroups, i.e., the Operational and Post-Operational Liability Subgroups. The EERC participated in these subgroups, which were led by Kevin Bliss Consulting, and produced a final project report in September 2014 (Interstate Oil and Gas Compact Commission, 2014). Results of this effort highlighted the continued need for liability coverage after postclosure, even after financial assurance is released, since liability is not released under the Safe Drinking Water Act (SDWA). Possible solutions to this problem were identified and included an amendment of federal statutes and/or the assumption of this liability by the states. Two of the more important recommendations from this effort are: 1) states will need to play a role in the development of geologic storage projects, including resource management, providing for remediation of abandoned sites after release of financial assurance under Class VI regulations, and determining the level of long-term liability (e.g., monitoring, remediation, level of liability assumption) and 2) states should seek Class VI primacy to ensure that the interests of the state are protected (e.g., assure that CO_2 EOR transition requirements of the Class VI rule do not adversely impact existing or future CO_2 EOR projects).

- The EERC participated in a meeting of the IOGCC Environmental and Safety Committee on May 19, 2015, and provided a draft resolution to the committee chairman that more clearly quantified the criteria and/or process for determining the transition of a Class II CO_2 enhanced oil or gas recovery project to a Class VI geologic storage project based on the memorandum issued by the EPA Office of Groundwater on April 25, 2015.

Other Groups Involved with Development of CCS Legislation/Regulations

In addition to IOGCC, the EERC interacted with several of the major actors involved in development of CCS legislation and regulation. Details of these interactions are too numerous to describe; however, a list of organizations that were engaged is presented in Table 3-2.

The EERC also reached out to several other legislative and regulatory stakeholders through numerous presentations at technical conferences around the world. These presentations are too numerous to list in this report but can be found in the progress reports that were filed every quarter with DOE throughout the duration of the project.

Table 3-2. List of Organizations Engaged During Execution of Task 3

Advanced Energy Technology Initiative, Illinois State Geological Survey
Alberta Energy – Electricity and Alternative Energy and Carbon Capture and Storage Division Alberta Energy Regulator Alberta Innovates
C2ES – Center for Climate and Energy Solutions
DOE National Labs such as Lawrence Berkeley National Laboratory and Pacific Northwest Laboratory
Enhanced Oil Recovery Institute, University of Wyoming
Environmental Defense Fund
Global CCS Institute
Groundwater Protection Council
International Energy Agency
Melzer Consulting, Inc.
NEORI
North America 2050 (NA2050): A Partnership for Progress – Sequestration Working Group
North Dakota's CO_2 Storage Work Group/Task Force
North Dakota Department of Mineral Resources, Oil and Gas Division
NDIC
North Dakota Petroleum Council
North Dakota Pipeline Authority
PCOR Partnership Partners, such as Eagle Operating, Aquistore, Praxair, Tundra Oil and Gas
President's Interagency Task Force on Carbon Capture and Storage
Regional Carbon Sequestration Partnership (RSCP) Outreach Working Group
Saskatchewan Ministry of the Economy
Saskatchewan and South Dakota Geological Surveys
SECARB and Other RCSPs
Shell Canada
Society of Petroleum Engineers
University of North Dakota School of Law
U.S. Carbon Sequestration Council
EPA

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APPENDIX 4

TASK 4 – SITE CHARACTERIZATION AND MODELING

TASK 4 – SITE CHARACTERIZATION AND MODELING

INTRODUCTION

Site characterization and modeling were performed at two demonstration sites that were selected for Phase III of the Plains CO_2 Reduction (PCOR) Partnership Program for the purpose of geologic characterization in preparation for geologic storage of CO_2. The two sites were 1) the Fort Nelson Gas Plant (FNGP) owned by Spectra Energy Transmission (SET) and 2) the Bell Creek oil field owned by Denbury Resources Inc. (Denbury). The primary technical activities that were performed comprised core sample and well log data acquisition, geochemical evaluations, geomechanical assessments, geophysical investigations, and geologic model construction.

FORT NELSON TEST SITE

The feasibility of a carbon capture and storage (CCS) project to mitigate CO_2 emissions produced by the FNGP was investigated as part of Phase III. FNGP is located near the town of Fort Nelson in northeastern British Columbia, Canada (Figure 4-1 left panel). The injection targets being considered consists of brine-saturated carbonate rocks (limestone and dolomite) of the Elk Point Group. The proposed injection zone is capped by 550 m of shale in the Fort Simpson and Muskwa Formations (Figure 4-2). The implementation of the Fort Nelson CCS project was projected to result in the storage of >2 million tonnes of CO_2 per year in a deep saline formation. The PCOR Partnership applied geologic characterization; modeling; risk assessment (RA), and monitoring, verification, and accounting (MVA) strategies using an integrated, iterative adaptive management approach to investigate the feasibility of the project. A technical team that included SET, the EERC, and others conducted a variety of activities to 1) determine the geological, geochemical, and geomechanical properties of the potential injection zones and key sealing formations in the vicinity of the injection site and 2) model the effects that large-scale injection of CO_2 may have on those properties as well as wellbore integrity. More specifically, SET and the PCOR Partnership collected baseline characterization data on the potential injection targets, sealing formations, shallow subsurface, and surface environments, including drilling of an exploratory well in the Fort Nelson area. Those data were used to create static petrophysical models of potential CO_2 storage reservoirs and conduct numerical simulation of potential injection scenarios. The Fort Nelson project also included efforts to determine baseline conditions of shallow groundwater resources in the vicinity of the c-61-E well location (see Figure 4-1, right panel). Unfortunately, limited site access caused by the Fort Nelson area terrain and climate conditions severely limited the collection of such data as part of the feasibility study. The baseline characterization data and modeling results were ultimately applied to a RA of potential operational scenarios. Lastly, even before an injection strategy had been finalized for the FNGP, a draft MVA plan for a hypothetical injection scheme was developed using assumptions that were based on the feasibility study efforts. Brief overviews of these characterization and modeling activities are provided below.

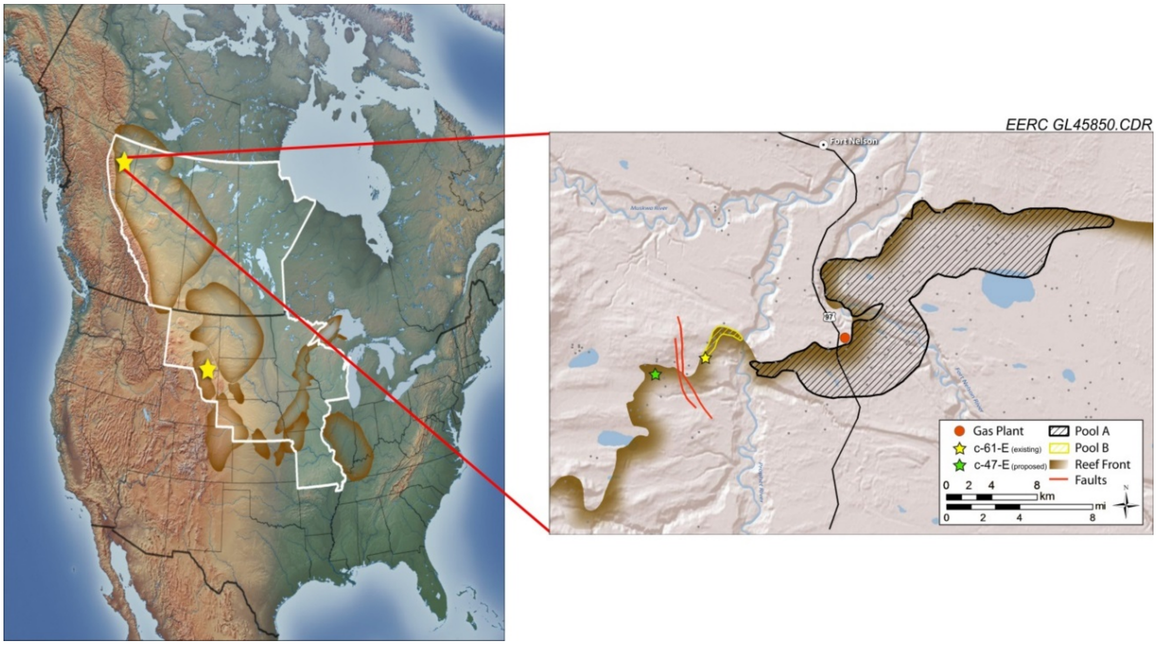

Figure 4-1. Map of the Fort Nelson project study area in British Columbia.

Site Characterization

Fort Nelson site characterization efforts included drilling of a test well (c-61-E) in 2010. The test well penetrated three potential reservoirs upon which SET conducted field-based drillstem tests (DSTs) to evaluate injectivity. Specifically, testing was performed on several porous sections within the Slave Point, Sulphur Point, and Keg River formations. These in situ tests provided valuable data that were used to estimate the permeability and injectivity of the potential reservoirs. Results of the exploratory drilling program, particularly the DST data and subsequent testing and analyses of cores and cuttings from the Sulphur Point and Upper Keg River formations, provided substantial evidence that these formations had sufficient injectivity to serve as CO_2 injection intervals for the Fort Nelson project.

Specific laboratory analyses that were conducted on potential sink formation rock samples included x-ray diffraction (XRD), x-ray fluorescence (XRF), quantitative evaluation of minerals (QEM), scanning electron microscopy (SEM), and SEM–energy-dispersive x-ray spectroscopy (EDS) for mineralogical and geochemical evaluations. Laboratory-based permeability and relative permeability testing was also performed on three core samples. Because the gas stream from FNGP was expected to include a small amount of H_2S, relative permeability testing was conducted using sour CO_2 (i.e., a mixture of 95% CO_2 and 5% H_2S). Relative permeability measurements conducted on these two core samples suggested that the processes of sour CO_2 displacing brine and brine displacing sour CO_2 were equally efficient and not likely to be subject to any significant degree of multiphase interference effects.

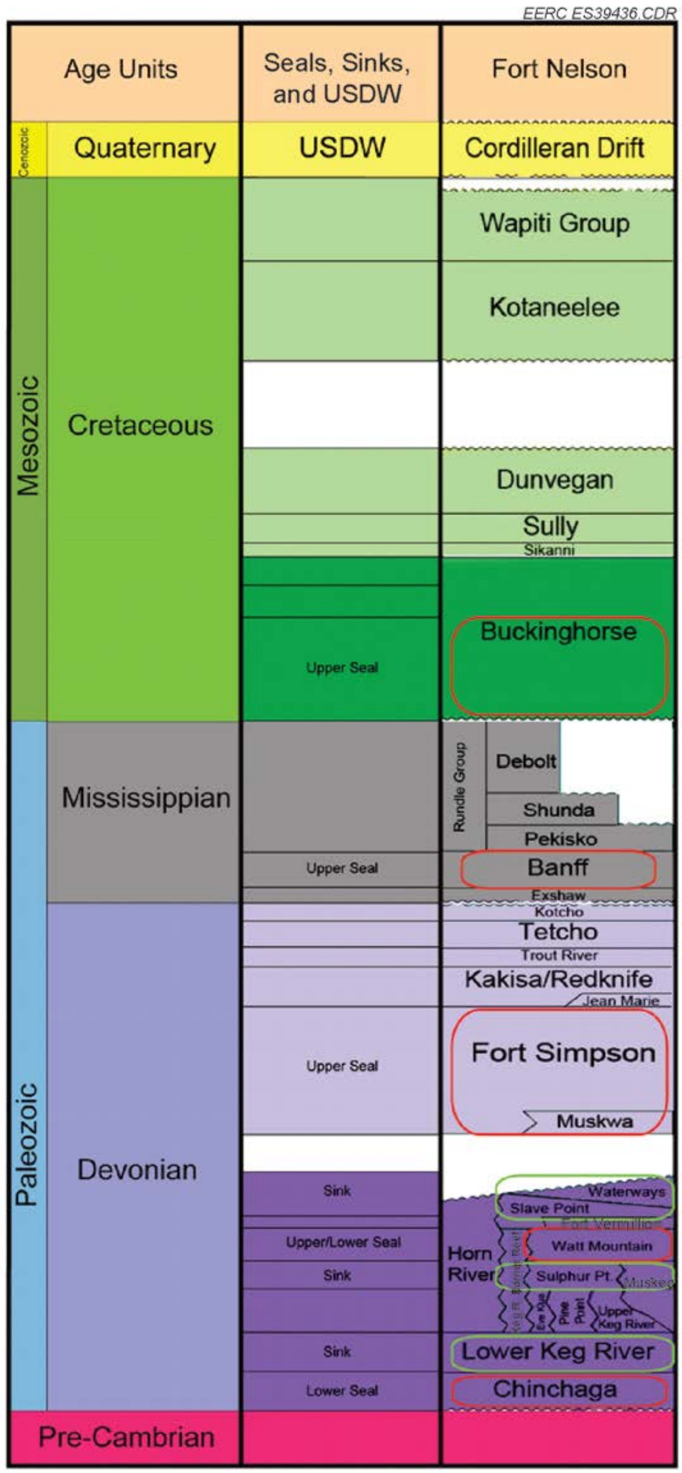

Figure 4-2. Stratigraphic column of the Fort Nelson area (Sorensen and others, 2014). The target injection zones are the Slave Point, Sulphur Point, and Lower Keg River formations. The overlying Fort Simpson and Muskwa shales (~550 m thick) represent an impermeable seal. (USDW is an underground source of drinking water.)

Reservoir Model Construction and Numerical Simulation

Extensive static and dynamic modeling activities have been conducted since 2008 for this CCS feasibility project. The regional petrophysical reservoir model covers a volume defined by 39 km × 67 km × 800 m, containing the injection formation and adjacent gas pools (Clarke Lake Slave Points A and B in Figure 4-1, right panel). The static model was developed iteratively over the course of the project. Specifically, three versions of the static model were created, with each version using newly acquired data to refine or build upon the version that preceded it. Data sets upon which the static models were based include publicly available historical well files, commercially available well data, acquisition of existing 2-D and 3-D seismic surveys, log analysis, core-testing results, and data generated by the drilling and testing of an exploratory well.

Numerical simulations included base case and initial scenario explorations, validations (history matching), optimization, and predictive simulations with sour CO_2 injection. Injection scenarios included injection of 50 and 100 million tonnes (Mt) of sour CO_2 over a period of 25 and 50 years, respectively. These scenarios were followed by 75 and 50 years of postinjection monitoring of the CO_2 plume to yield a total monitoring period of 100 years for both injection scenarios. The potential for CO_2 plume migration to adjacent gas pools (Clarke Lake Slave Points A and B) was also evaluated. These efforts produced a dynamic model that was validated through a history-matching process that involved historical gas and water production, water disposal data, and scattered bottomhole pressures (BHPs) in areas near the gas pools. The history-matching effort also improved the model by decreasing the uncertainty of several key geologic properties such as permeability, fault transmissibility, and vertical to horizontal permeability ratio (k_v/k_h anisotropy). Using this history-matched model, the storage capacity associated with two potential injection locations was assessed, which revealed that both injection locations had sufficient capacity to accommodate the target injection volumes.

Results of these modeling activities served as a critical component of the risk assessment program for the Fort Nelson CCS project. Specifically, modeling results played a primary role in the identification of risks related to injection operations, reservoir management, potential leakage of injected gas, and potential impacts on neighboring gas fields. By predicting the movement of the sour CO_2 plume and propagation of pressure away from potential injection sites, modeling results informed both selection of the final injection location and development of a cost-effective, site-specific MVA program. Figure 4-3 shows predicted plume extents over time for one of the potential injection scenarios that was modeled. The figure also shows suggested locations for monitoring locations in relation to the injection locations.

Summary of Findings

Results of characterization and modeling efforts suggested that the target storage reservoir has characterisitics that make it an exceptional candidate location for large-scale CCS. Potential storage formations (i.e., Devonian carbonate formations) included areas with excellent injectivity characteristics and an estimated storage capacity in the range of 140 million to 240 million metric tons of sour CO_2, sufficient to accept the CO_2 emissions of FNGP for several decades. The

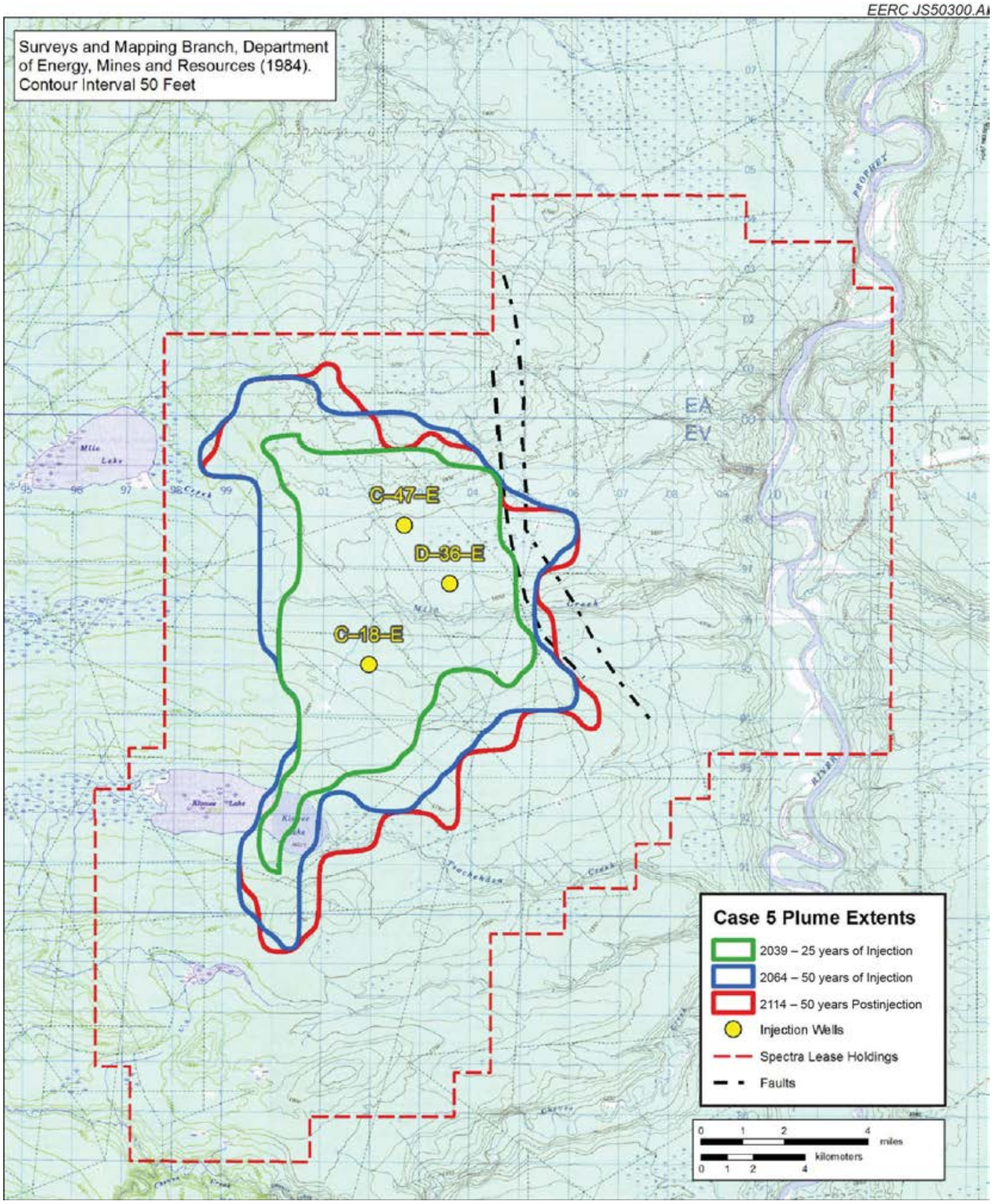

Figure 4-3. Map of predicted plume extents over time for one of the potential injection scenarios at the Fort Nelson site, showing also well locations for monitoring activities.

extremely low permeability, high geomechanical competence, and tremendous thickness (>500 m) of the overlying Muskwa and Fort Simpson shale formations indicated that they are excellent seals. While climate and terrain were expected to challenge deployment of some MVA technologies, it was determined that an effective MVA plan for both surface and subsurface environments colud be achieved with the application of proven monitoring approaches used by the oil and gas industry in the area.

More generally, results of the Fort Nelson Phase III feasibility study indicated that deep carbonate saline formations can serve as effective, high-capacity locations for large-scale geological storage of CO_2. However, the inherent heterogeneity and anisotropic characteristics of the rock properties of carbonate formations, including porosity and permeability distribution, make characterization of carbonate strata challenging and can lead to a high degree of uncertainty in the interpretation of results, especially prediction of both injectivity and storage capacity of a formation. Therefore, detailed rock characterization from multiple wells and correlation and integration of the data with other data sets (e.g., seismic surveys, hydrogeological studies) are critical to reducing that uncertainty to acceptable levels. At the same time, injection of CO_2 and its mobility in a deep carbonate saline formation are closely analogous to conventional oil and gas production operations. Therefore, standard practices, protocols, and workflows that are commonly applied in the oil and gas industry for site characterization and modeling should be sufficent for these sites and have the added advantage of being generally well understood and accepted by the regulatory community.

BELL CREEK TEST SITE

The original Phase III plans included the conduct of a large-scale demonstration project in an oil field in the Williston Basin. At the time the PCOR Phase III program was initiated, negotiations between an oilfield operating company and a commercial provider of CO_2 for the Williston Basin project were in progress, and a number of potential oilfield locations were being considered as host sites for the demonstration test. Since site-specific characterization activities for a Williston Basin project could not be conducted without a formal agreement between the oilfield operator and the CO_2 provider, the PCOR Partnership elected to move forward with geological, geochemical, and geomechanical characterization and modeling activities using samples and data that would be applicable to several of the Phase III candidate oil fields within this region (Sorensen and others, 2008). However, negotiations between the oilfield operating company and commercial CO_2 provider in the Williston Basin were unsuccessful, and the PCOR Partnership had to identify another oilfield-based CO_2 injection project in the region that would meet the goals and objectives of the PCOR Partnership and the U.S. Department of Energy (DOE). The Bell Creek oil field in the southeastern Montana portion of the Powder River Basin was identified and became the host site for the Phase III demonstration project.

The Bell Creek field demonstration test evaluated the potential for associated geological storage of CO_2 during the deployment of CO_2 enhanced oil recovery (CO_2 EOR) in the oil field. CO_2 was initially obtained from the ConocoPhillips' Lost Cabin natural gas-processing plant in central Wyoming, which was later supplemented with, and eventually replaced by, CO_2 from the Shute Creek natural gas-processing plant of ExxonMobil, which is located in Green River, Wyoming (Figure 4-4). CO_2 is delivered to the EOR site at an injection-ready pressure of 2200 psi and is injected through multiple wells into a sandstone reservoir in the Lower Cretaceous-age Muddy Formation at a depth of approximately 4500 ft (1372 m) (Figure 4-5). A supply of approximately 50 million cubic feet of CO_2 per day is delivered to the site. The EOR activities at Bell Creek will store an estimated 1.1 Mt of CO_2 annually.

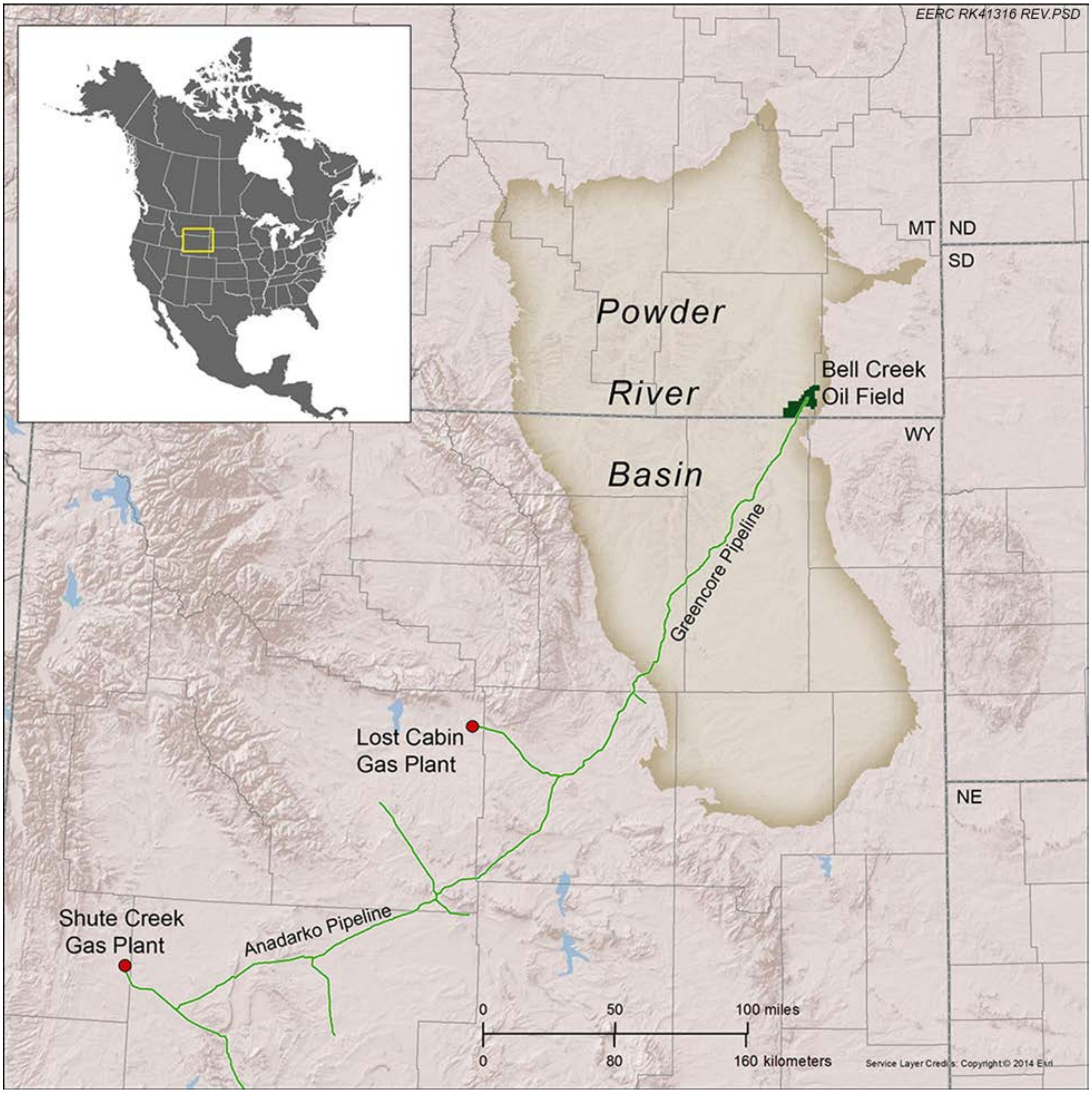

Figure 4-4. Map depicting the location of the Bell Creek oil field within the Powder River Basin and the pipeline routes to the site from the Lost Cabin and Shute Creek natural gas-processing plants.

Detailed subsurface mapping and site characterization activities were conducted at this site with the goal of developing predictive models that addressed the critical issues regarding the ultimate effectiveness of the targeted storage formation, discussed further in the modeling section below. A brief summary of activities performed at the Bell Creek oil field follows, with a summary of findings presented at the end.

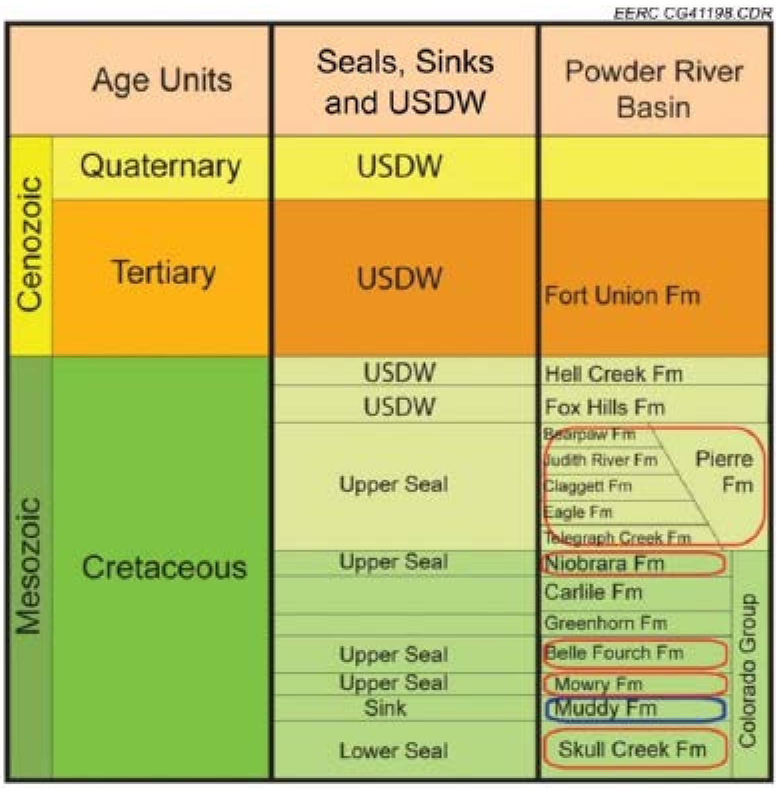

Figure 4-5. Late Cretaceous to Quaternary stratigraphic column of the Powder River Basin. Sealing formations are circled in red, and the injection formation for the Bell Creek demonstration test is circled in blue. Formations bearing USDWs are also identified.

Site Characterization

Site characterization activities at Bell Creek focused on investigation of key site parameters, including properties of the reservoir and seal rocks, properties of the fluids in the reservoir and overlying fluid-bearing formations, and production and operational history of the target oil reservoir. Specific efforts included baseline characterization of surface conditions and the reservoir, an investigation of mineralogy and formation water chemistry, identification of hydrogeologic characteristics, determination of geomechanical properties and stress regimes, and a wellbore integrity assessment (Sorensen and others, 2011; Laumb and others, 2014). Historic data sets were also assembled and, along with new data sets (e.g., core samples, well logs, and different types of geophysical surveys), were evaluated and interpreted. Results of these efforts were previously reported (Kalenze and others, 2013) and provided valuable input into a best practices manual for site characterization (Glazewski and others, 2017). The more salient of these efforts are summarized herein.

Baseline Hydrogeology. Baseline Bell Creek hydrogeologic characteristics were evaluated, including aquifer and aquitard geometry and thickness, rock properties relevant to the flow of formation waters and injected CO_2 (i.e., porosity and absolute and relative permeability), geothermal and pressure regimes, and the direction and strength of formation water flow (Botnen and others, 2011).

Geochemistry. The potential for geochemical changes in the subsurface during and after CO_2 injection was evaluated by conducting laboratory tests on samples of the target injection formation and key sealing formations under reservoir conditions. The purpose of these tests was to assess the potential for geochemical reactions to occur between the injected gas and the rocks and fluids of the reservoir and seal. Mineral compositions were obtained using XRD, XRF, and SEM techniques. Fluids from key formations were analyzed for major and minor constituents. Laboratory results were used to refine geochemical models developed for the site. Results of these preinjection geochemical evaluations were previously reported (Kurz and others, 2013) and included the following: 1) rock sample analyses within the CO_2 injection zone (Muddy Formation), as well as the sealing formations (Niobrara and Mowry Formations), to determine petrographic and petrophysical characteristics; 2) reservoir fluid analyses to characterize formation water chemistry and better understand the composition of hydrocarbons in the reservoir; 3) surface water, groundwater, and shallow vadose zone soil gas analyses to establish baseline characteristics of surface and shallow subsurface environments; and 4) results from laboratory-based CO_2 exposure tests of rock and water samples from the lowest groundwater zone (Fox Hills Formation) overlying the Bell Creek reservoir to better understand the possible effects of out-of-zone CO_2 migration to the shallow subsurface. In addition to these test results, a literature review of potential geochemical effects of CO_2 injection within the Bell Creek reservoir, and, in the unlikely event of out-of-zone migration, of CO_2 on the cap rock and within overlying groundwater zones was performed.

Geomechanical Properties. Geomechanical properties of the reservoir and cap rock were tested in laboratory investigations using core samples, and the stress regime of the area surrounding the Bell Creek site were examined using well log data to assess the mechanical integrity of the system and the potential for rock fracturing during CO_2 injection. An in-depth review of available information regarding the stress regime and structural geologic features in the area of the reservoir permitted identification of subsurface geologic structures, which helped elucidate the geologic history of the reservoir and enabled identification of possible natural leakage paths. Based on these efforts, a geomechanical experimental design package was developed and reported by Sorensen and others (2010). The results of the experimental geomechanical evaluations were presented in a preinjection geomechanical report by Ge and others (2013).

Wellbore Integrity. An assessment of wellbore integrity and leakage potential at the Bell Creek site was conducted. Well geometry and performance data within the selected oil field and surrounding regions were compiled. Wellbore integrity issues under conditions of CO_2 injection and long-term buoyancy-driven forces were evaluated. Both field data and analytical/numerical simulations were combined to quantify processes associated with the hydraulic integrity of the wells. Results of this assessment were presented in a wellbore leakage final report (Laumb and others, 2014).

Model Construction and Numerical Simulation

The PCOR Partnership initiated a modeling and numerical simulation effort as part of the Bell Creek demonstration test, with the goal of addressing three critical issues regarding the ultimate effectiveness of the targeted storage formation: 1) what is storage capacity of the target formation, in this case, an oil reservoir within an established oil field; 2) what are the movement and fate of CO_2 in the subsurface over near-, intermediate-, and long-term time frames; and 3) is there potential for leakage of injected CO_2 into overlying formations and/or the surface environment. Modeling and simulation efforts included:

- Development of a robust pressure, volume, and temperature model to predict the CO_2-oil miscibility behavior of the system and to aid in compositional simulation;

- Construction of dynamic reservoir models for history-matching of oil production from the reservoir; and

- Running predictive simulations to aid in monitoring the long-term behavior of the injected CO_2.

A suite of geologic models was created and comprised 1) Bell Creek reference model to enable consistency across various geologic modeling efforts; 2) static and dynamic geocellular models, which included incorporation of data from 33 baseline and 19 repeat pulsed-neutron logs (PNLs), 3) a clipped version of the history-matched Version 2 (V2) geologic model; and 4) a Version 3 (V3) geologic model, developed to incorporate 3-D surface seismic data and portray a new understanding of the reservoir's depositional history. Comments that warrant stating regarding each of models are as follows:

- Reference model: The reference model was constructed to house key data sets associated with the Bell Creek Field, including data from 751 wells, such as field and processed logs, core analyses, structural tops, cultural surface boundaries, completed simulation results, ground surface elevations from light detection and ranging (LiDAR), and 3-D surface seismic data. The reference model provides a foundation that ensures consistency across all past and future modeling efforts at the site.

- History-matched V2 geologic model: Individual Phase 1 and 2 simulation models, previously developed and reported (Liu and others, 2014) were combined to form a new simulation model that enables simulated fluid flow between the various phases of EOR field development. Improvements to the V2 geologic model resulted from 1) history-matching 47 years of field records with primary production, waterflooding, and CO_2 EOR in Phase Areas 1 and 2; 2) analyzing fluid saturation distribution in the reservoir using information from pulse neutron logs (PNLs); and 3) identifying cross-boundary fluid flow between Phase Areas 1 and 2.

- V3 geologic model: Previously developed V1 and V2 geologic models were rooted in the conventional Bell Creek depositional interpretation of stacked barrier bar sands within a large, Galveston Island-style depositional environment, oriented approximately northeast to southwest. Further information provided by history-matching during simulation efforts, incorporation and interpretation of 3-D and 4-D seismic surveys, and comparison of PNL measured oil saturations with modeled oil saturations led to the development of a new understanding of the Muddy Formation depositional history and the creation of a new geologic model, V3, which incorporated new geophysical data, results from the history-matched simulation model, and the new geologic interpretation. This model was used along with the V2 model in the history-matching and predictive simulation efforts to better understand the long-term fate of injected CO_2.

Summary of Findings

An overview of the more signficant findings of characterization and modeling efforts at the Bell Creek site is provided below:

- Seismic survey data are critically important to accurately assess the viability of a candidate storage complex; however, seismic data acquisition is a major undertaking in terms of logistics, cost, and time. If affordable, hiring a qualified expert to act as a general contractor to assemble the required participants and coordinate the overall work effort is the most convenient, efficient, and effective way to execute a seismic survey.

- Based on petrographic analysis, the Niobrara and Mowry shales exhibited very low (<1%) porosity and are expected to act as viable seals, preventing vertical migration of CO_2 and formation fluids from the storage reservoir.

- Seasonal variations in surface and groundwater chemistry and in soil gas CO_2 concentrations from baseline monitoring efforts were detected, illustrating the need for long-term monitoring to adequately differentiate between natural variations in these parameters versus possible effects of the unlikely migration of injected CO_2 out of the storage complex.

- Results of Bell Creek CO_2 exposure testing were consistent with existing literature and suggested that monitoring of compositional changes in groundwater chemistry offered an opportunity for detecting potential out-of-zone CO_2 migration into the groundwater zone overlying the Bell Creek reservoir.

- Based on existing literature and mineralogical content of the Bell Creek reservoir, geochemical changes to rock and formation fluids were expected but with minor implications for CO_2 storage.

- Stress polygon computations indicated that the potential of borehole breakout through the reservoir as a result of drilling was extremely low.

- Overall, wellbore integrity assessment indicated sound wellbore integrity throughout the study area, despite the Bell Creek Field being an actively producing oil field. This screening-level ranking of relative integrity factors of individual wells provided a means to identify those wells that require further detailed evaluation, which is critical information for strategically guiding wellbore-monitoring activities within the field.

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APPENDIX 5

TASK 5 – WELL DRILLING AND MONITORING

TASK 5 – WELL DRILLING AND COMPLETION

INTRODUCTION

The CO_2 injection and oil production program at the Bell Creek oil field is dictated by the needs of the commercial enhanced oil recovery (EOR) project. Between December 2011 and April 2013, the Plains CO_2 Reduction (PCOR) Partnership at the Energy & Environmental Research Center (EERC) assisted Denbury Resources Inc. (Denbury) (the CO_2 EOR operator) at the Bell Creek oil field with the design and installation of additional wells for the purpose of 1) demonstrating that CO_2 injection is safe and viable at a commercial scale, 2) understanding associated storage of CO_2 that occurs during the EOR process, and 3) informing development of monitoring strategies that can be used for future CO_2 injection projects. To the extent possible, these efforts, which targeted characterization of site geology and monitoring of seismicity and deep subsurface groundwater, leveraged available operational data and the use of existing injection and production wells that were already in place, or planned for, as part of the commercial EOR operations (Kalenze and others, 2013a,b). This task included collection of a subset of baseline monitoring data for the demonstration test; more details on baseline and operational monitoring programs, including specific monitoring techniques, are provided in the Task 9 summary (Appendix 9).

COMMERCIAL INJECTION SCHEME

The CO_2 injection program at the Bell Creek oil field is being implemented in a staged approach, moving sequentially across nine phases of the field (Figure 5-1). Injection and production occur in a typical five-spot pattern of 40-acre spacing, as demonstrated for Phase Areas 1 and 2 of the project (Figure 5-2). Typical of standard EOR operating procedures, CO_2 and water are separated from the produced oil at on-site process/recycle facilities and are recycled for reinjection as part of the water alternating gas (WAG) operation.

MONITORING SCHEME DESIGN AND DRILLING ACTIVITIES

The goal of the monitoring program was to document the associated storage of CO_2 that occurs during CO_2 EOR operations. To achieve this goal, it was necessary to verify storage site security, evaluate reservoir behavior during CO_2 injection, determine the interactions and fate of CO_2 within the reservoir, and identify the mechanisms that affect CO_2 storage efficiency within the reservoir. The design of the monitoring program was guided by subsurface technical risks of concern and predicted results from reservoir simulations. While the resulting program was specific to the needs of the Bell Creek demonstration test, lessons learned from its implementation could be applied at other commercial CO_2 storage sites.

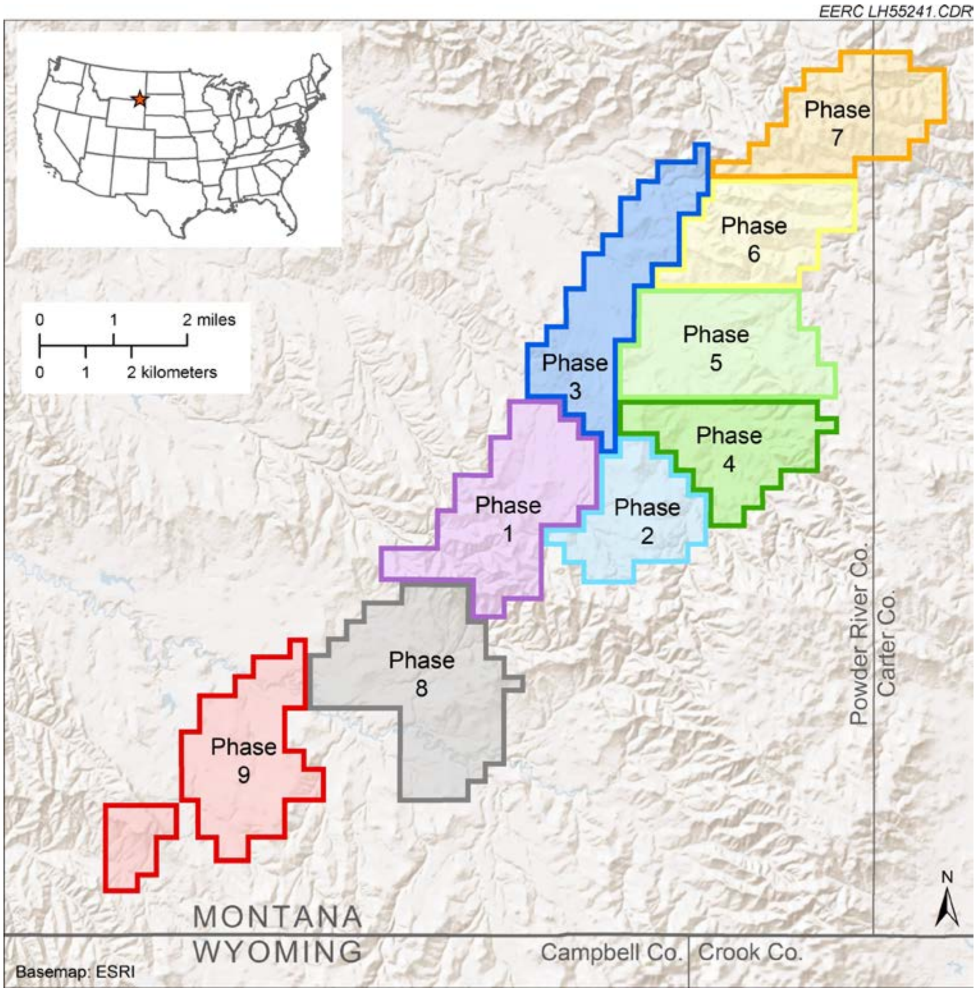

Figure 5-1. Phased development of the Bell Creek demonstration project consists of nine distinct phases.

Following an evaluation of the field, six wells, as shown in Figure 5-3, were drilled in Phase Areas 1 and 2 of the site to address the following needs:

- Well 05-06 OW (observation wells; drilled December 2011): characterization and deep subsurface monitoring.

- Well 04-03 OW (drilled April 2013): installation of geophone array and monitoring.

- Wells 56-14R (drilled February, 2013) and 33-14R (drilled March 2013): characterization (redrilled wells by Denbury for infilling).

- Wells MW0504 and MW3312 (drilled January and February 2013): characterization and monitoring of groundwater in the Fox Hills Formation, which is the deepest underground source of drinking water (USDW) at the site.

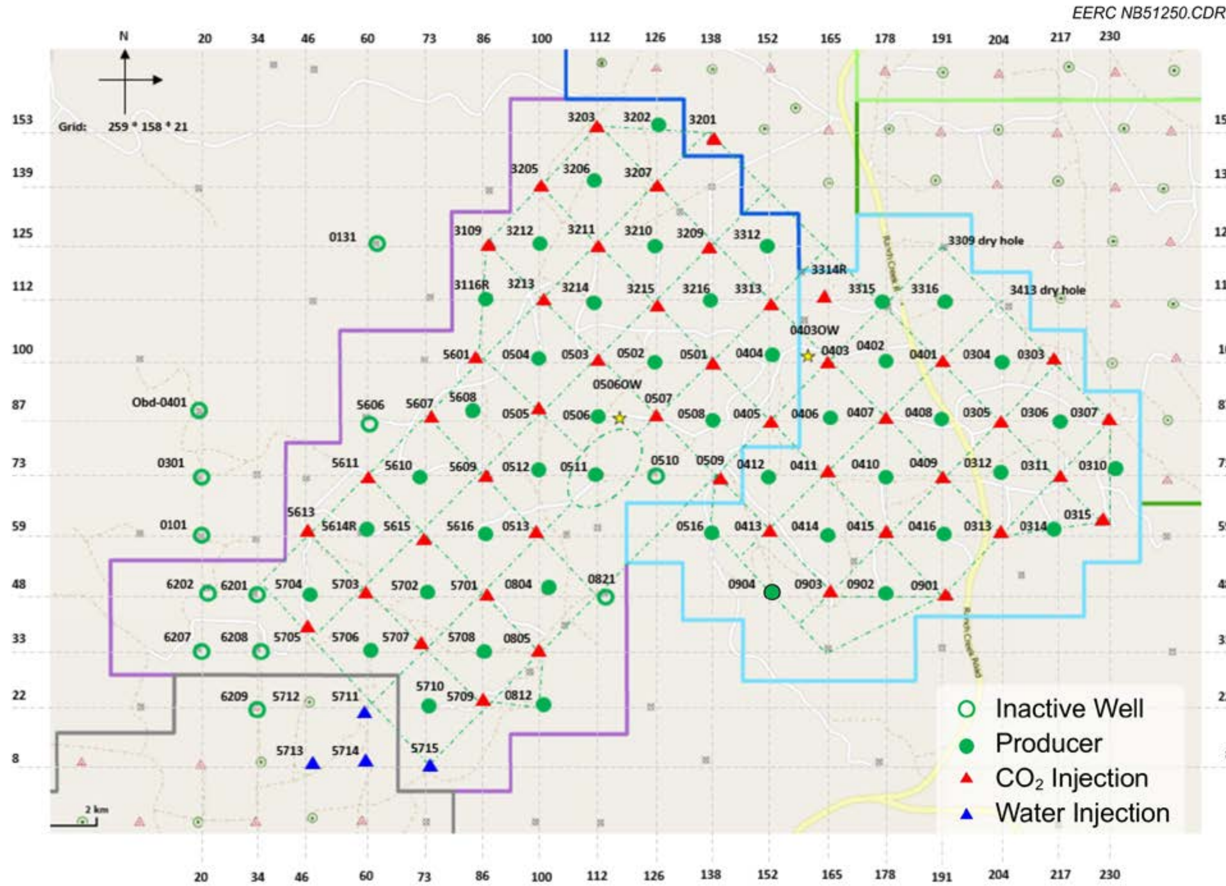

Figure 5-2. Example of the 40-acre five-spot injection/production pattern being implemented at the Bell Creek demonstration test. Injection and producer wells are depicted for Phase Areas 1 (outlined in purple) and 2 (outlined in blue) of the site.

During drilling of these wells, core and well logs were collected and instrumentation was installed. A description of installed instrumentation and data collection efforts has been previously reported (Heebink and others, 2014) and is briefly summarized below.

Well 05-06 OW

A permanent downhole monitoring (PDM) system was installed in this well in April 2012. The PDM system consists of three permanent downhole pressure and temperature gauges and a distributed fiber optic measurement system. The output of these sensors provides continuous in situ measurements of reservoir pressure and temperature during the CO_2 flood, which are used as early indicators of potential CO_2 leakage outside of the reservoir. Numerous open- and cased-hole logs were obtained in this well along with other data sets such as retrievable 3-D vertical seismic profiles (VSPs) and pulsed-neutron log (PNL) surveys.

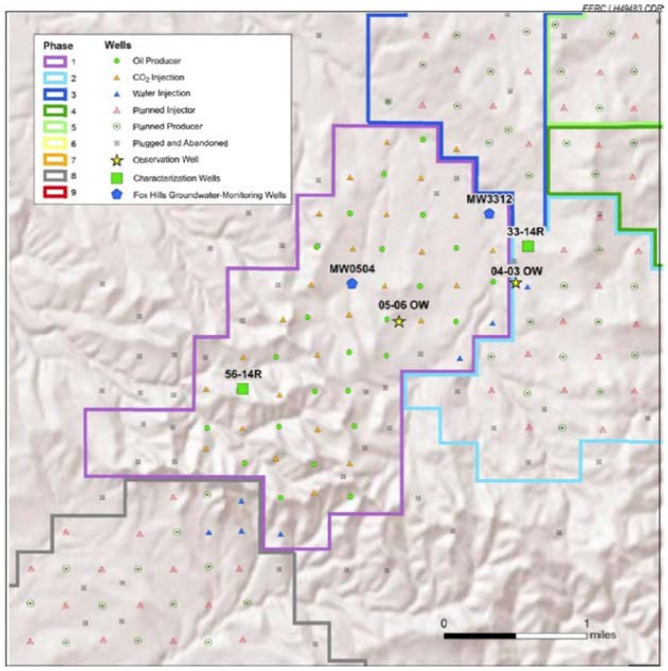

Figure 5-3. Location of monitoring wells drilled within Phase Areas 1 and 2 of the Bell Creek oil field to support PCOR Partnership efforts.

Well 04-03 OW

This well was drilled to install a permanent 50-level, three-component geophone array to allow for time-lapse VSP acquisitions and to provide continuous passive seismic monitoring of the injection and adjacent formations. Other limited characterization data, such as resistivity, gamma ray, spontaneous potential, and multi-arm caliper logs, were also acquired from this well to aid in seismic processing and to comply with state requirements. The geophone array began collecting data in the vicinity of the Bell Creek oil field as of mid-May 2013.

Wells 56-14R and 33-14R

These wells were drilled as part of the infilling activities of Denbury. However, they provided a very unique opportunity to collect and analyze rock samples that filled in critical characterization data gaps: 1) Well 56-14R provided rock samples from the upper sand interval of the reservoir and contact between the reservoir and the cap rock (56-14R), which could not be collected in Well 05-06 OW, and 2) Well 33-14R provided the opportunity to collect some of the incised valley fill shale that divides several of the phase areas of the field, including separation of Phase Area 1 from Phase Area 2. Several logs (i.e., resistivity, gamma ray, neutron porosity, bulk density, spontaneous potential [anisotropy, P and S wave, and mechanical rock properties], borehole volume, magnetic resonance) were also obtained from Well 33-14R.

Wells MW0504 and MW3312

The primary goal of the Fox Hills groundwater-monitoring effort was to provide a means to identify and characterize baseline water chemistry in the lowermost USDW, as well as identify water chemistry anomalies (should they occur) associated with CO_2 content, whether it be a natural or other source. The baseline groundwater chemistry and periodic monitoring data that are collected during the injection period, in conjunction with the greater monitoring program, can be utilized to identify an anomaly, determine the source of the anomaly, and confirm or contest the impact of an anomaly on local groundwater aquifers (should an impact be observed).

In summary, each of the drilled wells provided key characterization and operational monitoring data for the Bell Creek demonstration test. Advanced wireline log suites aided in the creation of geologic models that were used in the simulation of the reservoir. Core samples provided additional porosity, permeability, and mineralogy data, and provided confirmation of lithofacies within the reservoir. Continuously collected pressure and temperature data aided in monitoring CO_2 injection and confirming its containment within the reservoir. Produced gas sampling and analysis further assisted monitoring of CO_2 flooding efficiency and storage performance, while groundwater-monitoring wells provided physical, time-sensitive confirmation that CO_2 was not migrating into overlying drinking water sources in the Fox Hills Formation.

BASELINE MONITORING, VERIFICATION, AND ACCOUNTING (MVA) ACTIVITIES

Drilling and completion activities conducted by the PCOR Partnership in conjunction with the Bell Creek demonstration test have provided several key baseline data sets integral to MVA activities. Additionally, the 05-06 OW, 04-03 OW, MW0504 (Fox Hills), and MW3312 (Fox Hills) wells have provided crucial access to conduct operational monitoring activities to 1) demonstrate that associated CO_2 storage can be safely and permanently achieved and monitored on a commercial scale in conjunction with an EOR operation; 2) demonstrate that oil-bearing sandstone formations are viable CO_2 sinks; 3) develop and demonstrate MVA methods that can be used to effectively monitor commercial-scale CO_2 injection projects and provide a technical framework for the accounting of injected CO_2; and 4) acquire data, information, and knowledge needed to inform commercial-scale CO_2 storage and EOR projects throughout the region.

In addition to these contributions to MVA activities, the technical team of the EERC, Denbury, and other project partners conducted a variety of activities to determine baseline reservoir characteristics, including an evaluation of reservoir depositional environment, injectivity, and storage potential. These activities, which included evaluations of available well logs, production/injection records, and predictive reservoir simulations, confirmed that the Muddy sandstone in the Bell Creek Field has adequate characteristics to accept CO_2 injection for EOR operations and associated storage.

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APPENDIX 6

TASK 6 – INFRASTRUCTURE DEVELOPMENT

TASK 6 – INFRASTRUCTURE DEVELOPMENT

INTRODUCTION

The purpose of Task 6 of the Plains CO_2 Reduction (PCOR) Partnership Program at the Energy & Environmental Research Center (EERC) was to facilitate infrastructure planning associated with the capture, dehydration, compression, and pipeline transportation of CO_2 from its source to an end user. This effort supported geological storage studies and included investigation of 1) technologies for capturing CO_2 from various industrial or utility processes; 2) CO_2 compression needs and various types of compressors that are available to meet them; and 3) existing and potential pipeline routes to move CO_2 from potential sources to potential sinks within the PCOR Partnership region. With this information in hand, an attempt was made to match specific CO_2 sources with specific CO_2 sinks and to identify preliminary pipeline networks to move CO_2 from the former to the latter for consideration during future planning by interested stakeholders.

CO_2 CAPTURE TECHNOLOGIES

The EERC completed a review of the status of carbon capture technology development and applications (Cowan and others, 2011). This overview covered technologies that apply to the three combustion platforms: precombustion, during combustion (oxycombustion and chemical-looping combustion), and postcombustion. As shown in Figure 6-1, capture technologies fall into the categories of physical and chemical absorption; physical and chemical adsorption; oxygen-, hydrogen-, and CO_2-permeable membrane processes; cryogenic processes; mineralization; and photosynthesis, chemical, and biochemical reduction processes. The overview presented the technical basis for each separation technique and provided the most current information available on nearly 100 technologies and/or research efforts. The report also featured an extensive 27-page list of references; an index to allow the reader to quickly find specific technologies or developers; and a summary table organized by combustion platform that listed the name, developer(s)/supplier(s), type, development status, and chemicals used during the process for each of the technologies discussed in the report.

The initial carbon capture review was updated in 2018 and summarized in a companion report (Jensen and Gorecki, 2018). The update discussed new trends in CO_2 capture, including new developments in capture at industrial facilities and electric utilities, direct capture of CO_2 from the air, and carbon capture and storage combined with bioenergy production. Large-scale and commercial demonstrations of CO_2 capture and storage or beneficial use around the world were also summarized in the report, and selected new and novel developmental capture technologies were highlighted. It should be noted that Figure 6.1 features only the capture technologies that were included in the 2011 report and does not include any of the technologies that were discussed in the 2018 report.

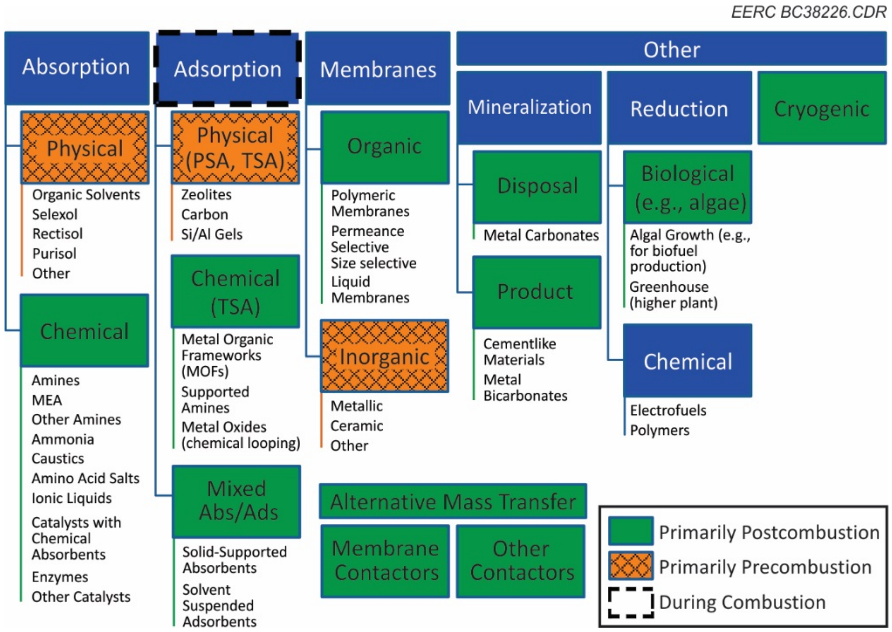

Figure 6-1. Categories of CO_2 capture technologies reviewed by Cowan and others in 2011. The figure does not include technologies that were discussed in Jensen and Gorecki (2018).

CO_2 COMPRESSION AND TRANSPORT

EERC investigations of CO_2 compression and transport were summarized in four reports, which included "Opportunities and Challenges Associated with CO_2 Compression and Transportation during CCS Activities" (Jensen and others, 2011), its two updates (Jensen and others, 2015, 2017) and "Preliminary Design of Advanced Compression Technology" (Jensen and others, 2009a). These reports, which addressed different facets of compressing captured CO_2 for transport, are briefly discussed below.

Opportunities and Challenges Associated with CO_2 Compression/Transportation

Initial review of the compression and transport of CO_2 associated with carbon capture, utilization, and storage (CCUS) activities identified several opportunities for improved compression and transport efficiency and cost, which include the following:

- More precise compressor design is possible based on a more thorough understanding of the behavior of mixed CO_2 streams near the critical point of CO_2.
- Better integration of CO_2 capture and compression provides more opportunities for improved efficiency, especially with respect to the use of heat generated during interstage cooling during compression.
- Improved compression efficiency may be possible through the use of compression pathways that also include liquefaction and pumping of the CO_2.

- Efficiency gains are possible using advanced compressor design, such as the shockwave technology under development by Ramgen.

- Compressor electric drives and associated components that can operate at higher power rankings more reliably and efficiently should be developed.

- A large-scale CO_2 pipeline network should be developed, and common carrier CO_2 stream composition requirements should be established.

The updates of this initial effort focused on 1) selection of compression technology based on its potential impact on overall CO_2 capture plant efficiency and 2) investigation of developing a universal CO_2 pipeline specification that could be applied to the majority of capture projects. With regard to plant efficiency, it was determined that the best CO_2 capture plant efficiency and economics are achieved by integrating the capture technology, dehydration step, and compression approach, and integrating the compressor waste heat into the overall capture plant. In addition, it was determined that liquefying CO_2 rather than compressing it to a supercritical phase has not been proven to be more efficient or cost-effective than traditional gas compression techniques (Jensen and others, 2015).

As for a universal CO_2 pipeline specification, research indicated that gas streams captured from various industries or utilities are remarkably similar in composition and generally can meet pipeline specifications required by enhanced oil recovery (EOR) operations. Depending on the end use, additional purification may be needed for CO_2 to meet purity requirements of the end user. CO_2 stream composition specifications have been developed by Kinder Morgan to ensure safe transport and structural integrity of a pipeline carrying CO_2. These specifications have been adopted by many companies that transport CO_2 by pipeline. Approaches taken to address issues created by the presence of impurities in the CO_2 stream are to upgrade pipe metal or increase its thickness, adopt lined pipe, or switch to organic polymer composite pipe. Although a universal CO_2 specification could not be identified, the concepts investigated offer a different approach for development of a more cost-effective, integrated CCUS system, especially if a large-scale pipeline network is considered.

Advanced Compression Technology

A novel approach utilizing supersonic shock compression was investigated by the EERC (Jensen and others, 2009a). This type of compression stage was called the Rampressor™ and was under development by Ramgen Power Systems.[1] Supersonic compression is very efficient and quite cost-effective, offering a step change in both areas over traditional compression. Research performed by the EERC investigated integration of the Rampressor into large-scale CCUS demonstration tests of the PCOR Partnership Program. Unfortunately, it was determined that the status of the compressor was not sufficiently advanced to permit its incorporation into the large-scale demonstration test being conducted at the Bell Creek oil field in Montana.

[1] The technology has since been purchased by Dresser-Rand and is now part of its DATUM-S series of compressors.

CO_2 PIPELINE ROUTES AND NETWORKS

The EERC matched large regional point sources of CO_2 and geologic sinks in the PCOR Partnership region and devised preliminary pipeline network routes to move CO_2 between them. The development of these hypothetical pipeline networks was previously reported and is briefly described here (Jensen and others, 2009b, 2013a, b).

Preliminary economic assessment of a pipeline network focused on three CO_2 source types that are well represented in the PCOR Partnership region: natural gas-processing plants, ethanol-producing facilities, and coal-fired power plants. A pipeline network was developed by adding the annual mass of CO_2 from one source to the next closest source. This process was repeated to form feeder lines and minor and major trunk lines for each of the states and provinces in the PCOR Partnership region. Pipelines were routed toward geologic sinks and connected at the borders of states and provinces. The resulting hypothetical network is presented in Figure 6-2. Capital and construction costs of this hypothetical 9900-mile pipeline network were estimated to be \$11.5 billion; operations and maintenance costs were estimated to be about \$50 million annually.

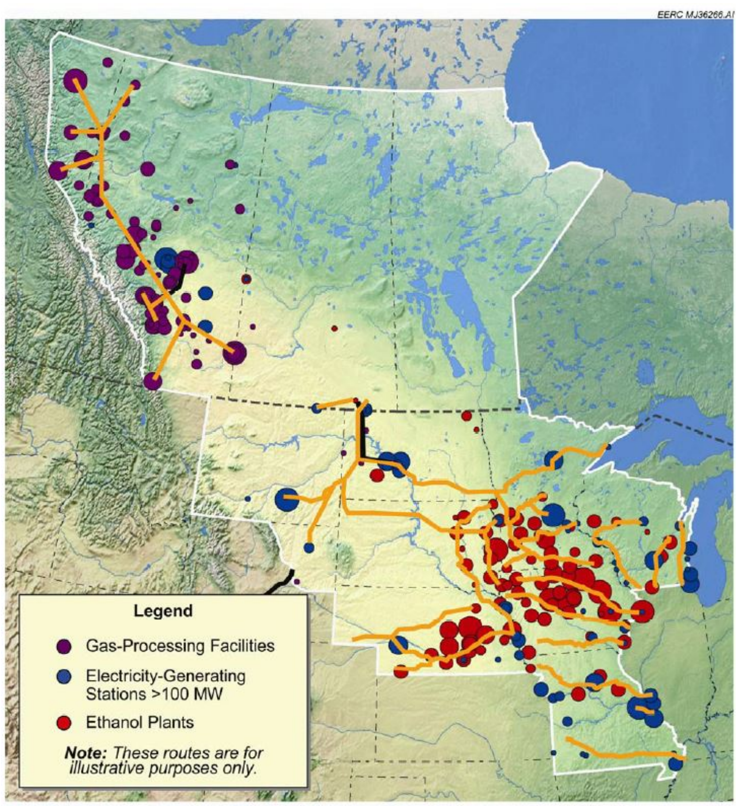

Figure 6-2. Hypothetical CO_2 pipeline network devised for the PCOR Partnership region connecting natural gas-processing, ethanol-producing, and electricity-generating facilities with secure geologic storage sites. Gold lines are hypothetical pipelines; black are existing or planned pipelines.

Since many large CO_2 sources are not located near appropriate geologic storage areas, it is likely that one or several regional pipeline networks will be needed to transport the CO_2 from sources to storage sinks. Such networks would probably be built in stages or phases. The EERC performed a study to estimate how CO_2 pipeline networks might be built out in the PCOR Partnership region, considering both the time frame and cost of the effort. Study results indicated that a pipeline network comprised of roughly 6700 miles of trunk lines could transport sufficient quantities of CO_2 to meet the International Energy Agency (IEA) BLUE Map scenario in the PCOR Partnership region by 2050. The IEA BLUE Map scenario represents a 50% reduction in CO_2 emissions over 2005 levels by 2050 (International Energy Agency, 2010), which would be an overall reduction of approximately 612 MM tons per year for the PCOR Partnership (Jensen and others, 2012a). Because of the interest in this research, in addition to previously referenced published manuscripts, project results were also reported at technical conferences of the CCUS industry (Jensen and others, 2012b, c).

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APPENDIX 7

TASK 7 – CO_2 PROCUREMENT

TASK 7 – CO_2 PROCUREMENT

INTRODUCTION

The objective of Task 7 was to document procedures for procuring CO_2 as part of a carbon capture, utilization, and storage (CCUS) strategy in the Plains CO_2 Reduction (PCOR) Partnership region. The goal of this task was to identify critical technical and cost factors, as well as other considerations, and their potential impact on procurement of CO_2 for future CCUS projects in the region and beyond.

One of the primary strategies of interest for the deployment of CCUS in the PCOR Partnership region involves the use of captured CO_2 for enhanced oil recovery (EOR).[1] However, limiting factors for these projects, as well as all other CCUS projects, are access to a CO_2 supply source and the distance from the source to the end user, or sink. Although the PCOR Partnership region has tremendous dedicated and associated CO_2 storage potential and is home to hundreds of large-scale sources of CO_2, the vagaries of commercial oil and gas business operations, coupled with the high cost of CO_2 capture and transportation, made it difficult to locate an acceptable CO_2 EOR site for a Phase III demonstration test. More specifically, two options for a proposed demonstration test in the Williston Basin proved unsuccessful because of 1) failed negotiations between the owner of the CO_2 and the operator of the oil reservoir and 2) lack of timeliness associated with selection of a CO_2 capture technology at the source, which was the direct result of the high cost of capture coupled with the uncertainty associated with evolving federal environmental legislation and regulations. However, a demonstration test was successfully structured in 2009 with Encore Acquisition Company (Encore), a PCOR Partnership partner.[2] As part of this project, Encore agreed to acquire CO_2 for EOR from a natural gas-processing facility, while the Energy & Environmental Research Center (EERC) was responsible for designing and conducting CO_2 monitoring, verification, and accounting (MVA) activities. The selected project site was the Bell Creek oil field in Powder River County, southeastern Montana, where oil would be produced using a tertiary miscible CO_2 flood (hereafter, the "Bell Creek Project"). The purpose of EERC MVA activities of the Bell Creek Project was to document associated storage of CO_2 within a sandstone reservoir in the Powder River Basin Cretaceous Muddy Formation.

Task 7 was accomplished based on the experience at the CO_2 EOR Bell Creek project, where CO_2 is provided by ConocoPhillips from its Lost Cabin gas plant to Denbury, the operator of the Bell Creek oil field, and is documented below.

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[1] Storage of CO_2 during EOR operations has been designated as "associated storage," in contrast to storage in a saline aquifer, which is called "dedicated storage." In the latter case, mitigation of greenhouse gas (GHG) emissions is the primary purpose of the underground injection of CO_2. In the former case, GHG mitigation is a secondary outcome of CO_2 injection operations.

[2] Negotiations were under way to formalize an agreement with Encore when Denbury Resources Inc. (Denbury) announced the signing of a definitive merger agreement with Encore on November 1, 2009, which would leave Denbury as the surviving entity (Oil and Gas Journal, 2009). The merger was finalized on March 9, 2010 (Denbury Resources Inc., 2010).

CO_2 PURCHASE AND SALE AGREEMENTS

The Bell Creek Project included execution of a 15-year CO_2 purchase-and-sale agreement that included procurement of a CO_2 supply from the Lost Cabin Gas Plant of ConocoPhillips, which is located in Fremont County, Wyoming. (Denbury, through premerger entity, Encore, and ConocoPhillips entered into this agreement in July 2009 [Sorensen and others, 2009]). Transport of CO_2 from the Lost Cabin Gas Plant to Bell Creek was accomplished via the Denbury-owned Greencore pipeline, a 232-mile-long, 20-inch pipeline, which was completed in late November 2012. CO_2 injection at the Bell Creek oil field began in May 2013.

Many of the details regarding procurement of CO_2 for the Bell Creek Project are considered proprietary by the buyer and site operator, Denbury. Under terms of the agreement, Denbury would purchase all of the CO_2 available from the Lost Cabin Gas Plant. Initially, the volume of CO_2 was estimated to be approximately 50 MMcf/d (1.4 million m^3/d). As previously noted, the initial term of the contract was 15 years, or through 2024. In addition to constructing the CO_2 pipeline, Denbury also built compression facilities adjacent to the gas plant and upgraded its secondary waterflood recovery project into a tertiary miscible CO_2 flood (Encore Acquisition Company, 2009). While it is not publicly known how the price of CO_2 is calculated in the CO_2 agreement, Denbury's existing Lost Cabin contract includes price adjustments that fluctuate based on the price of oil (Denbury Resources Inc., 2011).

General Terms

CO_2 purchase and sale agreements are entered into between the seller (i.e., holder of legal rights to a CO_2 supply) and a buyer, which in this case is the operator of an oil field. These agreements, which contain detailed seller and buyer information, details regarding the type of sale, and numerous contractual dates (e.g., date of initial agreement, dates when other parts of the contract are to be completed, date of final closing of the contract and transfer of ownership, etc.), are considered "living" documents because they are very often subject to revisions. Sale agreements are designed to provide each party with a degree of flexibility before entering into a contract and are often put in place for major acquisitions to ensure that one party does not compromise the agreement when completing the sale.

There is no such thing as a "standard contract" for these purposes. Furthermore, many contract terms, in addition to pricing, can differ significantly depending on where the change of CO_2 ownership occurs, e.g., precompression (at the source, prior to compression), postcompression (at the source but after compression and before entering the pipeline), or at the EOR site (at the end of the pipeline but prior to injection) (Keith Tracy, 2012).

Standard CO_2 Sales Terms

Some of the more important sales terms that are provided in a standard CO_2 sales agreement, and their definition as part of the Bell Creek Project agreement, are provided as follows:

- *Who*: Buyer and seller – At Bell Creek, the buyer is Denbury and the seller is ConocoPhillips.

- *Where*: Defined delivery point or change of ownership.

- *When*: Term, including any renewal periods. In the ConocoPhillips–Denbury agreement, the term is 15 years.

- *What*: Quality (purity and composition of the purchased CO_2 stream). Certain CO_2 stream impurities are a concern for the end user. For example, in an EOR field, a number of impurities in the CO_2 can affect minimum miscibility pressure of EOR operations and negatively affect incremental recovery of oil. These include nitrogen, methane, and hydrogen sulfide. Oxygen and water can also have a negative effect on the integrity of the transportation pipeline.

- *How much*:

  1. Quantity of CO_2. This is often measured in MMcf/d, and may be designated as "daily contract quantity." It can be a fixed volume or fluctuate over time, e.g., based on EOR production response which often starts slow, increases, and then declines. At Bell Creek, the initial quantity is specified as 50 MMcf/d.

  2. Pressure. This is usually stated as a minimum pressure, in psig (pounds per square inch gauge), of the CO_2 stream at the delivery point, and can dramatically affect price, e.g., cost of compression from atmospheric pressure to pipeline pressure.

  3. Price. This can be fixed or formula-driven based on oil prices or other factors. It is most often expressed in dollars/MMcf. The price may have periodic escalators (e.g., annually), and portions of the price may incorporate actual operating costs (e.g., electricity for compression costs). As stated above, Denbury's existing Lost Cabin contract has price adjustments that fluctuate based on the price of oil. Typical oil prices that can be used for this purpose include the following:

     - WTI = Then-current oil price, based on WTI (West Texas Intermediate), NYMEX (New York Mercantile Exchange) or other posted prices for crude oil that are expected to change over time.

     - FOP = Fixed oil price (typically market price at time of contract execution) which is based on an initial crude oil reference price that does not change during the contract.

Pricing transactions historically tended to be fixed or included a modest variable component. In the late 1980s and early 1990s, prices trended very low, e.g., $0.55/MMcf, because the market had a significant excess supply. Today, prices tend to be highly variable mainly because of crude price fluctuations.

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APPENDIX 8

TASK 8 – TRANSPORTATION AND INJECTION OPERATIONS

TASK 8 – TRANSPORTATION AND INJECTION OPERATIONS

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership at the Energy & Environmental Research Center (EERC) collected information about the infrastructure that was needed to transport and inject CO_2 at the Bell Creek demonstration test site. This effort included an investigation of the construction and installation activities associated with the transportation pipeline as well as documentation of the surface facilities required to inject CO_2 into the storage reservoir. The results of these efforts were reported in two documents, Bell Creek Test Site – Infrastructure Development Report, D45 (Jensen and Gorecki, 2016) and Bell Creek Test Site – Transportation and Injection Operations Report, D49 (Jensen and others, 2015), and are summarized here.

TRANSPORTATION PIPELINE INFRASTRUCTURE

Prior to the initiation of the Phase III demonstration test at the Bell Creek site in Montana, the commercial partner, Denbury Onshore LLC (Denbury), constructed the Greencore pipeline for CO_2 enhanced oil recovery (EOR). The methods used by Denbury to construct and then operate this CO_2 pipeline may also apply to CO_2 transport during a carbon capture and storage (CCS) project, and provided the EERC with an opportunity to observe and monitor the basic steps involved with the planning and execution of these activities. In doing so, the EERC gained insight regarding the basic components of a commercial CO_2 pipeline, the steps involved in constructing and installing such a pipeline, and the monitoring of its operation (Jensen and Gorecki, 2015).

Pipeline Description and Basic System Components

CO_2 for the Bell Creek site is sourced from the ConocoPhillips Lost Cabin Gas Plant and the ExxonMobil Shute Creek natural gas-processing facilities. A target amount of at least 1.4 million m^3/d (50 MMcfd) CO_2 that was previously vented to the atmosphere is now compressed and transported via pipeline to Bell Creek. The quantity of CO_2 contributed to the Bell Creek site by the two plants has varied significantly since injection start in May 2013, averaging about 1.7 million m^3/d (60 MMcfd) over the last 5 years.

CO_2 is transported to the Bell Creek site via Denbury's Greencore pipeline, which is approximately 373 km (232 mi) long. The pipeline was designed to transport as much as 20.5 million m^3/d, or 38,150 t/d (725 MMcfd, or 42,053 short tons/d) CO_2, although plans called for the Greencore pipeline to initially transport a target rate of 1.4 million m^3/d, equal to 2630 t/d (50 MMcfd, or 2900 short tons/d) (Denbury Resources Inc., 2015). The pipeline right-of-way (ROW) passes through private (65%), federal (30%), and state (5%) land (Blincow, 2013). The pipeline is 20 inches. in diameter and was designed for a maximum operating pressure of 15.2 MPa (2200 psi). Pipeline construction comprised a standard sequence of steps, including such actions as surveys/staking, clearing, grading, trenching, field welding (including x-ray inspection and coating), hydrostatic testing, backfilling, and site restoration. Construction of the pipeline began in August 2011, and the flow of CO_2 began in December 2012. The pipeline costed an estimated US$285 million (Blincow, 2013; Hallerman, 2013).

The Greencore CO_2 pipeline project plan of development provided construction details for the Greencore pipeline. Briefly, the pipeline includes multiple tee (for future tie-ins) and block valves, as well as scraper receipt/launcher traps and pigging stations (to allow cleaning and visually checking the pipeline interior using pipeline pigs). Pump stations were also constructed at three locations along the pipeline route to accommodate the addition of future volumes of CO_2. These stations comprise valve manifolds, pumps, pigging equipment, power distribution, and control buildings (Jensen and others, 2015).

Construction and Installation

Approximately 19 steps are involved in constructing and installing a CO_2 pipeline. These steps are divided between three phases of standard construction and installation:

- Preconstruction – All biological and cultural impacts and permit stipulations are addressed prior to any construction activities. Engineering surveys are used to identify the pipeline centerline as well as the boundaries of the permanent ROW, which is 15.2 m (50 ft) wide. An additional temporary workspace, 15.2 m (50 ft) wide, is located parallel and adjacent to the ROW, and site-specific best management practices are used to limit erosion and transport of sediment in accordance with a stormwater pollution prevention plan.

- Construction – Construction activities prepare the pipeline route for the placement of the pipe. It includes a combination of methods such as clearing and grading, trenching, and blasting, if necessary; borings and/or open cuts for railroad and road crossings; horizontal directional drilling for water body crossings; and site-specific techniques for those areas of the route with special conditions, e.g., cultural resources, active faults, etc.

- Pipeline installation – Pipe installation includes stringing, bending of pipe for angles in the alignment, welding of the segments together, applying corrosion prevention coating, and placement of the pipe into the ditch.

After a section of pipe has been placed in the ditch, backfilling is conducted using subsoil previously excavated from the trench. Rocky areas may need imported fill material. The backfill is graded and compacted. In irrigated agricultural areas, the soil is compacted to the same density as the adjacent undisturbed soil, and a 0.2-m (0.5-ft) mound will generally be placed over the trench to allow for subsequent subsidence.

Pipeline Operation and Monitoring

An existing Denbury pipeline supervisory control and data acquisition (SCADA) control center is being used for the pipeline. SCADA is an industrial automation control system that provides control of remote equipment. Field SCADA equipment is located at the supply station at the CO_2 source, the mainline valve sites, and the meter stations at the Bell Creek site. Future pump stations will also have unit control centers that communicate their status to the Denbury SCADA control center. The main center will continuously monitor pipeline pressure and flow conditions at all supply and delivery points. It is programmed to alarm whenever a deviation in pressure or flow indicates an abnormal condition within the pipeline system. The pipeline is operated and maintained in accordance with industry standards and regulations.

Denbury's pipeline management plans include 24-hr monitoring of pipeline operations using the pipeline SCADA system, aerial and ground surveillance that is performed on a regular basis to look for signs of damage or encroachment, regular pressure testing of pipelines, an integrity management program, and installation of pipeline marker signs at varying intervals and on both sides of road crossings. Denbury also works with communities along the pipeline route to provide them with current information on emergency response procedures. The quarterly "Denbury Aware" newsletters provide interested parties with timely information regarding the pipeline transport of CO_2. The newsletters can be accessed from the Denbury Web site at the following Web address: www.denbury.com/responsiblity/public-awareness/Denbury-Aware/default.aspx.

SURFACE INJECTION FACILITIES

Typical surface facilities at an oil field can produce oil, water and natural gas. In addition, CO_2 and H_2S are produced in "sour" oil fields. A significant amount of the injected CO_2 is produced in CO_2 EOR operations like at Bell Creek. Each of these fluids can be used on-site, injected, or otherwise managed for offsite disposal and/or sale. The specific products from any oil field depend on the level of processing that is employed, which varies based on site-specific economics and conditions. At a CO_2 EOR operation, after separating the gas from oil and water, there are three typical approaches for managing it: 1) full-stream reinjection, which requires only dehydration and compression; 2) partial processing, which adds partial recovery of the C4+ hydrocarbons to the treatment train for full-stream reinjection; and 3) full processing, in which natural gas liquids (NGLs) and methane are also recovered from the gas, yielding a purer CO_2 stream for reuse. The Bell Creek EOR facility follows a scheme in which both the water and CO_2 that are separated from the produced oil are reinjected. Water is disposed of in a deeper formation or is used to pressurize portions of the field prior to CO_2 injection, to continue waterflood operations, or during water alternating gas (WAG) EOR activities. Fluids from individual wells are transported through flow lines and enter the header system of the production manifold in the manifold building. From the production manifold, the commingled stream flows to the process building for separation. Oil is piped to oil storage and sales tanks, and water is piped to temporary water storage tanks prior to being pumped back to the field for reinjection. CO_2 is piped to the compressor building where it is pressurized and then sent to the manifold building where it is combined with newly purchased CO_2 for reinjection into the oil reservoir. Water and CO_2 are distributed to the field through injection manifolds. An aerial view of the surface facilities associated with these activities at Bell Creek is shown in Figure 8-1.

Methods used by Denbury to plan, construct, and operate the Greencore pipeline for EOR may also apply to CO_2 transport for future CCS projects. Likewise, many of the surface facilities associated with CO_2 EOR are similar to those that would be needed for storage of CO_2 within any secure geologic formation. For this reason, the improved understanding of infrastructure requirements for CO_2 transportation and surface processing that has been gained as part of the Bell Creek demonstration test, along with many of the lessons learned from this EOR operation, will likely be extremely valuable to all future CCS projects.

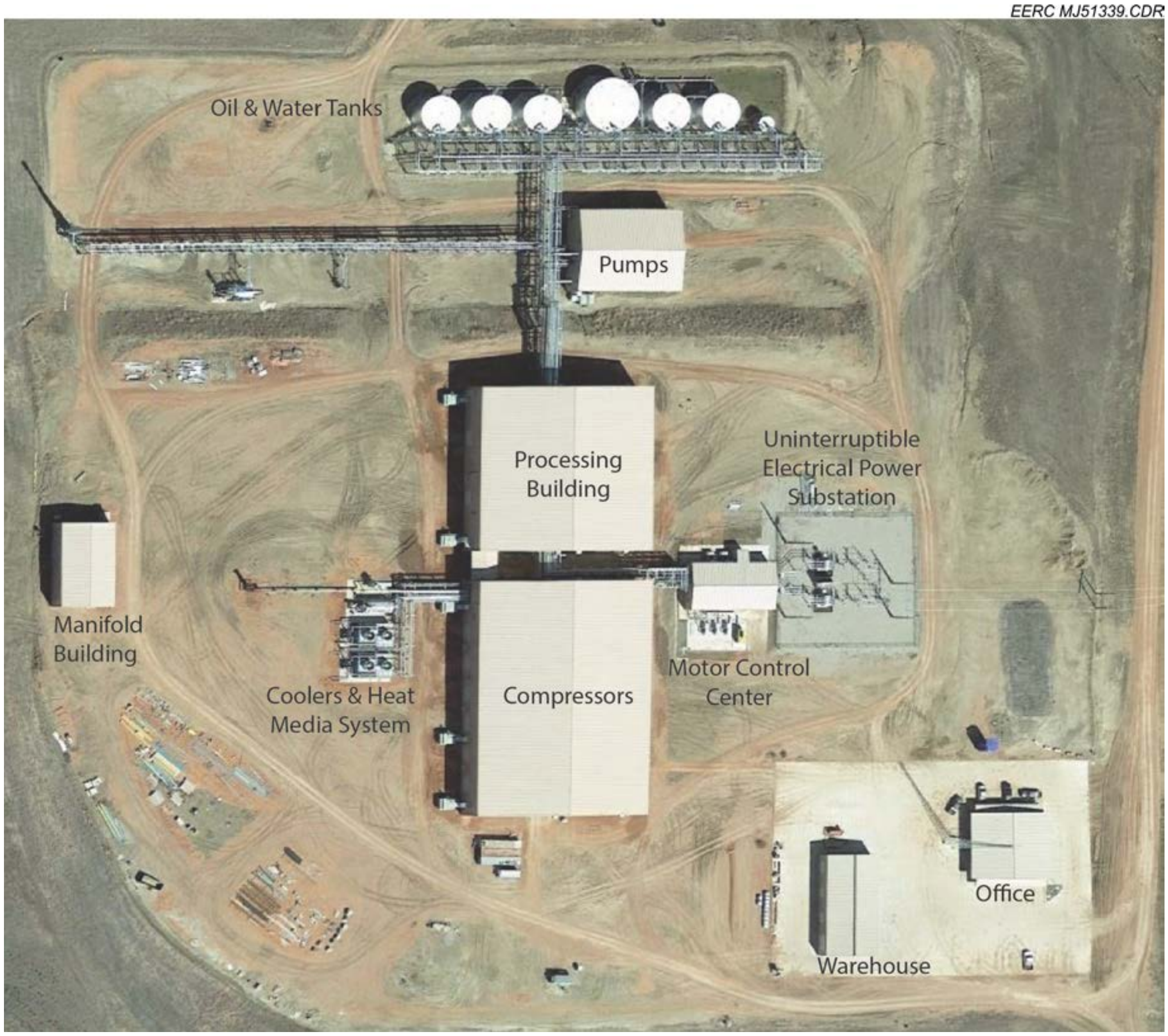

Figure 8-1. Bell Creek surface facilities (Denbury Resources Inc., 2015).

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APPENDIX 9

TASK 9 – OPERATIONAL MONITORING AND MODELING

TASK 9 – OPERATIONAL MONITORING AND MODELING

INTRODUCTION

Task 9 activities of the Plains CO_2 Reduction (PCOR) Partnership at the Energy & Environmental Research Center (EERC) focused on planning, design, and collection of monitoring data sets, as well as reservoir modeling and simulation, for the Bell Creek and Fort Nelson Phase III demonstration tests. The primary goals of these activities were to 1) verify that CO_2 injection operations did not adversely impact human health or the environment, and 2) define viable monitoring strategies for validating the storage of CO_2 that occurs during dedicated and associated CO_2 geologic storage projects.

Task 9 comprised two parts, one focused on the Bell Creek demonstration test and the other on the Fort Nelson feasibility study. The Bell Creek demonstration test involved a fully operating, commercial CO_2 enhanced oil recovery (EOR) operation, which continues to operate to date. The Fort Nelson feasibility study involved subsurface injection of a sour CO_2 gas recovered from a commercial natural gas-processing plant. However, this project did not proceed past the feasibility stage of development as it was terminated short of CO_2 injection because of a business decision made by the site operator. As such, Task 9 activities for this test, i.e., implementation of operational monitoring and reservoir modeling and simulation, were not executed in their entirety.

BELL CREEK MONITORING AND MODELING

Operational Monitoring

Monitoring of the Bell Creek oil field during CO_2 EOR operations (i.e., operational monitoring) included measurements necessary to provide assurance of the integrity of CO_2 storage, guide efficient and cost-effective EOR operations, and validate modeling predictions of CO_2 behavior in the subsurface to inform the development of long-term monitoring and operational plans. Operational monitoring consisted of:

- Downhole pressure and temperature monitoring at a dedicated monitoring well.
- Analysis of injection and production fluids.
- Monitoring of injection and production flow rates.
- Repeated pulsed-neutron log (PNL) campaigns.
- Repeated seismic survey monitoring.
- Analysis of near-surface soil gas and groundwater samples.

The operational monitoring strategy at Bell Creek initially mimicked the baseline monitoring plan. However, as operations progressed and more information was collected regarding the storage complex and behavior of injected CO_2, the monitoring plan and schedule were modified accordingly. For example, sampling of a wellbore and analysis of the collected fluid samples were eliminated after it was determined that the wellbore was within the CO_2 plume, since these analyses no longer provided value-added information to the monitoring program. For this reason, it is critical that an operational monitoring strategy be dynamic in nature to accommodate the continuously evolving risk and operational profile of a storage project.

Goals of an operational monitoring program typically include demonstration of secure CO_2 storage; tracking vertical and lateral movement of fluids and pressure; validating and improving long-term simulation forecasts of CO_2 storage capacity, efficiency, and utilization; informing operational improvements; and understanding the long-term distribution and containment of the injected CO_2 (Botnen and others, 2016). The selection of monitoring technologies is affected by a number of site- and project-specific considerations, typical examples of which include the following:

- Site-specific geology – Geology of a site may limit the monitoring technologies that are suitable for the site. For example, seismic measurements may not be as effective for a storage complex that has a thick overlying formation consisting primarily of salt.

- Project-specific risk assessment – Site-specific project risk assessment will identify individual technical risks that will need to be addressed by a site operator. Monitoring of these risks will dictate the collection of specific monitoring data. For example, technical risks associated with the lateral subsurface movement of CO_2 beyond the storage reservoir will affect the location and nature of subsurface monitoring activities.

- Project-specific data quality requirements – Accuracy and precision of monitoring data that are required for the site, which are driven by the technical risks of concern along with input data needs of the geologic models and reservoir simulations, will affect the selection of monitoring technologies. Of particular importance is the spatial and temporal resolution of the data that are provided by the different monitoring technologies.

- Regulatory requirements – Federal, state/provincial, and local regulations will likely specify the conduct of specific monitoring activities.

- Stakeholder/landowner concerns – The local community may have areas of concern that need to be addressed by the monitoring plan. For example, avoiding potential impacts to local underground sources of drinking water (USDWs) is often a concern of potentially affected landowners.

- Budget considerations – Collection of multiple rounds of monitoring measurements over the duration of the project (perhaps 20 years or longer) may make certain monitoring technologies cost-prohibitive.

The Bell Creek project employed numerous monitoring technologies for observing the near-surface and deep subsurface environments (Hamling and others, 2013; Glazewski and others, 2018). Geophysical surveys and PNLs, which are two applications that provided significant value to the monitoring and modeling program used at Bell Creek, are highlighted below.

Pulsed-Neutron Logs. PNLs measure the vertical distribution of CO_2 and other fluids in the near-wellbore region. This information provides a calibration point for simulation models that are used to predict the movement of CO_2 and other fluids during injection operations. Specifically, PNLs provide a quantitative assessment of liquid–gas saturations when operated in sigma mode and a quantitative measurement of water, oil, and CO_2 saturations when operated in the saturation (inelastic capture) mode (Schlumberger, 2007). PNLs also provide data that are useful for detecting CO_2 migration out of the storage complex and accumulation in overlying formations transected by the wellbore.

For associated storage of CO_2 that occurs in projects like Bell Creek, PNLs are particularly useful as they can be deployed across multiple wellbores for monitoring of CO_2 breakthrough along with changing oil and water saturations. These data are valuable for optimization of EOR operations, as well as monitoring of associated CO_2 storage. PNLs also help tune and calibrate geologic models, identify geologic formation tops, and enhance seismic survey interpretations.

Beginning in June 2013, 92 baseline and repeat/monitor PNL surveys were acquired in 45 wells in Bell Creek Field (Figure 9-1) (Jin and others, 2017a). Thirty-three baseline PNLs and seven repeat PNLs were used to discern formation top depths and thicknesses from the reservoir to the surface throughout developed geologic models. Changes in fluid saturations for CO_2, water, and oil were identified through the repeat logs and incorporated into the model. In addition, a reference model was created to serve as a repository for all relevant Bell Creek data used in the modeling and simulation activities (e.g., field and processed logs, core analyses, structural tops, cultural/political boundaries, completed simulation results, and ground surface elevation from lidar measurements). The Bell Creek reference model was then updated with any new PNL and seismic data collected. Seventeen PNLs were acquired late in 2015, providing both baseline characterization data and repeat/monitor data used to delineate fluid saturation changes. The Bell Creek reference model was further updated with 11 new repeat/monitor pulsed-neutron logs in early 2017. The combined PNL campaigns therefore contributed large amounts of data to various investigations, such as monitoring CO_2 breakthrough between production and injection wells, improving the Bell Creek monitoring, verification, and accounting (MVA) program by monitoring saturations in overlying formations, calibrating history-matching efforts during dynamic simulation, and updating reservoir properties.

Geophysical Surveys. While wellbore-based measurements provide information about near-wellbore geologic features and properties, interpolating geologic characteristics between wells may be challenging (Glazewski and others, 2018). Geophysical surveys, such as surface-based 2-D and 3-D seismic surveys, provide a means of integrating wellbore measurements and developing a broader interpretation about spatial variations throughout the storage formation (Glazewski and others, 2018). Baseline surveys, acquired prior to CO_2 injection, provide enhanced characterization of the reservoir and serve as a benchmark for comparison of subsequent operational surveys (Salako and others, 2017). Seismic surveys collected during the operational phase of the Bell Creek project provided the ability to estimate the boundary of injected CO_2 plumes around CO_2 injection wells. In addition to contributing data to the operational-phase monitoring program, seismic data allowed for tuning and calibration of geologic models, refining history matching in simulations, and aiding EOR operations. Seismic surveys are data-, time-, and capital-intensive, but in the case of the Bell Creek project they provided more than enough value to warrant continued investment during the operational phase.

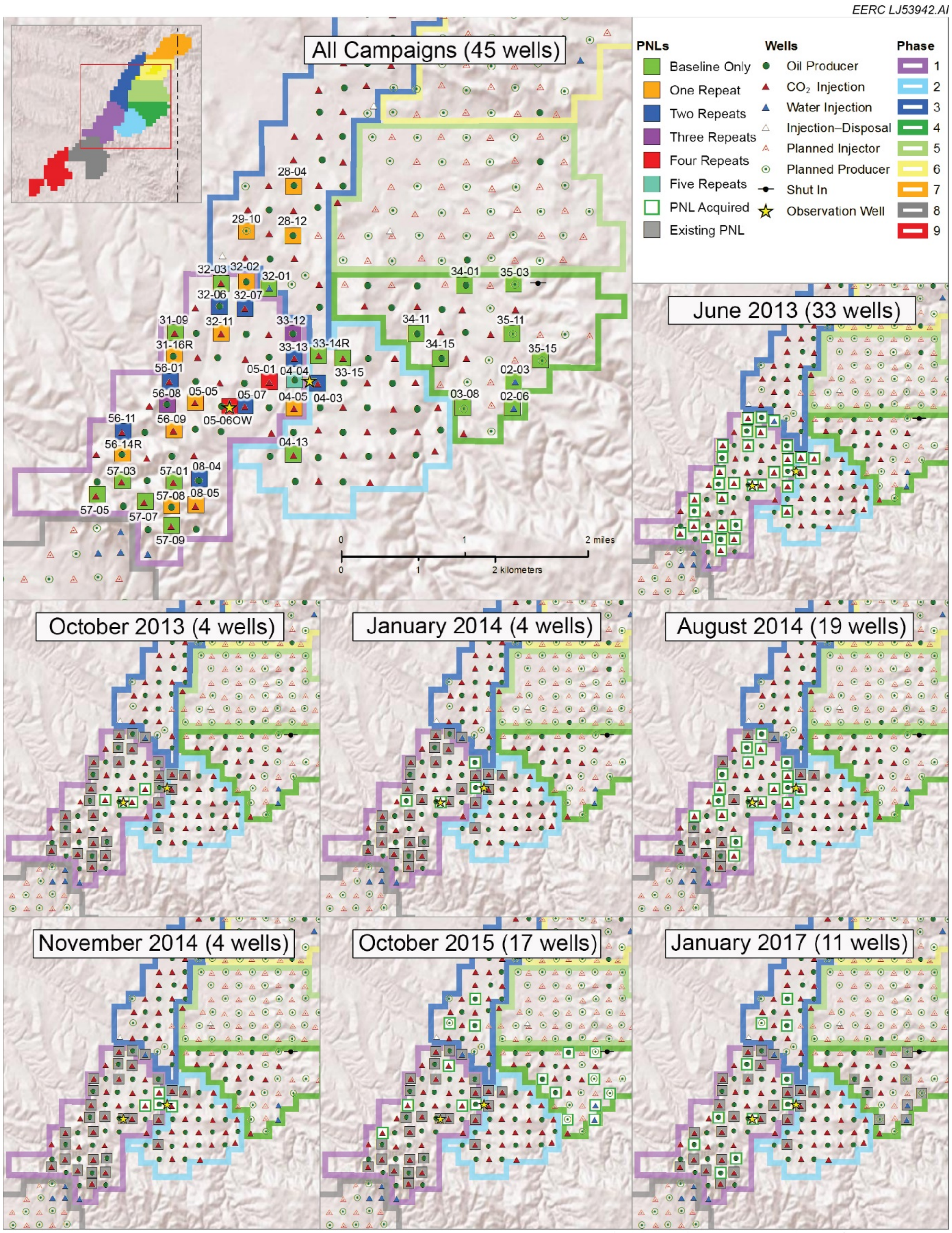

Figure 9-1. Bell Creek Field map showing where baseline and repeat/monitor pass PNLs have been collected since 2013 and also which wells were logged in each campaign (Jin and others, 2017a).

For example, a three-dimensional (3-D) surface seismic survey was acquired in 2012 prior to the start of CO_2 injection. This baseline survey provided detailed information that enhanced the characterization of the reservoir and served as a benchmark comparison for two subsequent surface monitor surveys acquired in 2014 and 2015. The monitor surveys, acquired after CO_2 injection had been implemented in different field development phases, were used to create "difference images" to track where the injected CO_2 had migrated to within the reservoir at the time of the survey. Maps of the seismic amplitude changes associated with injected CO_2 produce powerful images that allow for detailed interpretation of the injection zone, providing significant additional information on permeability barriers and flow channels that were used to refine the characterization, update the geologic models to improve predictive simulations, and help determine the ultimate fate of injected CO_2 (Figure 9-2).

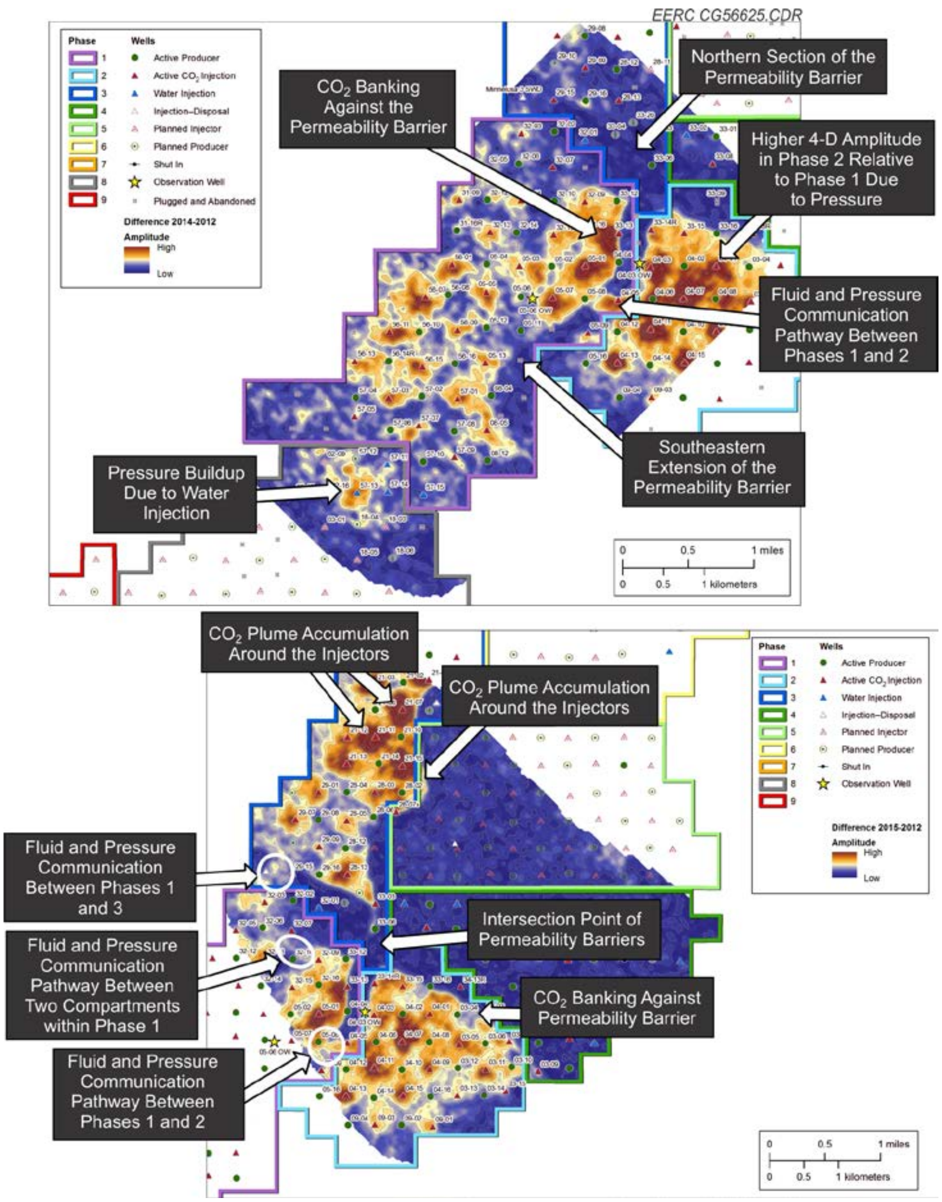

Figure 9-2. Summary of the 2012–2014 4-D amplitude difference map interpretation (top), and an annotated 4-D difference map from the 2015 monitor (bottom) (Salako and others, 2017).

The expanded seismic campaign at Bell Creek has provided a means to measure and image physical properties throughout the geologic section on a fine grid over the field that has aided geologic characterization. 4-D analysis improved the understanding of the reservoir heterogeneity and improved the geologic model that was generated using interpretation results from the 2012 baseline data (Burnison and others, 2014). CO_2 acted as a tracer and helped illuminate geobodies in the 4-D data by delineating permeability barrier boundaries that were not resolved with 3-D baseline data. This illumination gave better insight about the location, extent, and effectiveness of these permeability barriers (Salako and others, 2017).

Simulation of Phases 1 and 2 of the Bell Creek Oil Field

Geologic models and reservoir simulations were updated using operational monitoring data such as 4-D seismic surveys, PNLs, and production/injection rates.

Static geologic model realizations with the mean original oil in place (OOIP) value were exported to Computer Modelling Group Ltd.'s (CMG's) Builder software to construct a reservoir simulation model. Pressure, volume, temperature (PVT) data, relative permeability data, and well production/injection history were brought into Builder to begin the process of building the dynamic reservoir model. Fluid flow simulations were performed using CMG's GEM, a general compositional and unconventional reservoir simulator. The dynamic reservoir model with a comprehensive data set incorporated can accurately simulate the reservoir's pressure and fluid mobilization response to injection and/or production processes.

These updates improved both simulation efficiency as well as accuracy of performance predictions. More specifically, integration of 3-D and 4-D seismic data and PNLs and their correlation with legacy well logs and core analyses yielded a revised geologic interpretation (Bosshart and others, 2016; Jin and others, 2016a) that identified seven geobodies (i.e., geologically similar areas) within the Bell Creek Sand member. These geobodies were incorporated into an updated geologic model (V3). This model substantially redefined and reoriented the depositional model, which led to an improved simulation of the storage formation. These improvements would likely not have been possible without the additional monitoring data that were collected to monitor associated CO_2 storage.

Individual simulations of two of the Bell Creek phases of development (Phase Areas 1 and Phase Area 2), west and east of the "NS Channel" geobody indicated in Figure 9-3 (medium blue), showed that the two simulations could capture overall flow behavior and the general production profile in the field. However, the simulations were not able to account for fluid communication and pressure relationships between the development areas. The 4-D seismic survey difference display map clearly revealed two distinct permeability barriers and a narrow hydraulic link between the two project phases, as shown in Figure 9-4 (Salako and others, 2017). With this knowledge of the location of hydraulic connectivity, the simulation model was refined to improve history matching and enhanced oil recovery (EOR) performance prediction. A combined Phase Areas 1 and 2 model was developed based on the updated geologic model and 4-D seismic data, and new simulations resulted in an improved history match of the water cut in the two phases (Figure 9-5). This effort demonstrated that the refined reservoir simulation model, aided by seismic survey data, was capable of satisfactorily reproducing reservoir behavior.

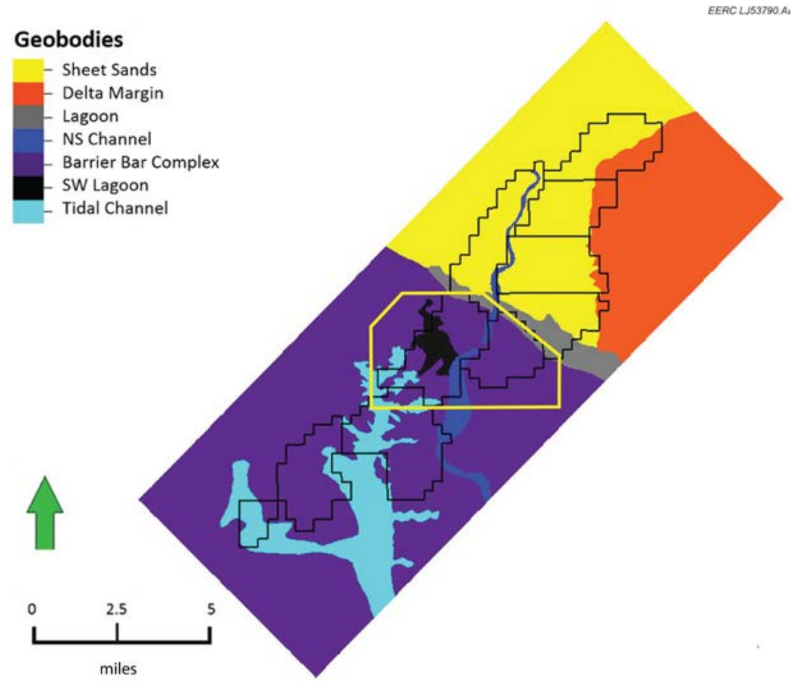

Figure 9-3. Distribution of geobody regions within the Bell Creek Sand Member (Jin and others, 2016a)

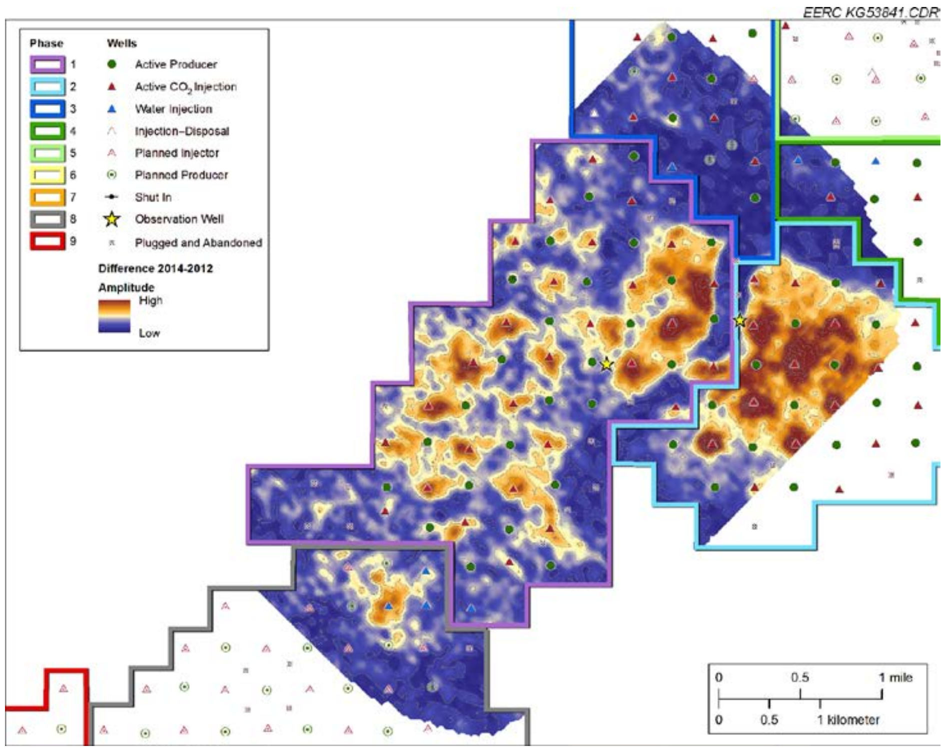

Figure 9-4. Time-lapse difference of 4-D seismic surveys conducted in Phase Areas 1 and 2 of the Bell Creek oil field in September 2012 and November 2014. (modified from Salako and others, 2017).

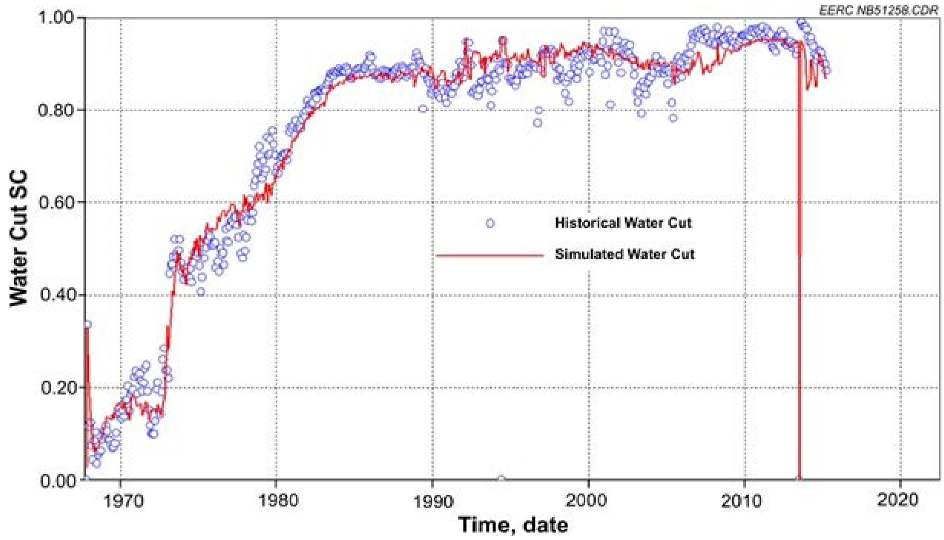

Figure 9-5. Water cut history match results for Phase Areas 1 and 2 of the Bell Creek oil field using the refined reservoir simulation model (Jin and others, 2016a).

Large-Scale Simulations of Phases 1 Through 4 of the Bell Creek Oil Field

In the Bell Creek Field, fluid flow simulations were used to investigate CO_2 EOR and associated storage performance. These simulations were especially valuable for prediction of fluid flow behavior in a reservoir with a high degree of heterogeneity, as illustrated by the Bell Creek well logs in Figure 9-6. To date, three large-scale simulation models have been developed for Phase Areas 1–4 following the field CO_2 injection schedule. By matching production/injection data in the field and predicting future performance of various flooding schemes, simulation results provide a meaningful supplement to the operational monitoring program.

Gas Injection and Production Rates. Figure 9-7 shows gas injection and production rates in the Bell Creek oil field since May 2013, when CO_2 injection began. The gas production rate increases steadily after CO_2 is injected for 9 months. As of September 2017, just over 3000 MMscf (i.e., more than 153,000 tonnes) of gas was produced at the surface each month. Based upon reservoir and fluid properties, multiple-contact miscible flooding occurs in the field. In the miscible flooding process, CO_2 reduces oil viscosity, swells oil volume, vaporizes and extracts hydrocarbons from oil, and develops miscibility with the oil under reservoir pressure and temperature (Shyeh-Yung and Stadler, 1995; Al-Wahaibi, 2010; Alvarado and Manrique, 2010; Hamouda and Tabrizy, 2013; Jin and others, 2016b, 2017b). Therefore, CO_2 that is produced at the surface with the oil always contains some level of hydrocarbon impurities.

Hydrocarbon Impurities Detected in CO_2 Recovered for Reinjection. As part of reservoir-monitoring efforts, CO_2 that is recovered for reinjection is sampled and analyzed periodically using gas chromatography to observe the change in composition of the gas. Figure 9-8 shows the impurities found in the recovered CO_2 and their change in concentration over time. It is clear that the main impurity is CH_4, which varies from 1.5 to 5 mol% during the flooding

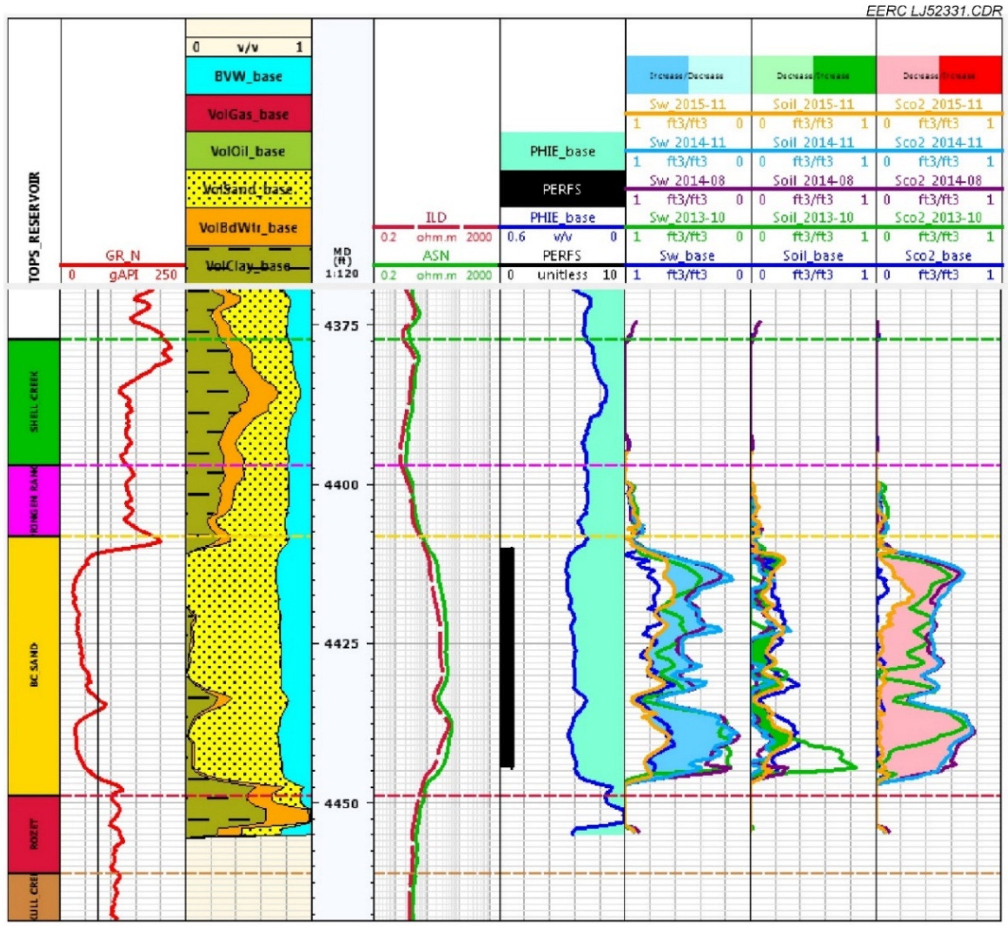

Figure 9-**6**. Well logs show the heterogeneity of the Bell Creek reservoir.

process. A slight amount of other light hydrocarbon components (C2–C5) is also present; however, their quantities are smaller by a factor of ~10 compared to CH_4. For instance, an illustrative analysis of recycled gas revealed a composition comprising 96.20 mol% CO_2, 3.43 mol% CH_4, and 0.36 mol% of other minor constituents.

Simulation of the Effects of Impurities in Recovered CO_2 on EOR Performance and Associated Storage. Analyses of bulk gas physical properties and measurement of gas–oil minimum miscibility pressures (MMPs) clearly showed that CH_4 has significant effects on the properties of the CO_2 stream (Jin and others, 2016a). However, exactly how the impurities may impact CO_2 EOR and associated CO_2 storage performance also depends on other factors such as geologic conditions, reservoir and fluid properties, and modes of EOR operation (Gardner and Ypma, 1984; Pande, 1992; Thomas and others, 1994; Afonja and others, 2012; Jiang and others, 2012; Yin and others, 2014). A large-scale simulation model covering Phase Areas 1 and 2 was selected to simulate reservoir performance of EOR operations with injection of produced CO_2 in the field. A complete history match was conducted for the study area beginning with primary production and through the stages of waterflooding and CO_2 flooding. History-matching results demonstrated that the model was able to capture flow dynamics in the reservoir.

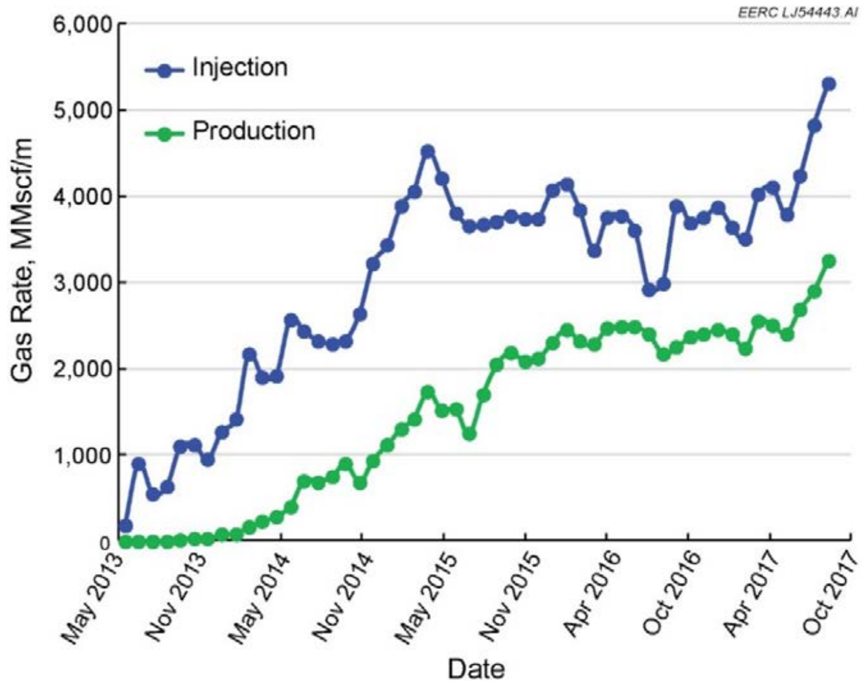

Figure 9-7. CO_2 injection and production rates during the CO_2 EOR process.

Simulation of the effect of impurities on oil recovery and associated storage provided the following results:

- Simulation of effect of impurities on oil recovery. Production history clearly showed that CO_2 EOR activities effectively produced oil in this area of the site; however, gas production rate increased rapidly as flooding proceeded. Based on test results for produced CO_2, a considerable amount of impurities was being injected into the reservoir. To evaluate the impact of this recycle gas injection on oil production, a set of predictive runs was performed using the history-matched model. The water alternating gas (WAG) injection approach was used to conform to actual field operation. The same gas and water injection rates were used for all cases, which means that the volume of fluids injected into the reservoir was identical at standard pressure and temperature. Reservoir pressure was maintained around 2500 psi in all cases, and the period of operation was set to 45 years (2015–2060), which is comparable to the expected length of a WAG operation. Figure 9-9 shows oil recovery performance for WAG operations using recycled gas injection with varying impurity content. The dashed line in the figure clearly indicates that pure CO_2 (impurity mol% = 0) does not yield the best oil recovery factor over the 45-year operating period; rather, recycled gas injection with 5 and 20 mol% impurities is predicted to result in more oil production than that of pure CO_2 injection. The MMP values vary from approximately 1410 psi for 0 mol% CH_4 to about 4080 psi for 100 mol% CH_4 in the mixture. The results indicate miscible gas flooding may still be attainable with up to 30 mol% CH_4 in the recycled gas stream if the reservoir pressure is maintained at or above 2500 psi. Oil recovery appears to decline after exceeding 30 mol% of impurities in the injected CO_2. When the impurity level exceeds 40 mol%, the flooding changes from miscible to immiscible, which leads to a significant reduction in flood efficiency (Jin and others, 2018).

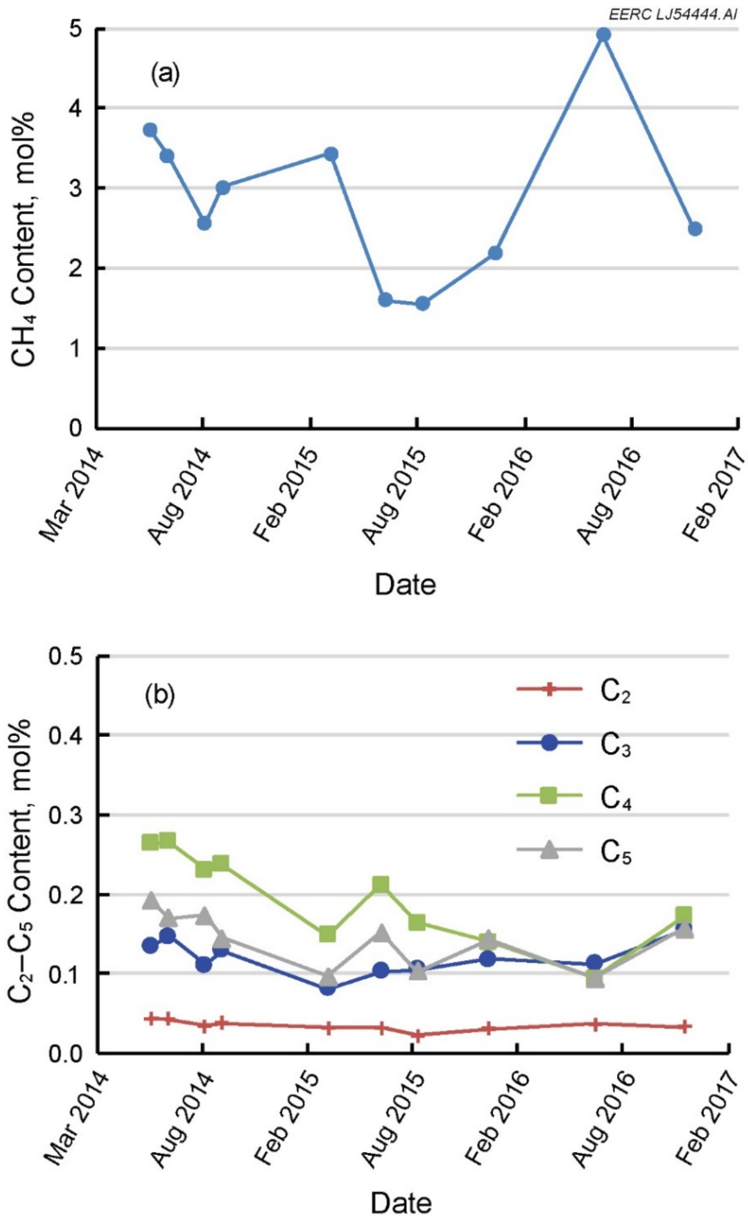

Figure 9-8. Content of hydrocarbons in the produced CO_2 stream: a) for CH_4 and b) for C2–C5.

- Simulation of effects of impurities on associated storage. Figure 9-10 illustrates the simulated impact of the major impurity, methane (CH_4), on associated CO_2 storage in the reservoir and predicts that, as expected, pure CO_2 injection results in the greatest amount of associated CO_2 storage. Storage efficiency is predicted to decrease with increasing impurity content. The phase behavior of the recycled gas changes significantly with the increase of CH_4 content. Because CH_4 is the dominant component in the impurities and it is much less condensable than CO_2, the impurities have the effect of increasing the bubble-point pressure and decreasing the critical temperature of the recycled CO_2 stream.

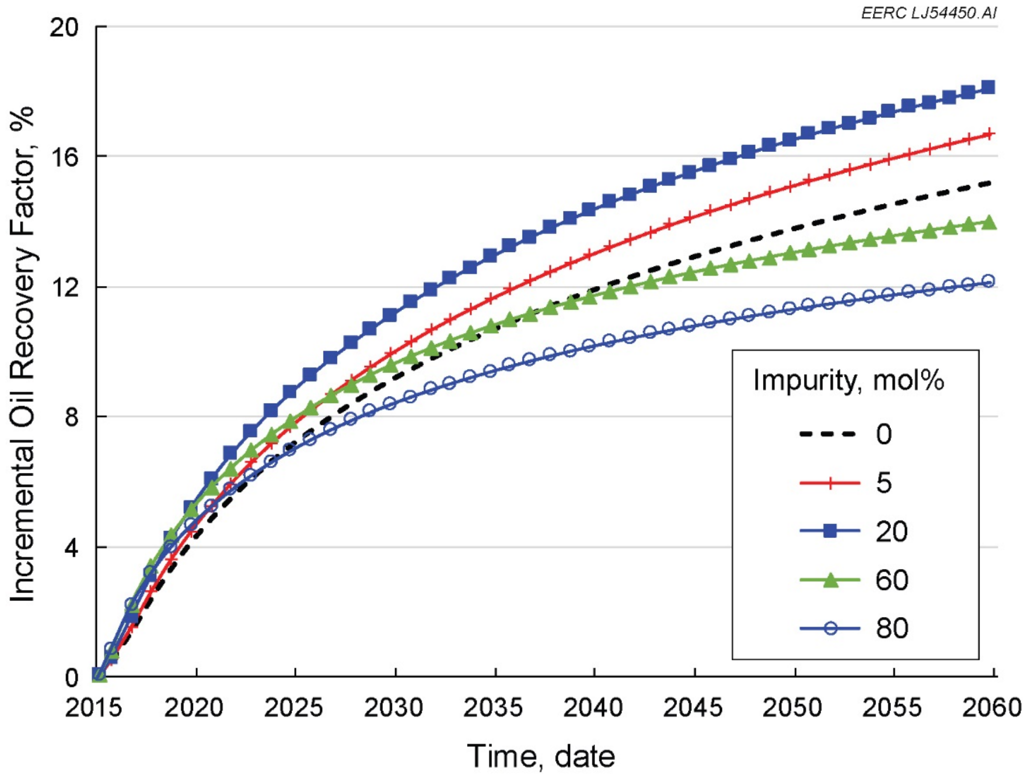

Figure 9-9. Comparison of oil recovery factor for WAG operations using recycled gas injection with varying impurity content.

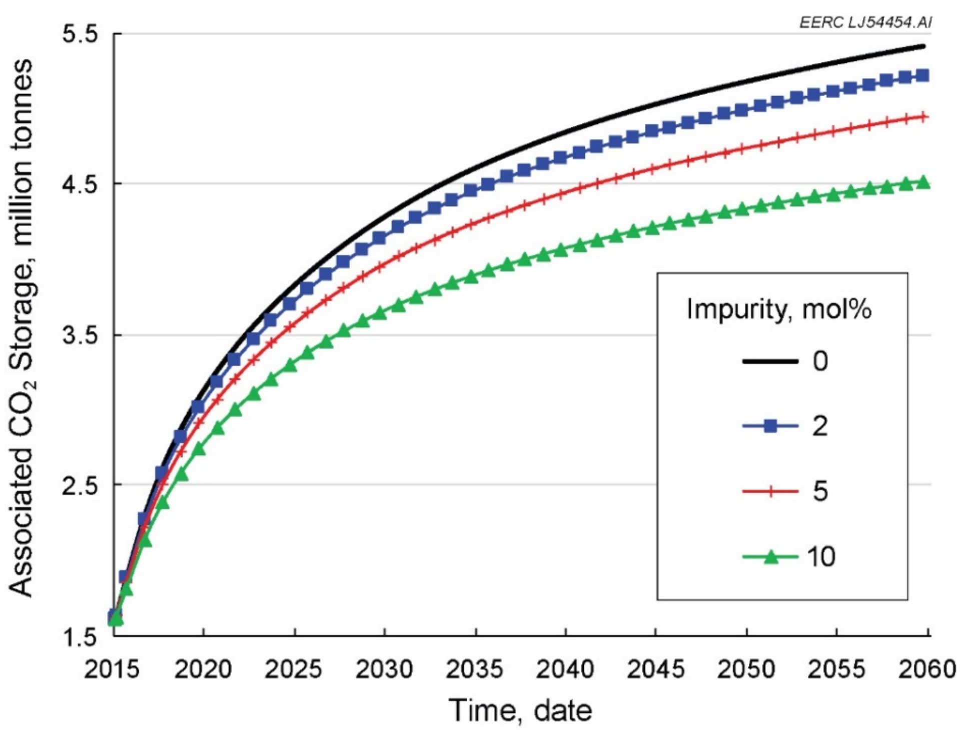

Figure 9-10. Associated CO_2 storage performance for recycled gas injection with varying impurity content.

As a result, a higher content of impurities in the gas shifts theboundaries of the phase diagram to higher pressures, implying a higher reservoir pressure is required to maintain the CO_2 in a dense phase. Figure 9-10 also indicates that the performance of associated CO_2 storage is quite sensitive to the content (amount) of impurities in the recycled CO_2, since CH_4 is less compressible and thus occupies more reservoir pore volume than CO_2 under the same reservoir conditions. However, based on field measurements of the concentrations of impurities in the produced CO_2, actual impurity content in recycled gas is less than 5 mol% (i.e., typically around 3 mol% for the majority of the time). Therefore, our simulations predict that approximately 5 million tonnes of associated CO_2 storage will occur in the targeted study area of the reservoir over a 45-year period during the application of CO_2 EOR at the site.

BELL CREEK LIFE CYCLE ASSESSMENT

Life cycle assessments (LCAs) were performed on two case studies involving production of oil at the Bell Creek oil field using CO_2 EOR. In one case study, CO_2 was sourced from a coal-fired power plant (Case 1, Azzolina and others, 2016) and in the other, it was sourced from a natural gas-processing plant (Case 2, Jensen and others, 2018). System boundaries of these LCAs were also different, with Case 2 stopping at production of oil while Case 1 extended the system boundary to include off-site transportation of oil, its refining, and end use of refined products. In both cases, greenhouse gas (GHG) emissions associated with oil produced via CO_2 EOR were compared to conventional methods of oil and/or natural gas production, yielding the following results:

- Comparison of Case 1 LCA results with production of oil using conventional methods revealed that crude oil produced from CO_2 EOR in the Bell Creek oil field, where the CO_2 is sourced from a coal plant, results in lower GHG emissions than production of oil using conventional methods. This suggests that CO_2 EOR provides one potential means for addressing the energy demand–climate change conundrum by simultaneously producing oil to meet growing energy demand while reducing GHG emissions to the atmosphere.

- Comparison of LCA results from Case 2 to GHG emissions from a benchmark system that separately produced natural gas and oil via conventional methods indicated that GHG emissions from Case 2, a coupled natural gas–oil energy system, produced natural gas and oil with lower life cycle GHG emissions, demonstrating the potential positive impact of linking energy processes to overall GHG emissions.

In both studies, LCAs were performed using a Microsoft Excel® spreadsheet model developed by the EERC. This model uses emission factors from peer-reviewed literature and the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL). In addition, results of other LCA tools, e.g., Argonne National Laboratory's "Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation" model, known as the GREET model, were also examined as part of the LCA analyses.

FORT NELSON MONITORING AND MODELING

From 2009 to 2014, Spectra Energy Transmission (SET) and the PCOR Partnership collected baseline characterization data on potential storage formations and their respective sealing formations in the Fort Nelson area in northeastern British Columbia, Canada. Those data were used to create static petrophysical models of potential storage reservoirs and to conduct dynamic reservoir simulations of potential injection scenarios. Characterization data and modeling results were used to perform a site-specific project risk assessment of potential CO_2 injection scenarios, and a draft MVA plan for a hypothetical injection scheme was developed using assumptions based on feasibility study efforts. The risk-based MVA plan monitored surface, near-surface, and deep subsurface environments and included specific monitoring technologies for collecting the baseline data necessary to address project risk and regulatory requirements.

Key elements for the Fort Nelson draft MVA plan were developed to address the guidelines in Canadian Standards Association (CSA) Standard CSA Z741-12, "Geological Storage of Carbon Dioxide" (Canadian Standards Association, 2012). The plan met or exceeded a majority of the CSA standard specifications, with potential deficiencies in topic areas that would not typically be addressed in the feasibility phase of a project but are more appropriately addressed after a project progressed to the design phase. The complete scope of activities performed as part of the Fort Nelson feasibility study was presented in a previous report (Sorensen and others, 2014).

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APPENDIX 10

TASK 10 – SITE CLOSURE

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INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership demonstration test conducted at Bell Creek is part of a commercial CO_2 enhanced oil recovery (EOR) operation, which will continue operating beyond completion of the test. For this reason, this task was focused on the closure of field-based research operations, which comprised primarily an investigation of monitoring, verification, and accounting (MVA) strategies. Detailed reporting of these site closure activities was provided in a site closure report (Glazewski and others, 2017); a brief overview of these efforts is provided here.

CLOSURE ACTIVITIES

Closure activities related to Bell Creek research efforts began in July 2016. In general, the Energy & Environmental Research Center (EERC) worked with the commercial partner and host site operator, Denbury Resources Inc. (Denbury), and pertinent landowners to repurpose and/or, where practical, abandon monitoring systems in place. If necessary, removal of monitoring equipment followed by remediation was also employed. More specifically, the following closure activities were completed:

- Field office support services, including satellite Internet and portable facilities (i.e., sanitation), were canceled and removed from the field site.

- A passive seismic array deployed in the dedicated monitoring well 04-03 OW (observation well) was powered down and idled in anticipation of decommissioning.

- Two groundwater-monitoring wells completed in the lowermost underground source of drinking water were idled and abandoned in place, effectively transferring operations to the associated landowner while maintaining access rights for future fluid sampling.

- A casing-conveyed pressure and temperature gauge system and distributed temperature system installed in the 05-06 OW well were put into minimum maintenance acquisition mode in anticipation of relinquishing operations to the site operator.

- Ten soil gas profile stations were idled in anticipation of either transferring operations to the site operator or removal and remediation.

Learnings derived from these field-based closure activities will have direct application to site closure for future CO_2 storage projects within the PCOR Partnership region. While this task addressed closure activities for monitoring activities at the site, Task 11 activities addressed monitoring that is required during both closure and the remaining postinjection period for a commercial storage site.

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APPENDIX 11

TASK 11 – POSTINJECTION MONITORING AND MODELING

TASK 11 – POSTINJECTION MONITORING AND MODELING

INTRODUCTION

Task 11 of the Plains CO_2 Reduction (PCOR) Partnership Program at the Energy & Environmental Research Center (EERC) addressed development of postinjection monitoring and modeling strategies for a commercial CO_2 geologic storage site. These strategies were based on lessons learned from commercial-scale operational monitoring and modeling activities that were conducted at the Bell Creek site under Task 9 (Appendix 9). Task 11 findings were detailed in two documents: 1) Deliverable (D) 55 – "Bell Creek Test Site – Development of Cost-Effective, Long-Term Monitoring Strategy" (Botnen and others, 2016), and 2) D73 – "Bell Creek Test Site – Monitoring and Modeling Fate of Stored CO_2 Progress Report" (Hamling and others, 2018). The report for Deliverable D55 examined the 5-year operational monitoring program deployed at the Bell Creek oil field to identify cost-effective monitoring protocols and long-term monitoring strategies for commercial storage projects with established injection. The report for Deliverable D73 then evaluated these strategies in combination with modeling and simulation results to enumerate specific strengths, limitations and costs, as well as their ability to address specific technical risks common to commercial CO_2 storage projects.

CLOSURE/POSTCLOSURE PERIODS

The postinjection period of a CO_2 storage site comprises two periods: closure and postclosure. The closure period is the period between the cessation of injection and the transfer of responsibility to a designated authority, should such a transfer occur (Canadian Standards Association, 2012). The postclosure period is the period that begins with the transfer of responsibility from the operator to the designated authority (Canadian Standards Association, 2012). The postclosure time frame is dictated by federal, state, and/or local regulations and can be as long as 50 years (U.S. Environmental Protection Agency, 2010).

Geologic modeling, simulation forecasting, and site monitoring provide the data and information required to achieve site closure. Specifically, data/information are used to:

- Account and validate CO_2 storage quantities at the end of the operational phase.
- Confirm that closed subsurface facilities and structures (e.g., wells) are securely abandoned.
- Ensure that surface facilities are appropriately abandoned and/or removed.
- Determine the facilities and access needed to execute postclosure-phase activities.
- Ensure that CO_2 remains securely stored in the reservoir with no evidence detected of significant impacts on the environment or other resources.

This same trio of activities also supports the postclosure period but with the intent of 1) ensuring that the fate of stored CO_2 within the subsurface environment is in accordance with model predictions; 2) providing assurance that stored CO_2 remains contained within the storage complex and does not pose a hazard to the environment or economic interests of other parties; and 3) providing evidence that the site is suitable for certification, final abandonment, and transfer of ownership and liability to the designated state agency.

CLOSURE/POSTCLOSURE MONITORING

The monitoring program for closure and postclosure periods represents an extension of the monitoring programs that have been implemented over the course of storage operations, i.e., baseline and operational monitoring programs. Monitoring of these postinjection periods provides the opportunity to take advantage of lessons learned from these previous monitoring efforts and to put into practice site-specific best practices for a postinjection monitoring program. Monitoring techniques included in the postinjection monitoring plan should be cost-effective, provide data for comparison to simulation predictions and for refining simulations, as needed, and/or to meet regulatory monitoring requirements. Ultimately, long-term monitoring of closure and postclosure periods should be accomplished using the lowest-cost monitoring approach that is capable of meeting regulatory requirements while certifying the site.

Monitoring efforts should be focused on observations showing that the CO_2 plume remains within the defined area of review to ensure compliance with regulations and/or the ability to achieve storage certification. Assuming that all of the wells are plugged and abandoned (or otherwise unavailable for monitoring data collection), the EERC determined that the most likely monitoring approach for the site would be a seismic survey to show the presence of CO_2, or lack thereof, at key locations within the area of review. A 2-D seismic line would be the most likely candidate to check for CO_2 presence. However, if a well or wells are still accessible, then pulsed-neutron logs (PNLs) may also be used in these wells to determine if CO_2 has reached that location.

The postinjection monitoring strategy should be evaluated regularly throughout the closure period and periodically during the postclosure period to ensure that technical performance and cost-effectiveness are maintained over time. For example, more cost-effective monitoring options may become available that were not available or did not exist at the time of development of the initial monitoring strategy. As such, provisions for assessing the applicability of emerging technologies and for obtaining approval from regulating authorities should be built into the long-term monitoring program. In addition, when possible, conversations with regulatory and/or certification authorities should emphasize the importance of establishing performance metrics for the postinjection monitoring program rather than a prescriptive list of required monitoring techniques and frequency of monitoring.

CLOSURE/POSTCLOSURE SIMULATION

Simulation objectives for the closure and postclosure periods are quite different from those for the operational phase of the project. For example, prediction of CO_2 enhanced oil recovery

(EOR) performance is one of the main tasks in the operational phase, as this performance is critical to minimizing operating costs and maintaining profitability of the field. Pattern optimization studies including gas recycle evaluations and assessment of different CO_2 injection strategies (i.e., continuous CO_2 injection [CCI] and water alternating gas [WAG] injection modes with various pressure/slug settings) are investigated to improve sweep efficiency. On the other hand, as part of closure/postclosure simulations, CO_2 injection has been terminated and EOR performance is no longer a focus. The focus of simulations covering the closure and postclosure periods is the behavior and fate of the stored CO_2. That said, it is important to recognize that while the quantity of CO_2 stored in the reservoir will no longer increase due to the cessation of CO_2 injection, pressure changes and movement of fluids will continue within the storage complex. Although undesirable, CO_2 movement (including leakage) outside the storage complex may occur, jeopardizing site certification and the liability transfer to the designated state agency.

The EERC performed a demonstration of reservoir behavior at the Bell Creek oil field in the closure/postclosure period using a history-matched simulation model encompassing two phase areas, i.e., Phase Areas 1 and 2, of the field. Simulations of two CO_2 injection scenarios, one CCI and one WAG, were run until a stable pressure and CO_2 saturation distribution was achieved in the reservoir. In both cases, the minimum bottomhole pressure constraint was set at 2300 psi for all production wells and the maximum injection pressure constraint was set at 2800 psi for all injection wells. Both CCI and WAG injection scenarios were then simulated from year 2016 to year 2060, followed by a complete well shut-in and a postinjection period of 1040 years (Peterson and others, 2017).

Simulation results predicted that approximately 12 million tonnes (Mt) of CO_2 will be trapped in Phase Areas 1 and 2 of the field following CCI. CO_2 in Phase Area 1 will move toward the eastern boundary of the phase over time, banking against the permeability barrier, as the reservoir has a 1°–2° dip to the northwest. A portion of the injected CO_2 will flow across the phase boundary into the Phase Area 2. However, the migration velocity will be very slow (especially after 340 years), and the shape of the CO_2 saturation front will not change significantly during the period from 700 to 1040 years, as shown in Figure 11-1. Compared to the CCI scenario, a smaller quantity (approximately 5 Mt) of trapped CO_2 was predicted for the WAG injection scenario. CO_2 migration velocity for this case would be similar to the CCI case, as illustrated in Figure 11-2. The simulation results for both the CCI and WAG injection scenarios clearly indicate the effectiveness of structural/stratigraphic trapping for CO_2 in the Bell Creek oil field over a long period of time.

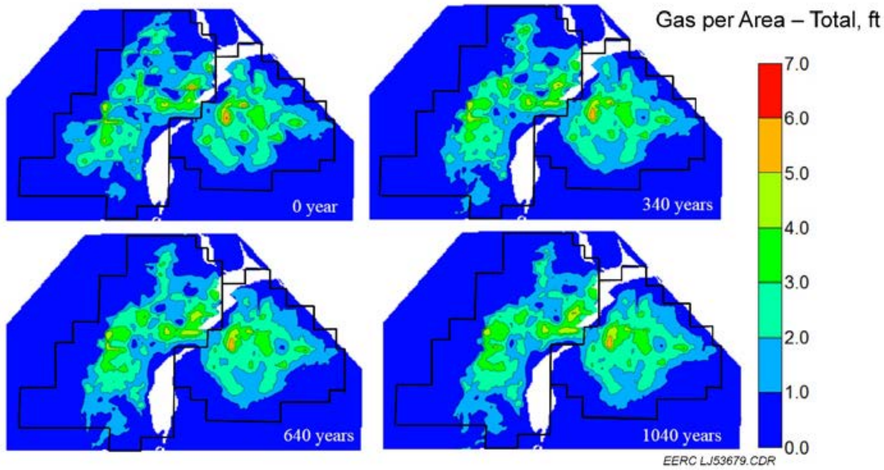

Figure 11-1. Post-CCI CO_2 saturation distribution through time in Phase Areas 1 and 2 of the Bell Creek oil field (Peterson and others, 2017).

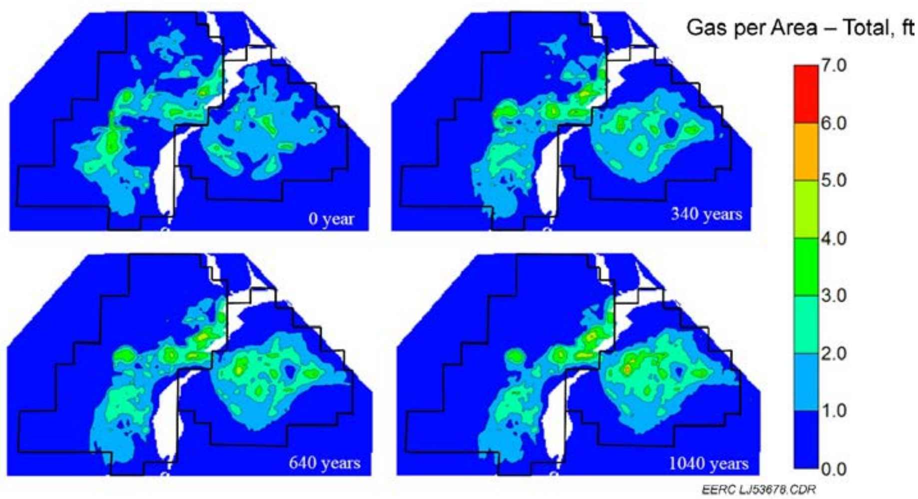

Figure 11-2. Post-WAG injection CO_2 saturation distribution through time in Phase Areas 1 and 2 of the Bell Creek oil field (Peterson and others, 2017).

If the Bell Creek project were to progress into a closure/postclosure phase, the simulation model described above would be revisited and potentially updated or refined based on observations obtained from monitoring data in a similar fashion to the operational phase.

CONCLUSIONS

Strategies for monitoring the postinjection period of a CO_2 storage project should be built using the information gathered and lessons learned from previous baseline and operational monitoring phases of the project. This monitoring effort should be combined with geologic modeling and simulation forecasting to provide the data and information that are required to achieve both site closure and final site certification and transfer of liability.

Based on the experience gained as part of the Bell Creek demonstration test, the following general conclusions can be made regarding postinjection monitoring and modeling:

- Monitoring efforts should be focused on observations showing the presence or absence of CO_2 at key locations in the subsurface to ensure compliance with regulations and/or the ability to achieve storage certification.

- Assuming accessible wells have been plugged, the most likely monitoring approach for a site would be a seismic survey to show the presence or absence of CO_2 at key locations in the subsurface. If wells are still accessible, then PNLs may also be used as a means of determining CO_2 saturation in the subsurface.

- Throughout the postinjection monitoring period, geologic models should be refined, if necessary, as more data become available through monitoring activities, such as PNLs, seismic surveys, or injection/production data, e.g., pressure and temperatures. At the same time, reservoir simulations should be used to predict the movement of CO_2 and other fluids in the reservoir to facilitate any modifications to the monitoring program, e.g., redeployment of existing monitoring technologies and/or deployment of new monitoring technologies.

- Simulation models, history-matched using historical production data and 4-D seismic survey interpretations, are useful for predicting long-term trapping of CO_2 in the reservoir. These results are required to demonstrate the stability of injected CO_2 in the subsurface, a necessary requirement for achieving regulatory certification of the site.

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APPENDIX 12

TASK 12 – PROJECT ASSESSMENT

TASK 12 – PROJECT ASSESSMENT

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership has achieved its Phase III mission through a series of 16 tasks. These tasks included 1) Regional Characterization; 2) Public Outreach and Education; 3) Permitting and NEPA Compliance; 4) Site Characterization and Modeling; 5) Well Drilling and Completion; 6) Infrastructure Development; 7) CO_2 Procurement; 8) Transportation and Injection Operations; 9) Operational Monitoring and Modeling; 10) Site Closure; 11) Postinjection Monitoring and Modeling; 12) Project Assessment; 13) Project Management; 14) RCSP WWG Coordination; 15) Further Characterization of the Zama Acid Gas EOR, CO_2 Storage, and Monitoring Project; and 16) Characterization of the Basal Cambrian System.

ANNUAL ASSESSMENT

Throughout Phase III, an annual assessment report (D57) was submitted each December under Task 12, presenting an update of activities from the previous DOE fiscal year (October 1 through September 30) (Steadman and others, 2009, 2010; Gorecki and others, 2011, 2012, 2014, 2015a and b, 2016, and 2018).

The annual report provided information regarding the following:

- Activities and accomplishments of each task
- Updated PCOR Partnership membership list
- Status of the project budget
- Updated Gantt charts for the current budget period
- Progress update of all Phase III deliverables and milestones, including due dates and actual completion dates
- Details of planned activities by task for the upcoming year
- Citations for products and publications from the fiscal year, including presentations, conference papers, and journal articles
- Summary of project-related travel completed during the fiscal year

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APPENDIX 13

TASK 13 – PROJECT MANAGEMENT

TASK 13 – PROJECT MANAGEMENT

INTRODUCTION

Project management activities during Phase III focused on ensuring that the technical scope of work was successfully executed both within budget and on schedule. The Plains CO_2 Reduction (PCOR) Partnership assembled an experienced technical and administrative project team to perform this task, led by the program manager (PM), who provided technical oversight and coordinated and integrated project activities. This team focused on completion of project milestones, preparation of high-quality project deliverables, and accurate and timely reporting of project results. To provide guidance, support, and an independent review of these activities, the PCOR Partnership also formed an external Technical Advisory Board (TAB), which has met on an annual basis since 2012.

One very important aspect of the project management task was the communication and dissemination of project results to the U.S. Department of Energy (DOE), PCOR Partnership project partners, and the technical community at large. This was achieved by convening annual project review meetings between representatives of the PCOR Partnership management team and representatives of the PCOR project partners and DOE project managers, along with giving numerous presentations at national and international technical meetings and conferences, distribution of project deliverables through a robust outreach program that included posting technical and other support materials on a PCOR Partnership Web site, and regular communication with other DOE researchers involved with the other Regional Carbon Sequestration Partnerships (RCSPs), the DOE national laboratories, and other DOE research groups engaged in CO_2 capture and sequestration.

More specifics regarding these project management activities are provided as follows:

- The PCOR Partnership PM and task leaders met regularly to report the progress of their tasks, discuss any issues and, if necessary, identify corrective actions to address them. Task leaders also provided the PM with written weekly updates, which included technical highlights (including trip reports), administrative (e.g., budget, staffing, etc.) and technical issues, new opportunities, and travel plans. Informal weekly updates were e-mailed to the DOE program manager. Monthly progress reports were submitted to the DOE program manager and were posted on the partners-only portion of the PCOR Partnership Web site. Quarterly progress reports, each including a milestone report, were submitted to DOE and the PCOR Partnership partners 1 month after the end of each calendar quarter.

- Under the umbrella of the RCSP Program, the PCOR Partnership worked with the other RCSPs to share technical findings and lessons learned at the regional level. Members of the PCOR Partnership attended the annual meetings of the other RCSPs and were active in working groups that involved other RCSP participants.

- Members of the PCOR Partnership attended and presented at all of the DOE Annual Contractor's Review Meetings, which were renamed in 2016 to the Mastering the Subsurface Through Technology Innovation & Collaboration: Carbon Storage & Oil & Natural Gas Technologies Review Meetings. A booth was featured at these meetings, which featured many of the technical work products of the PCOR Partnership.

- The PCOR Partnership continued to receive significant support and participation from its industry partners. Inquiries from interested organizations continued throughout Phase III of the program, increasing the number of stakeholders from the public and private sectors to over 120 participants. The membership, as of September 30, 2018, is listed in Table 13-1. Individual meetings and technical workshops were held with many of these partners, and a PCOR Partnership Membership Meeting was convened annually to report the progress of activities and present the path forward for future work.

- In addition to Best Practices Manuals (BPMs) that were generated as part of other project tasks, the PCOR Partnership published two BPMs under the program management task During the execution of Phases I–III of the project, the PCOR Partnership formalized an adaptive management approach (AMA) for the commercial deployment of CO_2 storage projects. A BPM was created to describe the concepts and application of the PCOR Partnership AMA (Ayash and others, 2017). In addition, a BPM was created that identified the key elements of a risk assessment for a CO_2 storage complex, defined the important risk management terminology and technical factors that are unique to the geologic storage of CO_2, and presented case studies that highlighted the experience of the PCOR Partnership with conducting risk assessments for both dedicated and associated storage projects in the PCOR Partnership region (Azzolina and others, 2017). The PCOR Partnership also played an active role in the review and revision of the best practices manuals (BPMs) that were developed for the DOE Carbon Storage Project.

- As required by DOE, the PCOR Partnership participated in independent technical reviews by internationally recognized outside experts of the Phase III program in 2011, 2013, and 2017, all of which were led by the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG). The review panel provided its comments and recommendations to DOE. Each time, as part of these reviews, the PCOR Partnership PM presented a technical summary of the project, which provided an update on PCOR Partnership activities, including how these activities were meeting the goals of the RCSP Program. This presentation was followed by a question-and-answer session and deliberations by the review panel. Recommendations from the peer review panel were provided by DOE to the PCOR Partnership following the review, and a formal written response to these comments was prepared and submitted to DOE.

Table 13-1. PCOR Partnership Membership Phase III (October 1, 2007 – present, inclusive)

- DOE NETL
- UND EERC
- Abengoa Bioenergy New Technologies
- Air Products and Chemicals, Inc.
- Alberta Department of Energy
- Alberta Department of Environment
- Alberta Innovates – Technology Futures
- ALLETE
- Ameren Corporation
- American Coalition for Clean Coal Electricity
- American Lignite Energy
- Apache Canada Ltd.
- Aquistore
- Baker Hughes Incorporated
- Basin Electric Power Cooperative
- BillyJack Consulting Inc.
- Biorecro AB
- Blue Source, LLC
- BNI Coal, Ltd.
- British Columbia Ministry of Energy, Mines, and Petroleum Resources
- British Columbia Oil and Gas Commission
- C12 Energy, Inc.
- The CETER Group, Ltd.
- Computer Modelling Group Ltd.
- Continental Resources, Inc.
- Dakota Gasification Company
- Denbury Resources Inc.
- Eagle Operating, Inc.
- Eastern Iowa Community College District
- Enbridge Inc.
- Encore Acquisition Company
- Energy Resources Conservation Board/Alberta Geological Survey
- Environment Canada
- Excelsior Energy Inc.
- Equinor
- General Electric Global Research Oil & Gas Technology Center
- Great Northern Project Development, LP
- Great River Energy
- Halliburton
- Hess Corporation
- Huntsman Corporation
- Husky Energy Inc.
- Indian Land Tenure Foundation
- Interstate Oil and Gas Compact Commission
- Iowa Department of Natural Resources
- Lignite Energy Council
- Manitoba Geological Survey
- Marathon Oil Company
- MBI Energy Services
- MEG Energy Corporation
- Melzer Consulting
- Minnesota Power
- Minnkota Power Cooperative, Inc.
- Missouri Department of Natural Resources
- Missouri River Energy Services
- Montana–Dakota Utilities Co.
- Montana Department of Environmental Quality
- National Commission on Energy Policy
- Natural Resources Canada
- Nebraska Public Power District
- North American Coal Corporation
- North Dakota Department of Commerce Division of Community Services
- North Dakota Department of Health
- North Dakota Geological Survey
- North Dakota Industrial Commission Department of Mineral Resources, Oil and Gas Division
- North Dakota Industrial Commission Lignite Research, Development and Marketing Program
- North Dakota Industrial Commission Oil and Gas Research Council
- North Dakota Natural Resources Trust
- North Dakota Petroleum Council
- North Dakota Pipeline Authority
- Omaha Public Power District
- Otter Tail Power Company
- Outsource Petrophysics, Inc.
- Oxand Risk & Project Management Solutions
- Peabody Energy
- Petro Harvester Oil & Gas
- Petroleum Technology Research Centre
- Petroleum Technology Transfer Council
- Pinnacle, a Halliburton Service
- Prairie Public Broadcasting
- Pratt & Whitney Rocketdyne, Inc.
- Praxair, Inc.
- Ramgen Power Systems, Inc.
- Red Trail Energy, LLC
- RPS Energy Canada Ltd.
- Saskatchewan Ministry of Industry and Resources
- SaskPower
- Schlumberger
- Scout Energy Management LLC
- Sejong University
- Shell Canada Limited
- Spectra Energy
- Suncor Energy Inc.
- TAQA North, Ltd.
- TGS Geological Products and Services
- Tri-State Generation and Transmission Association, Inc.
- Tundra Oil and Gas
- University of Alberta
- University of Regina
- WBI Energy, Inc.
- Weatherford Advanced Geotechnology
- Western Governors' Association
- Westmoreland Coal Company
- Wisconsin Department of Agriculture, Trade and Consumer Protection
- Wyoming Office of State Lands and Investments
- Xcel Energy

One outcome of note from the 2011 expert panel review was the recommendation to create a TAB to provide scientific and/or operational guidance to the PCOR Partnership Program. In response to this request, the PCOR Partnership requested, and was issued, a contract modification (No. 21 issued in September 2011) that authorized the creation of an advisory board under Task 13 (Project Management) of the statement of project objectives (SOPO). An advisory board, consisting of no fewer than five non-EERC advisors, was selected from among experts in the fields of carbon capture and storage (CCS) and enhanced oil recovery (EOR). The advisors had no term requirements or limits and served dependent upon availability. The PCOR Partnership greatly benefited from TAB recommendations and guidance since its inception. Annual face-to-face meetings, combined with shorter Webinars throughout the year, provided regular opportunities for

TAB to review and comment on the PCOR Partnership's activities from both technical and strategic perspectives. This consistent feedback provided an independent review by industry-leading experts and contributed to a more scientifically sound and robust research program. From the PCOR Partnership's perspective, these meetings were invaluable in guiding the technical components of the PCOR Partnership's work. For example, during a Webinar on soil gas- and groundwater-monitoring activities at Bell Creek, TAB recommended that the PCOR Partnership drill two deep groundwater-monitoring wells. The Bell Creek oilfield operator took this recommendation seriously and implemented it, resulting in a stronger overall monitoring program for the project. The following were the PCOR Partnership TAB members at the end of PCOR Partnership Phase III:

- Bill Jackson, BillyJack Consulting, Inc. (Chair)
- Stefan Bachu, Innotech Alberta
- Stacey Dahl, Minnkota Power Cooperative
- Jim Erdle, Computer Modelling Group, Ltd.
- Ray Hattenbach, industry expert
- Lynn Helms, North Dakota Industrial Commission
- Mike Holmes, Lignite Energy Council (LEC)
- Steve Melzer, Melzer Consulting
- Tom Olle, Lonestar Resources, Inc.

Former TAB members and their industry affiliations at the time of their participation on the TAB include Steve Whittaker (Commonwealth Scientific and Industrial Research Organization), Neil Wildgust (Global CCS Institute), and Mike Jones, LEC.

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APPENDIX 14

TASK 14 – REGIONAL CARBON SEQUESTRATION PARTNERSHIP WATER WORKING GROUP COORDINATION

TASK 14 – REGIONAL CARBON SEQUESTRATION PARTNERSHIP WATER WORKING GROUP COORDINATION

INTRODUCTION

The implementation of carbon capture and storage (CCS) to reduce atmospheric emissions of CO_2 from hydrocarbon-based power plants and other point sources will result in an increase in water demand (Klapperich and others, 2014). These additional water requirements will be driven largely by process changes, increases in makeup and cooling water requirements, energy demand for compression and transmission of captured CO_2, and the generation of replacement power to make up for parasitic load losses at power production facilities. At the same time, there is a potential to generate water during geologic storage of CO_2 if the withdrawal of water from the storage formation is used as a means to manage subsurface pressure and/or to increase the CO_2 storage potential of the formation. Depending upon the quality of this extracted water and the relative locations of the CO_2 sources and geologic storage site, extracted water may be used to supply the additional water needs created by CCS operations and, in some instances, to provide excess water for beneficial reuse in the region.

Many challenges must be addressed to meet the increased water demands associated with the commercial deployment of CCS technology. To identify and address these new water challenges, as well as the associated opportunities for water generation and reuse, a Water Working Group (WWG) was formed by the Regional Carbon Sequestration Partnerships (RCSPs) of the U.S. Department of Energy (DOE) in 2009 (Water Working Group, 2010). The WWG, which is led by the Plains CO_2 Reduction (PCOR) Partnership, consists of a team of experts from government, academia, and industry whose goal is to address stakeholder concerns regarding the potential interactions between commercial CCS facilities and local and regional water resources.

CCS–WATER NEXUS FRAMEWORK

The WWG developed a framework for the CCS–water nexus (Klapperich and others, 2014). This framework was based on a water management flow sheet, which evolved over time (Figure 14-1). As shown in Figure 14-1, the WWG focused on power generation and oil refining as the sources of CO_2 since they both represent primary targets for CCS. An examination of the CCS–water nexus for other industrial sources of CO_2 emissions such as ethanol production, cement production, or fertilizer production, to name a few, was beyond the scope of the WWG. However, the same approach and technical assessments conducted by the WWG for power generation/refining are applicable to the deployment of CCS at these other industrial sources.

As depicted in Figure 14-1, the CCS–water nexus comprises three primary components: 1) CO_2 capture, 2) CO_2 compression and transport, and 3) geologic storage of CO_2. The primary water impacts associated with each of these components are as follows:

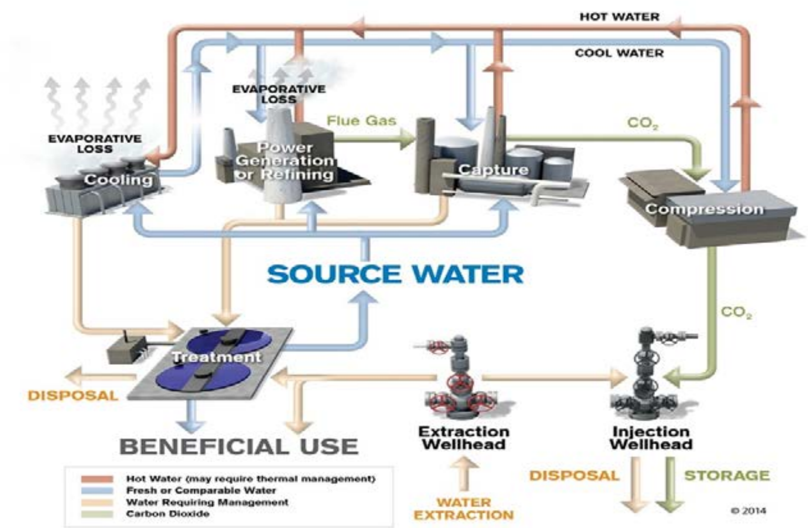

Figure 14-1. Deployment of CCS will result in an increase in water usage at carbon sources and may also generate water for beneficial use in proximity to storage sites. Blue arrows represent water withdrawn from surface water or groundwater sources, as well as water which may be returned to the original or a related source. Red arrows represent hot water sent to cooling facilities. Green arrows represent the flow of CO_2 through the system. Tan arrows represent water requiring some form of management (e.g., treatment) prior to its final disposition.

- <u>CO_2 Capture</u>: The implementation of CCS will likely increase freshwater withdrawals and consumption of the power industry to accommodate additional cooling loads resulting from the increase in energy output required to accommodate parasitic energy for new plants, as compared to the same plant without carbon capture technology. This increase has been estimated to be: 1) 90% for new subcritical and supercritical pulverized coal (pc)-fired power plants using amine-based CO_2 capture systems; 2) 76% for natural gas combined-cycle (NGCC) plants that also deploy the amine-based capture system; and 3) 45% for integrated gasification combined cycle (IGCC) plants that utilize the Selexol process for capture of CO_2 (Klapperich and others, 2014).

- <u>CO_2 Compression and Transportation</u>: Captured CO_2 is typically compressed and maintained above its supercritical pressure (72.8 atm or 1071 psia @ T_c of 88°F) during pipeline transport. A pressure of approximately 2200 psia is targeted to transport CO_2 a distance of 50 miles via a pipeline without the need for booster recompression stations. In one instance, a pressure of 2700 to 2964 psig was used in a pipeline to transport CO_2 over a distance of ~200 miles (Klapperich and others, 2014). This compression of the captured CO_2 consumes both energy (i.e., additional load for operating the compressors) and water (i.e., water for interstage cooling of the compressors), with estimates of the latter of approximately 0.01 gallons per additional kWh required to transport the captured CO_2 to its destination (Klapperich and others, 2014).

- Geological Storage of CO_2: In some instances, water will be generated during geological storage of CO_2 as formation water is actively removed from a storage reservoir during a process identified as active reservoir management (ARM). ARM may be employed for a number of possible reasons including increasing CO_2 storage volume of the reservoir, managing CO_2 plume migration, reducing cap rock exposure to CO_2, managing the pressure of the storage reservoir, and/or generating a new source of water for beneficial reuse at the surface. The quantity and quality of the water that is generated during ARM will be driven by many site-specific factors. In most cases, extracted water would be managed by direct injection into an appropriate overlying saline formation or formations. Indirect benefits may also be derived through the treatment and sale of extracted water, especially in those areas where water demands are excessive and water resources are limited.

Minimizing the net water consumption of CCS operations while at the same time ensuring that the injected CO_2 remains underground and does not migrate into underground sources of drinking water (USDWs) represents a key technical challenge during the commercial deployment of CCS.

WORK PERFORMED

The activities of the WWG were focused on achieving two primary objectives: 1) addressing stakeholder concerns regarding potential interactions of commercial CCS operations with local and regional water resources and 2) defining technical challenges and opportunities associated with managing the CCS–water nexus and facilitating technical transfer of research that was performed by the RCSPs to overcome challenges and exploit opportunities. An overview of specific stakeholder outreach and technical activities that were performed by the WWG since its inception in 2009 through the end of its tenure at the conclusion of calendar year 2017 are provided below:

- Multiple technology transfer vehicles, which included fact sheets, a WWG Web site, and a standardized WWG presentation, were developed to facilitate the transfer of WWG findings and observations to a variety of CCS stakeholders.

- Monthly conference calls and six annual meetings, which included invited speakers, were used to facilitate timely exchange and discussion of information among WWG representatives of the RCSPs and other stakeholders regarding the CCS–water nexus.

- Milestone and/or value-added technical reports and publications were issued that framed the CCS–water nexus, defined critical technical challenges and opportunities that are facing commercial CCS developers, and identified technology gaps that remain to be addressed for this greenhouse gas reduction strategy.

- A targeted set of published manuscripts were generated and/or compiled that focused on the CCS–water nexus.

The reference section of this appendix also serves as a bibliography, containing the primary reports and manuscripts that were generated by the WWG over the period of 2009–2017 as well as other technical publications of the RCSPs that are relevant to the CCS–water nexus.

KEY OUTCOMES

The WWG, guided by the above activities, identified the following topics of interest to the CCS industry: 1) impact of water consumption on siting of CCS operations, 2) assessment of cost/benefit of extracting formation brine, 3) treatment and beneficial reuse of extracted brine, 4) water-monitoring considerations, and 5) potential cost externalities associated with water management during deployment of CCS operations. A list of challenges and opportunities that were identified for each of these topics during the workshop are documented in Klapperich and others (2011) and a listing of key findings and observations of the WWG related to each of these topical areas is provided in the following.

Impact of Water Consumption on Siting of CCS Operations

Water supply challenges facing the energy industry have the potential to be exacerbated by the commercial deployment of CCS. Significantly increased water consumption can be expected with the addition of carbon capture processes, compression and transport of captured CO_2, and final subsurface disposition of CO_2. At the same time, additional water, in the form of extracted formation water, may be generated during storage of CO_2 if ARM is practiced as part of storage operations. Should a net increase in water demand occur, this demand will be particularly problematic in those areas of the United States where a scarcity of water already exists and may be sufficient to preclude siting of CCS operations. However, in those instances where the water balance yields a net production of water through deployment of ARM, CCS operations may provide an additional water resource for use in these same water-stressed regions.

Key outcomes of the WWG regarding these water balance issues are as follows:

- The approach to manage CCS water balance has been compared to practices deployed in the oil and gas industry for produced water management (Veil and others, 2011) and will depend upon several site-specific factors such as characteristics of the anthropogenic source of CO_2, carbon capture technology deployed, the volume of CO_2 captured and the distance it must be transported, and quality of water in the target storage formation, to name a few.

- Management of the water balance during CCS implementation is critical for CCS deployment in regions where water is in short supply. Evidence for this is provided in a study of regional water stress in Europe (Schakel and others, 2015) and a similar study conducted in the United States, which examined the effect of CCS implementation on water-stressed regions by conducting a geospatial analysis that detailed county-level balances of water supply and demand across the contiguous United States (Sathre and others, 2012). The latter study concluded that CCS can strongly affect freshwater supply and demand in specific regions, with the importance of extracted formation water increasing as the freshwater supply becomes more limited.

- From a water balance perspective, one study demonstrated that extraction of formation water from the storage reservoir could provide enough water to meet all CCS-related cooling demands of a representative NGCC power plant for 177 of 185 saline formations in the United States (Klise and others, 2013). Another study, following an examination of three locations in the United States, concluded that regionally appropriate management strategies could be developed to treat extracted formation water as a source of revenue, energy, and water (Breunig and others, 2013).

Assessment of the Cost/Benefit of Extracting Formation Brine

As part of an ARM strategy, formation water is extracted to increase the storage volume of CO_2 in a target formation and/or reduce local or regional formation pressure during CO_2 injection. This action may also be used to control CO_2 migration within a specific formation or basin. The extracted formation water will likely be saline and contain a variety of different constituents, depending upon regional geology. The quality of the extracted water will be a primary factor when considering the economic viability of beneficial use of extracted water rather than its direct injection into a deep saline formation. In some circumstances, targeted storage formations may contain water with concentrations of total dissolved solids (TDS) exceeding those of protected water status (>10,000 mg/L TDS) but yet still be sufficiently low to allow economical treatment for other recycle/reuse strategies and/or surface disposal.

The WWG highlighted the ideal circumstances for considering deployment of formation water extraction combined with treatment and beneficial use of the extracted water. These circumstances comprise coexistence of relatively low salinity formation water in a region with highly stressed or limited water resources. This observation was based on a system-level analysis that was performed to assess the benefits of extracting and treating saline water from geologic formations during deployment of CCS in the United States on a national scale (Roach and others, 2016). This study concluded that the majority of storage associated with large-scale CCS in the United States would occur at a small number of well-located sites with favorable geologic properties. Using marginal abatement cost curves, this study also showed that under such a scenario, the added costs associated with resident saline water extraction, transport, and treatment would be justified by the resulting increases in CO_2 storage efficiency that would be achieved in the geologic formation.

Treatment and Beneficial Reuse of Extracted Brine

The treatment of extracted formation water remains largely undeveloped and could potentially limit the application of water extraction as a strategy for increasing carbon storage capacity, managing pressure, managing CO_2 movement, and/or generating water as a potential resource. If these typically saline waters also contain other minor constituents (e.g., trace hydrocarbons, NORM [naturally occurring radioactivity material], etc.), additional challenges may be encountered for both their handling and treatment. The WWG gathered information on the quality of extracted formation water, potential direct and beneficial use options for this potential resource, and treatment technologies available for implementing water management strategies, with the purpose of informing the continued framing of this issue for stakeholders interested in the beneficial reuse of extracted formation water. Key outcomes of that effort are as follows:

- The quality of extracted formation water will vary from low-salinity water, typical of shallower and/or younger geological formations, to very high salinity waters where beneficial use of water is unlikely but options for recovery of geothermal heat, salts, and/or minerals may be possible (Klapperich and others, 2013). For example, the average concentration of total dissolved solids (TDS) in the formation water of Mt. Simon Sandstone, a target storage formation in the Illinois Basin, was reported to be 190,000 mg/L, with primary constituents identified as chloride (120,000 mg/L), sodium (50,000 mg/L), and calcium (19,000 mg/L) (Locke and others, 2013). The composition of other formation waters from brines of overlying formations illustrates the degree of variability that can exist in the subsurface, e.g., chloride concentrations from multiple overlying formations ranged from 5000 to 137,000 mg/L (Panno and others, 2013). This variability in the composition of formation waters has also been documented at a nationwide scale, where TDS concentrations in various formations were shown to range from 1000 to 400,000 mg/L (Wolery, 2012).

- Numerous beneficial use options for extracted formation water exist (Klapperich and others, 2014): 1) power plant cooling water; 2) gray water for industrial (e.g., pulp and paper production, cement production, textile and tanning industry) and municipal (e.g., hospitals, restaurants, schools) uses; 3) drinking water for livestock and agricultural irrigation; and 4) a water source for surface flow augmentation, control of saline water intrusion into drinking water aquifers, and generation of potable water. To take advantage of these end-use options, Klapperich and others (2014) concluded that conventional physical, chemical, and thermal treatment technologies currently exist to permit implementation of many, if not most, of various water management strategies; however, in many cases, the cost of this treatment may be significant. There are feasibility and economic analysis tools available to fully examine the costs and benefits of treating extracted formation water for beneficial use (Klise and others, 2013; Sullivan and others, 2013; Kobos and others, 2011, 2016; Roach, 2016; Advanced Resources International, 2014), although the analyses that have been performed to date are limited by the lack of economic data for large-scale, commercial water treatment facilities required to manage these waters.

Water-Monitoring Considerations

Subsurface monitoring is an important component of all CCS applications. Two primary goals of this monitoring effort are to confirm the containment of injected CO_2 in the storage reservoir and to protect any overlying USDWs. The nature and extent of these monitoring efforts is dictated by a combination of applicable local, state, and federal regulations; site-specific risk assessments; and critical stakeholder concerns. However, in most instances, monitoring efforts will include items such as the installation of dedicated groundwater-monitoring wells, monitoring of existing groundwater wells, and/or monitoring areas identified as having higher potential for leakage. Parameters of interest typically include items such as conductivity, pH, water chemistry, and salinity. Conflicts may arise when applying various water laws and regulations and addressing specific concerns of stakeholders and regulators. Of particular significance are evolving regulations that require the monitoring, verification, and accounting (MVA) of injected CO_2 for both environmental as well as business accounting purposes, e.g., the ability to qualify for tax incentives based on the amount of CO_2 stored (Federal Register, 2010).

Key observations and findings of the WWG related to the subsurface monitoring of water resources during CCS include the following:

- The stakeholder survey of the WWG indicated that there is a general belief that adequate strategies do not exist to monitor the potential impacts of CCS on the quality of water resources. Given these results, the WWG proactively addressed protection of freshwater resources by addressing monitoring in three of the four fact sheets that were produced by the WWG for stakeholder outreach (Water Working Group, 2013a, 2013b, and 2014), focusing one of them specifically on MVA plans (Water Working Group, 2013b). This MVA fact sheet 1) defined an MVA monitoring framework, 2) presented monitoring objectives, as well as a subset of candidate monitoring technologies, 3) identified water resources that are being targeted for investigation as part of the large-scale demonstration projects of the RCSPs and other projects (e.g., Weyburn–Midale enhanced oil recovery/geologic storage project), and 4) described the MVA plan requirements embodied in the Class VI rule of the U.S. Environmental Protection Agency (Federal Register, 2010).

- Defining the objectives and scope of subsurface water-monitoring activities required for CCS operations is a challenge because of the uncertain regulatory environment that continues to exist due to 1) conflicting regulatory objectives (e.g., oil and gas regulations versus clean water regulations); 2) an inability to reconcile political versus hydrogeological boundaries; 3) regulatory divisions between federal, state, and local authorities; and 4) potential increases of the maximum TDS limit (10,000 ppm) for reinjection, which has been advocated by some nongovernmental organizations (NGOs).

- To date, no direct impacts to USDWs have been detected based on all of the water monitoring that has occurred at CCS sites across the United States. At the same time, an extensive amount of research is being conducted within the RCSPs and elsewhere to define an optimal set of monitoring technologies, which not only meet the necessary technical and regulatory/risk requirements of a monitoring program, but are also cost-effective. In the meantime, the U.S. Department of Energy (DOE) is developing a best practices manual (BPM) to address monitoring at CCS sites; the latest edition of this BPM was published in 2017 (U.S. Department of Energy National Energy Technology Laboratory, 2017).

Potential Cost Externalities Associated with Water Management During Deployment of CCS Operations

Several cost externalities need to be captured to permit a proper economic assessment of the CCS–water nexus. For example, the true cost/value of water resources, which vary by region, basin, regulatory boundaries, and industry types, must be properly recognized to evaluate the potential economic benefit of implementing water management strategies that both conserve water resources and maintain their quality. As long as social and political pressures keep the true cost of water resources artificially low and do not reflect the ever-increasing environmental and anthropogenic stresses on many of the existing water systems, additional costs associated with the CCS–water nexus will likely continue to discourage ARM during application of CCS.

The WWG recognized the difficulty in performing economic assessments for addressing the CCS–water nexus and made the following observations:

- A key tool for addressing cost externalities is the use of water life cycle assessments that can evaluate and prioritize future opportunities for reducing the cost of water treatment while still achieving a net positive environmental impact. No water life cycle assessments have been performed to date for commercial CCS operations.

- The current stage of development of the CCS industry has limited the ability to conduct detailed economic analyses of the CCS–water nexus. The majority of studies to date, which have been performed by the National Energy Technology Laboratory (NETL) and other DOE national laboratories, have focused on the development of systems and/or water treatment economic models that have been based on data available in the open literature and/or from bench-scale and short-term field-scale studies performed as part of the RCSPs and other CCS-related research programs. The fact that there are currently few large-scale CCS operations in the United States, none of which has been operating for extended periods of time, has resulted in a paucity of commercial-scale operating data that are necessary to inform a robust and accurate economic assessment of the cost of water management and its impact on the overall economics of CCS.

- Current technical/economic modeling studies have been helpful in evaluating the feasibility of developing water management strategies to treat extracted formation water as a source of revenue, energy, and water (Breunig and others, 2013; Klise and others, 2013), assessing the benefits of extracting and treating saline water from geologic formations during deployment of CCS on a national scale (Kobos and others, 2011; Kobos and others, 2016; Roach and others, 2016), and evaluating treatment costs for the chemical and physical qualities of formation water that could be extracted from storage reservoirs (Sullivan and others, 2013, 2014; Harto and Veil, 2011; Advanced Resources International, Inc., 2014). Moving forward, new research should continue to be conducted to provide operating data that can be used to inform and improve these models to yield more robust economic analyses through examination of the life cycle costs and benefits of treating extracted formation water for beneficial use.

Lastly, currently there are several other ongoing relevant CCS-related water research and/or field programs beyond the efforts of the RCSPs that were identified by the WWG and which will provide valuable performance and economic data relevant to all of the above-referenced topical areas of the CCS–water nexus. These projects include 1) Framework for Developing a Water for Energy Decision Support Tool (WEDST) for the Coal Sector, which is being funded by the Crosscutting Research Division of the Strategic Center for Coal; 2) Brine Extraction Storage Test

(BEST) projects, which are being funded by the NETL; and 3) the NETL-funded projects of the Carbon Storage Assurance and Facility Enterprise (CarbonSAFE) initiative. All of these efforts will provide data from larger-scale CCS operations, permitting a more reliable analysis of the economics associated with the CCS–water nexus.

LIST OF TECHNICAL PUBLICATIONS

Provided below are lists of the primary publications of the WWG.

Technical Reports

- White paper – nexus of CCS and water: "Task 14: Regional Carbon Sequestration Partnership Water Working Group White Paper on the Nexus of Carbon Capture and Storage and Water" (Deliverable D78)
- Value-added report: "Challenges and Opportunities in the Carbon Capture and Storage and Water Nexus: Technology Gap Assessment," September 2011
- "Nexus of Water and CCS: Findings of the Water Working Group (WWG) of the Regional Carbon Sequestration Partnerships" (Deliverable D107; abstract of report submitted to the 14th International Conference on Greenhouse Gas Control Technologies (GHGT-14) was accepted as a poster presentation.)

Fact Sheets

- Fact Sheet No. 1: "Regional Carbon Sequestration Partnership Water Working Group"
- Fact Sheet No. 2: "Carbon Capture Utilization and Storage (CCUS) and Water Resource Protection"
- Fact Sheet No. 3: "Monitoring, Verification, and Accounting Plans for Protection of Water Resources During the Geologic Storage of Carbon Dioxide"
- Fact Sheet No. 4: "Long-Term Protection of Freshwater Resources Following CO_2 Storage"

Other Documents

- Updated content of the WWG Web site (Deliverable D101)
- Special Issue of the International Journal of Greenhouse Gas Control – Nexus of Water and Carbon Capture (Deliverable D106)

It should be noted that several other CCS–water nexus publications that were produced by individual members of the WWG are not listed here but can be found on the Web sites of the other partnerships.

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APPENDIX 15

TASK 15 – FURTHER CHARACTERIZATION OF THE ZAMA ACID GAS EOR, CO_2 STORAGE, AND MONITORING PROJECT

TASK 15 – FURTHER CHARACTERIZATION OF THE ZAMA ACID GAS EOR, CO_2 STORAGE, AND MONITORING PROJECT

INTRODUCTION

From October 2005 through September 2009, the Zama oil field in northwestern Alberta, Canada, was the site of acid gas (approximately 70% CO_2 and 30% H_2S) injection into pinnacle reefs for the simultaneous purposes of enhanced oil recovery (EOR), H_2S disposal, and storage of CO_2. Acid gas is removed from produced oil and gas at an on-site fluid separation facility, with the oil and gas sent to market and the acid gas redirected back to the field for utilization in EOR operations. Prior to this use, CO_2 was separated from H_2S and vented to the atmosphere while H_2S was converted to sulfur, which was stockpiled on-site. This project enabled the beneficial use of the acid gas while simultaneously eliminating the need for separating H_2S from CO_2, the conversion of H_2S into elemental sulfur, and the potential for mismanagement of sulfur in the environment. At the same time, a reduction in greenhouse gas (GHG) emissions to the atmosphere was achieved.

Monitoring in the Zama oil field (hereafter named the Zama Project) was implemented to demonstrate the containment of injected acid gas in the reservoir and subsequent geologic storage of CO_2 at an EOR site that utilized H_2S-rich acid gas as the mobilizing fluid. Primary issues that were addressed included 1) potential leakage of CO_2 and/or H_2S from pinnacle reef structures; 2) long-term fate of the injected acid gas in the subsurface; and 3) ability to document the quantity of CO_2 stored in the reservoir for purposes of monetizing the carbon credits associated with applying this GHG reduction strategy (Gao and others, 2014). While this project focused on one of the hundreds of pinnacles that exist in the Zama oil field, many of the results obtained can be applied not only to other pinnacle reefs in the Alberta Basin, but to similar structures throughout the United States (e.g., hydrocarbon reservoirs in the Niagara–Lower Salina Reef Complex in the Michigan Basin) and the rest of the world.

SITE BACKGROUND

Pinnacle reef structures of the Middle Devonian Keg River Formation are the main oil-producing reservoirs in the Zama oil field. These pinnacle reefs are encountered at an average depth of 1500 m (4900 ft). Zama pinnacle reefs are typically 16 hectares (40 acres) at their base and 120 m (400 ft) tall. A large variation in both porosity and permeability is observed for these variably dolomitized carbonate pinnacles, with a decrease towards the tops of the reef. A thick and very tight anhydrite of the Muskeg Formation surrounds and overlays these oil-productive reefs and acts as a cap rock. The Zama member sits above the Keg River Formation and is the lowermost part of the Muskeg Formation. The Muskeg Formation provides an excellent seal for injected acid gas at the F Pool, the target of the Zama Project. Log-derived effective porosity of the F-Pool ranges from 0.03% to 17%; log-derived permeability varies from a very low value (0.001 mD) to significantly large values, often exceeding 1000 mD.

Continuous acid gas injection has taken place at a depth of 4900 feet into the carbonate pinnacle reef structure since December 2006. As of May 30, 2009, approximately 33,500 tons of acid gas had been injected into the pinnacle reef, of which approximately 25,000 tons was CO_2. Oil production from the pinnacle reef over the course of the project, as of May 30, 2009, was approximately 11,600 barrels.

PROJECT ACTIVITIES

Project efforts of the Plains CO_2 Reduction (PCOR) Partnership consisted of site characterization, modeling, and monitoring, verification, and accounting (MVA) activities, while the commercial partner, Apache Canada, Ltd., managed acid gas injection and hydrocarbon recovery.

A variety of research activities comprising geological, geomechanical, geochemical, and engineering studies were conducted by the PCOR Partnership at multiple scales of investigation in an effort to fully address the primary issues of CO_2/H_2S leakage, subsurface fate of injected acid gas, and quantification of the amount of stored CO_2. The end result of these research activities provided confidence in the ability of the Zama oil field to provide long-term containment of injected acid gas and subsequent storage of CO_2.

Geological Investigation

Geological investigations were focused on the reservoir, local, and regional (sub-basinal) scales. Results of these investigations indicated that natural leakage from this system is very unlikely and that regional flow is extremely slow, i.e., on the order of thousands to tens of thousands of years for migration out of the basin to occur. The potential for leakage through existing wellbores was also evaluated and found to be very low. Geomechanical evaluations, including 3-D modeling, were completed on the injection zone and adjacent stratigraphic structure. This series of evaluations confirmed that these geologic structures are excellent candidates for CO_2 sequestration. The cap rock is considered to be extremely stable, has extremely low permeability, and is not likely to fracture when subjected to injection pressures well beyond the maximum allowed by the regulatory agency. Geochemical modeling was performed to aid in understanding the long-term fate of acid gas injected into carbonate rocks. Evaluations of the Zama system indicated that the impact of mineralization on the overall storage capacity of the system is negligible and will occur very slowly over geologic time scales.

Monitoring

Monitoring of the site was achieved primarily through fluid sampling and pressure monitoring in both the target pinnacle reef and overlying strata. A gas-phase perfluorocarbon tracer, designed to mimic injected gas, was used in an effort to identify leakage into overlying stratigraphic horizons. Pressure was also measured at the injection zone and overlying productive zones to ensure that 1) overpressurization of the target did not occur, causing undue stress on the overlying cap rock that could potentially lead to rock failure, and 2) leakage along wellbores did not occur. Certifying the integrity of the system was critical, with testing focused on the cap rock and injection zone to determine the nature of potential geochemical and geomechanical changes that may occur as a result of acid gas exposure under supercritical pressures and temperatures.

Simulation

Simulation studies were conducted to evaluate various means for maximizing incremental oil recovery (IOR) and CO_2 storage capacity at the Zama oil field. Detailed static geologic and dynamic reservoir modeling was performed to evaluate future EOR potential, validate the CO_2 storage capacity, and assess the long-term fate of the injected CO_2 in this closed system. Predictive simulations were also run to explore the possibility of gaining additional storage capacity by pressure management through water extraction from the water zone below the oil–water contact. Commercial geologic modeling software (Schlumberger's Petrel™) and a compositional simulator (CMG GEM™ by Computer Modelling Group Ltd.) were used to perform modeling work. Results clearly confirmed the viability of extracting formation water to increase CO_2 storage capacity in this closed geologic structure. More specifically, an approximately fivefold increase in CO_2 storage capacity is possible if EOR is coupled with bottom water extraction. In addition, an IOR of 22.1% over 20 years can be achieved, which is 5% more than if the EOR was continued without bottom water extraction. With over 700 pinnacle reef structures in the Zama sub-basin, a careful selection of eight to sixteen pinnacle structures could provide a total CO_2 storage capacity in excess of 10 million tonnes (Mt) over a project span ranging from 4.5 to 20 years.

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APPENDIX 16

TASK 16 – CHARACTERIZATION OF THE BASAL CAMBRIAN SYSTEM

TASK 16 – CHARACTERIZATION OF THE BASAL CAMBRIAN SYSTEM

INTRODUCTION

Task 16 of the Plain CO_2 Reduction (PCOR) Partnership Program at the Energy & Environmental Research Center (EERC) comprised a 3-year binational study involving the United States and Canada, initiated to characterize a 1.34-million-km^2 area of the Cambrian–Ordovician Saline System (COSS) across the northern Great Plains–Prairie region of North America and determine its CO_2 storage capacity. The area underlain by the COSS includes several large CO_2 sources, each of which emits more than 1 million tons of CO_2/year. Assuming that each of these sources will target the COSS for the storage of their CO_2 emissions, the primary questions addressed by this study were 1) What is the CO_2 storage capacity of the COSS? 2) How many years of current CO_2 emissions will it be capable of storing? and 3) What will be required to, and what will be the effect of, injecting 104 million tons/yr of CO_2 into the COSS? The EERC represented the United States on this project; Canada was represented by Alberta Innovates Technology Futures (AITF). Other project partners included the U.S. Department of Energy (DOE), Lawrence Berkeley National Laboratory, Princeton University, Saskatchewan Industry and Resources, Manitoba Water Stewardship, Manitoba Innovation – Energy and Mines, CanmetENERGY, Natural Resources Canada, TOTAL E&P Ltd., University of Regina Petroleum Technology Research Centre (PTRC), and the North Dakota Geological Survey.

At the time of its completion, no other study had attempted to characterize the storage resource potential of large, deep saline systems that span the U.S.–Canada international border. Stratigraphically, the COSS is the lowermost saline system in the region and is dominated by thick, clean sandstone in Alberta and grades into alternating sandstone, shale, and carbonate lithologies in west-central North Dakota. The project characterized the COSS using well log and core data from three states and three provinces and created a heterogeneous 3-D geocellular model to determine the static CO_2 storage resource and dynamic storage capacity. The complexity of the reservoir was characterized from numerous sources of data, including the online databases of North Dakota, South Dakota, and Montana, and a wealth of data provided by project partners in Canada. Multimineral petrophysical analyses were conducted to determine the system's gross lithology and key petrophysical characteristics. Information derived from these analyses was used to create a facies model that captures the heterogeneity of the COSS at this broad scale. The completed geocellular model contains information on temperature, pressure, porosity, permeability, and salinity. These variables were distilled to produce components needed to compute the CO_2 storage resource of the COSS following the E-saline formula detailed by the DOE Office of Fossil Energy Atlases III and IV (U.S. Department of Energy, 2010, 2012). The results of this study show the COSS to be a very large and viable target for long-term geologic storage of anthropogenic CO_2. Modeling and simulation results indicate that, although injectivity may be a challenge in some areas, it can be overcome through the use of multiple injection wells and with distribution of CO_2 to areas of better injectivity.

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APPENDIX 17

PCOR PARTNERSHIP PHASE III DELIVERABLES, MILESTONES, AND SELECT BIBLIOGRAPHY

PCOR PARTNERSHIP PHASE III DELIVERABLES, MILESTONES, AND SELECT BIBLIOGRAPHY

INTRODUCTION

Plains CO_2 Reduction (PCOR) Partnership Phase III milestones and deliverables and their associated tasks are provided in Table 17-1. Technology transfer was an important aspect of the PCOR Partnership Program beyond scheduled deliverables and milestones. Included in this appendix is a bibliography comprising value-added products, journal articles, conference papers, book chapters, and a thesis. The multitude of presentations given during the period 2005–2018 are not included in the bibliography.

Table 17-1. Phase III Milestones and Deliverables

Title/Description	Due Date	Actual Completion Date
Year 1 – Quarter 1 (October–December 2007)		
D37: Task 4 – Fort Nelson Test Site – Geological Characterization Experimental Design Package	12/31/07	12/28/07
D63: Task 13 – Project Management Plan	12/31/07	12/28/07
M17: Task 4 – Fort Nelson Test Site Selected	12/31/07	12/28/07
Year 1 – Quarter 2 (January–March 2008)		
D38: Task 4 – Fort Nelson Test Site – Geomechanical Experimental Design Package	1/31/08	1/31/08
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/08	1/31/08
D11: Task 2 – Outreach Plan	3/31/08	3/31/08
D27: Task 3 – Environmental Questionnaire – Fort Nelson Test Site	3/31/08	4/02/08
D30: Task 4 – Williston Basin Test Site – Geomechanical Experimental Design Package	3/31/08	3/31/08
M1: Task 1 – Three Target Areas Selected for Detailed Characterization	3/31/08	3/20/08
M18: Task 4 – Fort Nelson Test Site Geochemical Work Initiated	3/31/08	3/19/08
Year 1 – Quarter 3 (April–June 2008)		
D14: Task 2 – General Phase III Fact Sheet	4/30/08	4/30/08
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/08	4/30/08
D17: Task 2 – General Phase III Information PowerPoint Presentation	5/30/08	5/30/08
M3: Task 3 – Start Environmental Questionnaire for Williston Basin Test Site	6/30/08	6/27/08
M6: Task 4 – Williston Basin Test Site Geochemical Work Initiated	6/30/08	6/30/08
M7: Task 4 – Williston Basin Test Site Geological Characterization Data Collection Initiated	6/30/08	6/30/08
Year 1 – Quarter 4 (July–September 2008)		
D12: Task 2 – Demonstration Web Pages on the Public Site	7/31/08	7/31/08
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/08	7/31/08
D1: Task 1 – Review of Source Attributes	9/30/08	9/26/08
M2: Task 1 – Demonstration Project Reporting System (DPRS) Prototype Completed	9/30/08	9/26/08
Year 2 – Quarter 1 (October–December 2008)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/08	10/31/08
D20: Task 2 – Documentary Support to PowerPoint and Web Site	12/31/08	12/31/08
D57: Task 12 – Project Assessment Annual Report	12/31/08	12/31/08

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 2 – Quarter 2 (January–March 2009)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/09	1/30/09
M21: Task 14 – Outline of White Paper on Nexus of CO_2 CCS [carbon capture and storage] and Water, Part Subtask 14.2 – White Paper on Nexus of CCS and Water	2/28/09	2/27/09
D24: Task 2 – PCOR Partnership Region Sequestration General Poster	3/31/09	3/31/09
Year 2 – Quarter 3 (April–June 2009)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/09	4/30/09
M23: Task 14 – Monthly WWG [Water Working Group] Conference Call Held	4/30/09	4/15/09
D2: Task 1 – First Target Area Completed	5/29/09	5/29/09
M23: Task 14 – Monthly WWG Conference Call Held	5/29/09	5/29/09
D16: Task 2 – Fort Nelson Test Site Fact Sheet	5/29/09	5/29/09
M24: Task 14 – WWG Annual Meeting Held	5/31/09	5/07/09
M23: Task 14 – Monthly WWG Conference Call Held	6/30/09	6/25/09
Year 2 – Quarter 4 (July–September 2009)		
M23: Task 14 – Monthly WWG Conference Call Held	Not applicable	Not required
D19: Task 2 – Fort Nelson Test Site PowerPoint Presentation	7/31/09	7/31/09
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/09	7/31/09
M22: Task 14 – Draft White Paper – Nexus of CCS and Water Available for Comments	8/17/09	8/18/09 (DOE) 8/21/09 (WWG)
M23: Task 14 – Monthly WWG Conference Call Held	8/31/09	8/25/09
D1: Task 1 – Review of Source Attributes	9/30/09	9/25/09
D3: Task 3 – Permitting Review – One State and One Province	9/30/09	9/30/09
D9: Task 1 – Updated DSS [Decision Support System]	9/30/09	9/29/09
D47: Task 6 – Report on the Preliminary Design of Advanced Compression Technology	9/30/09	9/30/09
D77: Task 13 – Risk Management Plan Outline	9/30/09	9/18/09
M4: Task 4 – Bell Creek Test Site Selected	9/30/09	9/30/09
M5: Task 4 – Bell Creek Test Site – Data Collection Initiated	9/30/09	9/30/09
M23: Task 14 – Monthly WWG Conference Call Held	9/30/09	9/22/09

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 3 – Quarter 1 (October–December 2009)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/30/09	11/02/09
D78: Task 14 – Final White Paper on the Nexus of CCS and Water	10/30/09	10/28/09
M23: Task 14 – Monthly WWG Conference Call Held	10/31/09	10/26/09
M23: Task 14 – Monthly WWG Conference Call Held	11/30/09	11/16/09
D57: Task 12 – Project Assessment Annual Report	12/31/09	12/31/09
M23: Task 14 – Monthly WWG Conference Call Held	12/31/09	Waived by DOE
Year 3 – Quarter 2 (January–March 2010)		
D13: Task 2 – Public Site Updates	1/15/10	1/15/10
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/10	1/29/10
M23: Task 14 – Monthly WWG Conference Call Held	1/31/10	1/6/10
D79: Task 14 – Water Resource Estimation Methodology Document	2/28/10	Waived by DOE
M23: Task 14 – Monthly WWG Conference Call Held	2/28/10	2/25/10
D11: Task 2 – Outreach Plan	3/31/10	3/31/10
M23: Task 14 – Monthly WWG Conference Call Held	3/31/10	3/23/10
Year 3 – Quarter 3 (April–June 2010)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/10	4/30/10
M23: Task 14 – Monthly WWG Conference Call Held	4/30/10	4/28/10
M23: Task 14 – Monthly WWG Conference Call Held	5/31/10	5/13/10
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	6/30/10	6/30/10
D19: Task 2 – Fort Nelson Test Site PowerPoint Presentation (update)	6/30/10	6/29/10
M23: Task 14 – Monthly WWG Conference Call Held	6/30/10	6/23/10
M24: Task 14 – WWG Annual Meeting Held	6/30/10	5/13/10
Year 3 – Quarter 4 (July–September 2010)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/10	7/29/10
M23: Task 14 – Monthly WWG Conference Call Held	7/31/10	7/28/10
M23: Task 14 – Monthly WWG Conference Call Held	8/31/10	8/31/10
D1: Task 1 – Review of Source Attributes	9/30/10	9/20/10
D52: Task 9 – Fort Nelson Test Site – Site Characterization, Modeling, and Monitoring Plan	9/30/10	9/30/10
M9: Task 4 – Bell Creek Test Site Geological Model Development Initiated	9/30/10	9/30/10
M23: Task 14 – Monthly WWG Conference Call Held	9/30/10	Waived by DOE

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 4 – Quarter 1 (October–December 2010)		
D87: Task 4 – Bell Creek Test Site – Geomechanical Experimental Design Package	10/30/10	10/29/10
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/10	10/29/10
M23: Task 14 – Monthly WWG Conference Call Held	10/31/10	10/26/10
M23: Task 14 – Monthly WWG Conference Call Held	11/30/10	Waived by DOE
D57: Task 12 – Project Assessment Annual Report	12/31/10	12/23/10
M23: Task 14 – Monthly WWG Conference Call Held	12/31/10	12/13/10
Year 4 – Quarter 2 (January–March 2011)		
M8: Task 4 – Bell Creek Test Site Wellbore Leakage Data Collection Initiated	1/15/11	1/14/11
D31: Task 4 – Bell Creek Test Site – Geological Characterization Experimental Design Package	1/31/11	1/27/11
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/11	1/31/11
M23: Task 14 – Monthly WWG Conference Call Held	1/31/11	1/19/11
M28: Task 4 – Bell Creek Geological Experimental Design Package Completed	1/31/11	1/27/11
D15: Task 2 – Bell Creek Test Site Fact Sheet	2/28/11	2/28/11
M23: Task 14 – Monthly WWG Conference Call Held	2/28/11	Waived by DOE
D10: Task 1 – Demonstration Project Reporting System Update	3/31/11	3/25/11
D18: Task 2 – Bell Creek Test Site PowerPoint Presentation (update)	3/31/11	3/31/11
D26: Task 2 – Fort Nelson Test Site Poster	3/31/11	3/31/11
D28: Task 3 – Environmental Questionnaire – Bell Creek Test Site	3/31/11	3/30/11
D85: Task 6 – Report – Opportunities and Challenges Associated with CO_2 Compression and Transportation During CCS Activities	3/31/11	3/31/11
M23: Task 14 – Monthly WWG Conference Call Held	3/31/11	3/22/11
Year 4 – Quarter 3 (April–June 2011)		
M30: Task 5 – Bell Creek Test Site Baseline MVA Initiated	4/01/11	3/24/11
M23: Task 14 – Monthly WWG Conference Call Held	4/30/11	4/21/11
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/11	4/29/11
D88: Task 13 – Programmatic Risk Management Plan	4/30/11	4/29/11
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	5/31/11	5/31/11
D34: Task 4 – Bell Creek Test Site – Baseline Hydrogeological Final Report	5/31/11	5/31/11

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 4 – Quarter 3 (April–June 2011) (continued)		
M23: Task 14 – Monthly WWG Conference Call Held	5/31/11	5/5/11
D19: Task 2 – Fort Nelson Test Site PowerPoint Presentation (update)	6/30/11	6/30/11
M23: Task 14 – Monthly WWG Conference Call Held	6/30/11	6/23/11
M24: Task 14 – WWG Annual Meeting Held	6/30/11	5/5/11
Year 4 – Quarter 4 (July–September 2011)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/11	7/28/11
M23: Task 14 – Monthly WWG Conference Call Held	7/31/11	7/26/11
D29: Task 3 – Permitting Action Plan	8/31/11	8/31/11
D66: Task 9 – Bell Creek Test Site – Simulation Report	8/31/11	8/31/11
D67: Task 9 – Fort Nelson Test Site – Simulation Report	7/31/11	8/31/11
M23: Task 14 – Monthly WWG Conference Call Held	8/31/11	8/24/11
D1: Task 1 – Review of Source Attributes	9/30/11	9/21/11
D4: Task 1 – Permitting Review – Basic EPA [U.S. Environmental Protection Agency] Requirements+	9/30/11	9/30/11
D9: Task 1 – Updated DSS	9/30/11	9/23/11
D25: Task 2 – Bell Creek Test Site Poster	9/30/11	9/30/11
D50: Task 9 – Bell Creek Test Site – Site Characterization, Modeling, and Monitoring Plan	9/30/11	9/30/11
M23: Task 14 – Monthly WWG Conference Call Held	9/30/11	Waived by DOE
M31: Task 9 – Bell Creek Test Site – Site Characterization, Modeling, and Monitoring Plan Completed	9/30/11	9/30/11
M33: Task 16 – Basal Cambrian Baseline Geological Characterization Completed	9/30/11	9/29/11
Year 5 – Quarter 1 (October–December 2011)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/11	10/31/11
M23: Task 14 – Monthly WWG Conference Call Held	10/31/11	10/26/11
M23: Task 14 – Monthly WWG Conference Call Held	11/30/11	11/30/11
D57: Task 12 – Project Assessment Annual Report	12/31/11	12/30/11
M23: Task 14 – Monthly WWG Conference Call Held	12/31/11	Waived by DOE
M34: Task 16 – Basal Cambrian Static Geological Model Completed	12/31/11	12/21/11

+ Name change requested September 28, 2011, and approved October 3, 2011.

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Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 5 – Quarter 2 (January–March 2012)		
M16: Task 4 – Bell Creek Test Site – Initiation of Production and Injection Simulation	1/13/12	12/29/11
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/12	1/31/12
D65: Task 4 – Fort Nelson Test Site – Site Characterization Report	1/31/12	1/31/12
D81: Task 1 – Regional Carbon Sequestration Atlas (update)	1/31/12	1/31/12
M23: Task 14 – Monthly WWG Conference Call Held	1/31/12	1/19/12
M29: Task 4 – Fort Nelson Site Characterization Report Completed	1/31/12	1/31/12
D91: Task 16 – Report – Geological Characterization of the Basal Cambrian System in the Williston Basin	2/29/12	2/29/12
M23: Task 14 – Monthly WWG Conference Call Held	2/29/12	2/28/12
D5: Task 1 – Second Target Area Completed	3/31/12	3/30/12
D18: Task 2 – Bell Creek Test Site PowerPoint Presentation (update)	3/31/12	3/30/12
M10: Task 4 – Bell Creek Test Site Wellbore Leakage Data Collection Completed	3/31/12	3/12/12
M36: Task 13 – Annual Advisory Board Scheduled	3/31/12	3/28/12
M23: Task 14 – Monthly WWG Conference Call Held	3/31/12	3/27/12
Year 5 – Quarter 3 (April–June 2012)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/12	4/30/12
M23: Task 14 – Monthly WWG Conference Call Held	4/30/12	Waived by DOE
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	5/31/12	5/31/12
M23: Task 14 – Monthly WWG Conference Call Held	5/31/12	5/31/12
D19: Task 2 – Fort Nelson Test Site PowerPoint Presentation (update)	6/30/12	6/29/12
D41: Task 4 – Fort Nelson Test Site – Geochemical Report	6/30/12	6/29/12
D84: Task 6 – Report – A Phased Approach to Building Pipeline Network for CO_2 Transportation During CCS	6/30/12	6/29/12
M23: Task 14 – Monthly WWG Conference Call Held	6/30/12	6/28/12
M24: Task 14 – WWG Annual Meeting Held	6/30/12	5/3/12
M32: Task 4 – Fort Nelson Geochemical Report Completed	6/30/12	6/29/12

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 5 – Quarter 4 (July–September 2012)		
D13: Task 2 – Public Site Updates	7/31/12	7/31/12
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/12	7/31/12
D67: Task 9 – Fort Nelson Test Site – Simulation Report	7/31/12	7/31/12
M23: Task 14 – Monthly WWG Conference Call Held	7/31/12	7/24/12
D66: Task 9 – Bell Creek Test Site – Simulation Report	8/31/12	8/31/12
M23: Task 14 – Monthly WWG Conference Call Held	8/31/12	8/30/12
D1: Task 1 – Review of Source Attributes	9/30/12	9/28/12
D10: Task 1 – DPRS Update	9/30/12	9/28/12
M23: Task 14 – Monthly WWG Conference Call Held	9/30/12	9/27/12
Year 6 – Quarter 1 (October–December 2012)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/12	10/31/12
M23: Task 14 – Monthly WWG Conference Call Held	10/31/12	10/25/12
M23: Task 14 – Monthly WWG Conference Call Held	11/30/12	11/28/12
D57: Task 12 – Project Assessment Annual Report	12/31/12	12/28/12
M23: Task 14 – Monthly WWG Conference Call Held	12/31/12	Waived by DOE
Year 6 – Quarter 2 (January–March 2013)		
D32: Task 4 – Bell Creek Test Site – Geomechanical Final Report	1/31/13	1/31/13
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/13	1/31/13
M23: Task 14 – Monthly WWG Conference Call Held	1/31/13	1/16/13
D14: Task 2 – General Phase III Fact Sheet (update)	2/28/13	2/28/13
M23: Task 14 – Monthly WWG Conference Call Held	2/28/13	2/28/13
D85: Task 6 – Report – Opportunities and Challenges Associated with CO_2 Compression and Transportation During CCS Activities	3/31/13	Waived by DOE (journal article)
D89: Task 16 – Report – Geochemical Evaluation of the Basal Cambrian System	3/31/13	3/28/13
D99: Task 14 – Water/CCS Nexus-Related Fact Sheet	3/31/13	3/22/13
M23: Task 14 – Monthly WWG Conference Call Held	3/31/13	3/28/13
M36: Task 13 – Annual Advisory Board Meeting Scheduled	3/31/13	3/27/13

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Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 6 – Quarter 3 (April–June 2013)		
D15: Task 2 – Bell Creek Test Site Fact Sheet (update)	4/15/13	3/25/13
D16: Task 2 – Fort Nelson Test Site Fact Sheet (update)	4/30/13	Waived by DOE
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/13	4/30/13
M14: Task 4 – Bell Creek Test Site Geological Characterization Data Collection Completed	4/30/13	4/30/13
M23: Task 14 – Monthly WWG Conference Call Held	4/30/13	4/25/13
M35: Task 16 – Basal Cambrian Dynamic Capacity Estimation Completed	4/30/13	4/30/13
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	5/31/13	5/31/13
D43: Task 5 – Bell Creek Test Site – Monitoring Experimental Design Package	5/31/13	5/31/13
M23: Task 14 – Monthly WWG Conference Call Held	5/31/13	5/30/13
M27: Task 5 – Bell Creek Test Site – MVA [monitoring, verification, and accounting] Equipment Installation and Baseline MVA Activities Completed	5/31/13	5/31/13
M23: Task 14 – Monthly WWG Conference Call Held	6/30/13	6/27/13
M26: Task 9 – Bell Creek Test Site – CO_2 Injection Initiated	6/30/13	May 2013 – sent 6/25/13
M37: Task 3 – IOGCC (Interstate Oil and Gas Compact Commission) Task Force Subgroup Meeting 2 Held	5/9/13	5/29/13
M42: Task 3 – Findings and Recommendations of the Operational and Postoperational Subgroups Presented to the Carbon Geologic Storage (CGS) Task Force	6/30/13	6/20/13 – sent 6/28/13
Year 6 – Quarter 4 (July–September 2013)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/13	7/31/13
D33: Task 4 – Bell Creek Test Site – Geochemical Final Report	7/31/13	7/31/13
M12: Task 4 – Bell Creek Test Site Geochemical Work Completed	7/31/13	7/31/13
M23: Task 14 – Monthly WWG Conference Call Held	7/31/13	7/25/13
D64: Task 4 – Bell Creek Test Site – Site Characterization Report	8/31/13	8/29/13
D66: Task 9 – Bell Creek Test Site – Simulation Report	8/31/13	8/30/13
D81: Task 1 – Regional Carbon Sequestration Atlas (update)	8/31/13	5/1/13
M23: Task 14 – Monthly WWG Conference Call Held	8/31/13	Waived by DOE

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 6 – Quarter 4 (July–September 2013) (continued)		
D1: Task 1 – Review of Source Attributes	9/30/13	9/5/13
D6: Task 3 – Permitting Review – Update 1	9/30/13	9/24/13
D48: Task 7 – Bell Creek Test Site – Procurement Plan and Agreement Report	9/30/13	9/24/13
D90: Task 16 – Report – Wellbore Evaluation of the Basal Cambrian System	9/30/13	9/5/13
D94:Task 2 – Aquistore Project Fact Sheet	9/30/13	9/30/13
D95: Task 2 – Aquistore Project Poster	9/30/13	9/30/13
D98: Task 3 – Report – Findings, Recommendations, and Guidance of CGS Task Force	9/30/13	8/30/13
M23: Task 14 – Monthly WWG Conference Call Held	9/30/13	9/30/13
M38: Task 3 – IOGCC Task Force Wrap-Up Meeting Held	9/30/13	8/16/13 – sent 9/5/13
M39: Task 3 – IOGCC Task Force Editing Subgroup Meeting Held	9/30/13	6/3/13 – sent 9/5/13
M40: Task 15 – Further Characterization of the Zama Acid Gas EOR, CO_2 Storage, and Monitoring Project Completed	9/30/13	9/24/13
Year 7 – Quarter 1 (October–December 2013)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/13	10/31/13
D42: Task 5 – Bell Creek Test Site – Injection Experimental Design Package	10/31/13	10/30/13
D99: Task 14 – Water–CCS Nexus-Related Fact Sheet	10/31/13	10/31/13
M23: Task 14 – Monthly WWG Conference Call Held	10/31/13	10/31/13
M23: Task 14 – Monthly WWG Conference Call Held	11/30/13	11/21/13
M23: Task 14 – Monthly WWG Conference Call Held	12/31/13	Waived by DOE
M24: Task 14 – WWG Annual Meeting Held	12/31/13	8/19/13
M43: Task 9 – Bell Creek Test Site – First Full-Repeat Sampling of the Groundwater-Soil Gas-Monitoring Program Completed	12/31/13	11/15/13 – sent 12/13/13
Year 7 – Quarter 2 (January–March 2014)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/14	1/31/14
D57: Task 12 – Project Assessment Annual Report	1/31/14	1/31/14
M23: Task 14 – Monthly WWG Conference Call Held	1/31/14	1/28/14
M41: Task 6 – Decision to Incorporate Ramgen Compression Technology into Bell Creek Project	1/31/14	1/29/14

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 7 – Quarter 2 (January–March 2014) (continued)		
D86: Task 15 – Updated Regional Implementation Plan for Zama	2/28/14	2/28/14
M23: Task 14 – Monthly WWG Conference Call Held	2/28/14	2/27/14
D24: Task 2 – PCOR Partnership Region Sequestration General Poster (update)	3/31/14	3/27/14
D36: Task 4 – Bell Creek Test Site – Wellbore Leakage Final Report	3/31/14	3/19/14
D92: Task 16 – Report – Storage Capacity and Regional Implications for Large-Scale Storage in the Basal Cambrian System	3/31/14	3/27/14
D93: Task 1 – Geological Modeling and Simulation Report for the Aquistore Project	3/31/14	3/25/14
D96: Task 4 – Bell Creek Test Site – 3-D Seismic and Characterization Report	3/31/14	3/27/14
M23: Task 14 – Monthly WWG Conference Call Held	3/31/14	3/25/14
M36: Task 13 – Annual Advisory Board Meeting Scheduled	3/31/14	3/4/14 sent 3/25/14
M44: Task 9 – Bell Creek Test Site – First 3-D VSP [vertical seismic profile] Repeat Surveys Completed	3/31/14	3/1/14 sent 3/25/14
Year 7 – Quarter 3 (April–June 2014)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/14	4/30/14
M23: Task 14 – Monthly WWG Conference Call Held	4/30/14	4/24/14
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	5/31/14	5/30/14
D101: Task14 – WWG Web Site Content Update	5/31/14	5/30/14
M23: Task 14 – Monthly WWG Conference Call Held	5/31/14	5/21/14
D44: Task 5 – Bell Creek Test Site – Drilling and Completion Activities Report	6/30/14	5/30/14
M23: Task 14 – Monthly WWG Conference Call Held	6/30/14	6/26/14
M45: Task 9 – Bell Creek Test Site – First Full-Repeat of Pulsed Neutron Logging Campaign Completed	6/30/14	6/9/14
M46: Task 9 – Bell Creek Test Site – 1 year of Injection Completed	6/30/14	6/26/14

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Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 7 – Quarter 4 (July–September 2014)		
D13: Task 2 – Public Site Updates	7/31/14	7/29/14
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/14	7/31/14
M23: Task 14 – Monthly WWG Conference Call Held	7/31/14	7/17/14 WebEx
D66: Task 9 – Bell Creek Test Site – Simulation Report	8/31/14	8/27/14 Exec. Sum.
M23: Task 14 – Monthly WWG Conference Call Held	8/31/14	Waived by DOE
D1: Task 1 – Review of Source Attributes	9/30/14	9/24/14
D7: Task 1 – Third Target Area Completed	9/30/14	9/26/14
D93: Task 1 – Geological Modeling and Simulation Report for the Aquistore Project	9/30/14	9/30/14
D100: Task 9 – Fort Nelson Test Site – Best Practices Manual – Feasibility Study	9/30/14	9/30/14
M23: Task 14 – Monthly WWG Conference Call Held	9/30/14	9/30/14
Year 8 – Quarter 1 (October–December 2014)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/14	10/31/14
D99: Task 14 – Water/CCS Nexus-Related Fact Sheet	10/31/14	10/31/14
M23: Task 14 – Monthly WWG Conference Call Held	10/31/14	10/28/14
M48: Task 9 – Bell Creek Test Site – 1 million metric tons of CO_2 Injected	10/31/14	10/29/14
M23: Task 14 – Monthly WWG Conference Call Held	11/30/14	11/25/14
D57: Task 12 – Project Assessment Annual Report	12/31/14	12/30/14
M24: Task 14 – WWG Annual Meeting Held	12/31/14	8/11/14
Year 8 – Quarter 2 (January–March 2015)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/15	1/30/15
D32: Task 4 – Bell Creek Test Site – Geomechanical Report (Update 1)	1/31/15	1/28/15
M23: Task 14 – Monthly WWG Conference Call Held	1/31/15	1/27/15
M23: Task 14 – Monthly WWG Conference Call Held	2/28/15	2/26/15
D25: Task 2 – Bell Creek Test Site Poster (update)	3/31/15	2/5/15
M23: Task 14 – Monthly WWG Conference Call Held	3/31/15	3/25/15
M36: Task 13 – Annual Advisory Board Meeting Scheduled	3/31/15	3/31/15

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Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 8 – Quarter 3 (April–June 2015)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/15	4/29/15
M23: Task 14 – Monthly WWG Conference Call Held	4/30/15	4/28/15
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	5/31/15	6/1/15
M23: Task 14 – Monthly WWG Conference Call Held	5/30/15	5/28/15
D85: Task 6 – Report – Opportunities and Challenges Associated with CO_2 Compression and Transportation During CCUS (carbon capture, utilization, and storage) Activities (update)	5/31/15	5/29/15
M23: Task 14 – Monthly WWG Conference Call Held	6/30/15	6/23/15
M49: Task 9 – Bell Creek Test Site – 1.5 million metric tons of CO_2 Injected	6/30/15	6/30/15
Year 8 – Quarter 4 (July–September 2015)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/15	7/31/15
M23: Task 14 – Monthly WWG Conference Call Held	7/31/15	Waived by DOE
M50: Task 9 – Bell Creek Test Site – 2 years of Near-Surface Assurance Monitoring Completed	7/31/15	7/21/15
D66: Task 9 – Bell Creek Test Site – Simulation Report	8/31/15	8/27/15 Exec. Sum.
M23: Task 14 – Monthly WWG Conference Call Held	8/31/15	Waived by DOE
M51: Task 9 – Bell Creek Test Site – Initial Analysis for First Large-Scale Repeat Pulsed-Neutron Logging Campaign Post-Significant CO_2 Injection Completed	8/31/15	8/31/15
D1: Task 1 – Review of Source Attributes (update)	9/30/15	9/23/15
D8: Task 3 – Permitting Review – Update 2	9/30/15	9/30/15
D49: Task 8 – Bell Creek Test Site – Transportation and Injection Operations Report	7/31/15	9/29/15
M23: Task 14 – Monthly WWG Conference Call Held	9/30/15	9/30/15
Year 9 – Quarter 1 (October–December 2015)		
D59/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/15	10/31/15
M23: Task 14 – Monthly WWG Conference Call Held	10/31/15	10/29/15
M23: Task 14 – Monthly WWG Conference Call Held	11/30/15	Waived by DOE
D57: Task 12 – Project Annual Assessment Report	12/31/15	12/31/15
M24: Task 14 – WWG Annual Meeting Held	12/31/15	8/20/15
M53: Task 9 – Expanded Baseline and Time-Lapse 3-D Surface Seismic Survey Completed	12/31/15	12/17/15

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 9 – Quarter 2 (January–March 2016)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/16	1/31/16
M23: Task 14 – Monthly WWG Conference Call Held	1/31/16	1/27/16
M54: Task 9 – Initial Processing and Analysis of Historic InSAR Data Completed	1/31/16	1/26/16
D14: Task 2 – General Phase III Fact Sheet (update)	2/29/16	2/26/16
D93: Task 1 – Geological Modeling and Simulation Report for the Aquistore Project (Update 2)	2/29/16	2/29/16
M23: Task 14 – Monthly WWG Conference Call Held	2/29/16	Waived by DOE
D11: Task 2 – Outreach Plan (update)	3/31/16	3/28/16
D45: Task 6 – Bell Creek Test Site – Infrastructure Development Report	3/31/16	3/31/16
M23: Task 14 – Monthly WWG Conference Call Held	3/31/16	Waived by DOE
M36: Task 13 – Annual Advisory Board Meeting Scheduled	3/31/16	3/31/16
M56: Task 9 – Life Cycle Analysis for Primary and Secondary Recovery Oil Completed	3/31/16	3/31/16
M58: Task 9 – Bell Creek Test Site – Completion of 2.75 million metric tons of CO_2 Stored	3/31/16	3/22/16
Year 9 – Quarter 3 (April–June 2016)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/16	4/29/16
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	5/31/16	5/31/16
D101: Task 14 – WWG Web Site Content Update 1	5/31/16	5/31/16
M57: Task 9 – Life Cycle Analysis for EOR at the Bell Creek Field Completed	5/31/16	5/26/16
M23: Task 14 – WWG Conference Call Held	6/30/16	4/27/16
Year 9 – Quarter 4 (July–September 2016)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/16	7/29/16
D13: Task 2 – Public Site Updates	7/31/16	7/21/16
D16: Task 2 – Fort Nelson Test Site Fact Sheet (update)	8/31/16	8/29/16
D66: Task 9 – Bell Creek Test Site – Simulation Report (update)	8/31/16	8/31/16
D102: Task 13 – Best Practices Manual – Adaptive Management Approach	8/31/16	8/31/16
M59: Task 9 – Completed the PCOR Partnership Adaptive Management Approach Best Practices Manual	8/31/16	8/31/16

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 9 – Quarter 4 (July–September 2016) (continued)		
D1: Task 1 – Review of Source Attributes (update)	9/30/16	9/29/16
D8: Task 3 – Permitting Review – Update 3	9/30/16	9/29/16
D55: Task 11 – Bell Creek Test Site – Cost-Effective Long-Term Monitoring Strategies Report	9/30/16	9/30/16
M23: Task 14 – WWG Conference Call Held	9/30/16	9/28/16
Year 10 – Quarter 1 (October–December 2016)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/16	10/27/16
D21: Task 2 – Bell Creek Test Site 30-minute Documentary	10/31/16	10/31/16
D105: Task 9 – Comparison of Non-EOR [enhanced oil recovery] and EOR Life Cycle Assessments	10/31/16	10/31/16
D15: Task 2 – Bell Creek Test Site Fact Sheet (update)	11/30/16	11/30/16
M52: Task 9 – Initial Analysis of Extended Pulsed-Neutron Logging Campaign Data Completed	11/30/16	11/29/16
D57: Task 12 – Project Assessment Annual Report	12/31/16	12/30/16
D81: Task 1 – Regional Carbon Sequestration Atlas (update)	12/31/16	12/30/16
D106: Task 14 – Special Issue of IJGGC [International Journal of Greenhouse Gas Control] – Nexus of Water and Carbon Capture and Storage	12/31/16	12/29/16
M23: Task 14 – WWG Conference Call Held	12/30/16	11/16/16
M24: Task 14 – WWG Annual Meeting Held	12/31/16	8/18/16
M36: Task 13 – Annual Advisory Board Meeting Scheduled	12/31/16	12/28/16
Year 10 – Quarter 2 (January–March 2017)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/17	1/31/17
D22: Task 2 – Energy from Coal 60-minute Documentary	1/31/17	1/31/17
D76: Task 3 – Regional Regulatory Perspective	1/31/17	1/31/17
D35: Task 4 – Bell Creek Test Site – Best Practices Manual – Site Characterization	3/31/17	3/31/17
M23: Task 14 – WWG Conference Call Held	3/31/17	3/30/17
M60: Task 1 – Data Submitted to EDX [Energy Data eXchange]	3/31/17	3/7/17
M63: Task 9 – Initial Analysis of Processed InSAR Data Completed	3/31/17	3/31/17

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 10 – Quarter 3 (April–June 2017)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/17	4/27/17
D17: Task 2 – General Phase III Information PowerPoint Presentation (update)	5/31/17	5/31/17
D69: Task 9 – Best Practices Manual – Simulation Report	5/31/17	5/31/17
D85: Task 6 – Report – Opportunities and Challenges Associated with CO_2 Compression and Transportation During CCUS Activities	5/31/17	5/31/17
D101: Task 14 – WWG Web Site Content Update 1	5/31/17	5/23/17
D104: Task 9 – Analysis of Expanded Seismic Campaign	6/30/17	6/30/17
M64: Task 9 – Initial Analysis of Expanded Seismic Campaign Data Completed	6/30/17	6/27/17
M23: Task 14 – WWG Conference Call Held	6/30/17	6/28/17
M47: Task 2 – Bell Creek Test Site 30-minute Documentary Broadcast	6/30/17	6/19/17
Year 10 – Quarter 4 (July–September 2017)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/17	7/27/17
D66: Task 9 – Bell Creek Test Site – Simulation Report (Update 6)	8/31/17	8/30/17
D81: Task 1 – PCOR Partnership Atlas (update)	8/31/17	8/31/17
D103: Task 13 – Best Practices Manual – Programmatic Risk Management	8/31/17	8/29/17
D1: Task 1 – Review of Source Attributes (update)	9/30/17	9/27/17
M23: Task 14 – WWG Conference Call Held	9/30/17	8/2/17
M55: Task 9 – Investigation of Crude Oil Compositional Changes during CO_2 EOR Completed	9/30/17	9/25/17
M62: Task 14 – Research Related to Water and CCS Nexus Completed	9/30/17	9/25/17
Year 11 – Quarter 1 (October–December 2017)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/17	10/31/17
D14: Task 2 – General Phase III Fact Sheet (update)	10/31/17	10/7/17
D51: Task 9 – Best Practices Manual – Monitoring for CO_2 Storage and CO_2 EOR	10/31/17	10/31/17
D93: Task 1 – Geological Modeling and Simulation Report for the Aquistore Project (Update 3)	10/31/17	10/7/17
D15: Task 2 – Bell Creek Test Site Fact Sheet (update)	11/30/17	10/7/17

Continued . . .

Table 17-1. Phase III Milestones and Deliverables (continued)

Title/Description	Due Date	Actual Completion Date
Year 11 – Quarter 1 (October–December 2017) (continued)		
D54: Task 10 – Report – Site Closure Procedures	12/31/17	12/28/17
D57: Task 12 – Project Assessment Annual Report	12/31/17	12/29/17
M23: Task 14 – WWG Conference Call Held	12/31/17	11/9/17
M24: Task 14 – WWG Annual Meeting Held	12/31/17	8/2/17
M36: Task 13 – Annual Advisory Board Meeting Scheduled	12/31/17	12/28/17
M65: Task 13 – PCOR Partnership Annual Membership Meeting and Workshop Held	12/31/17	12/29/17
Year 11 – Quarter 2 (January–March 2018)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	1/31/18	1/31/18
D13: Task 2 – Public Site Updates	1/31/18	1/29/18
D73: Task 11 – Bell Creek Test Site –Monitoring and Modeling Fate of CO_2 Progress Report	1/31/18	1/31/18
D8: Task 3 – Permitting Review – Update 4	2/28/18	2/23/18
D107: Task 14 – Journal Article or Topical Report – Major Research Focuses for Water and CCS	2/28/18	2/28/18
M23: Task 14 – Monthly WWG Conference Call Held	3/31/18	2/6/18
M66: Task 13 – Submission of Draft Papers on Associated Storage to Special Issue of *International Journal of Greenhouse Gas Control (IJGGC)*	3/31/18	3/29/18
Year 11 – Quarter 3 (April–June 2018)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	4/30/18	4/30/18
M67: Task 13 – Annual PCOR Partnership Technical Advisory Board Meeting Held	6/30/18	4/9/18
Year 11 – Quarter 4 (July–September 2018)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	7/31/18	7/31/18
M60: Task 13 – Data Submitted to EDX	9/30/18	9/28/18
D62: Task 13 – Final Report	9/30/18	9/28/18
Year 12 – Quarter 1 (October–December 2018)		
D58/D59: Task 13 – Quarterly Progress Report/Milestone Quarterly Report	10/31/18	10/30/18
M61: Task 10 – Site Closure for Bell Creek Test Completed	12/31/18	12/28/18

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APPENDIX 18

PANEL HEARING SESSIONS – PCOR PARTNERSHIP 2018 ANNUAL MEETING

PANEL HEARING SESSIONS – PCOR PARTNERSHIP 2018 ANNUAL MEETING

The Plains CO_2 Reduction (PCOR) Partnership enjoyed the privilege of hosting the 2018 Annual Member Meeting in the Senate Office Buildings on Capitol Hill in Washington, D.C. In the historic and magnificent settings of the Kennedy Caucus Room on Day 1 and the Indian Affairs Committee Room on Day 2, hearing-style sessions allowed witnesses from the PCOR Partnership to address questions from distinguished panelists. The Honorable John Hoeven, U.S. Senator for North Dakota, made this superb location for the meeting possible and received a PCOR Partnership Pioneer Award at the start of proceedings in recognition of his efforts to promote carbon capture, utilization, and storage (CCUS) technology and policy support.

The Day 1 hearing session focused on how PCOR Partnership technical research results inform the readiness for CCUS deployment across the region; Energy & Environmental Research Center (EERC) staff described the outstanding regional potential for CCUS deployment and explained how an adaptive management approach demonstrated the viability and security of commercial-scale storage. Successful approaches to public outreach and methods to measure that success provided further topics for debate. The hearing session Day 1 interrogatory panelists are pictured and identified in Figure 18-1. The PCOR Partnership witnesses are pictured and identified in Figure 18-2.

EERC CG56620.CDR

Figure 18-1. Hearing Session Day 1: Technical Readiness for CCUS Deployment. Interrogatory panelists (left to right): Sallie Greenberg (Illinois State Geological Survey), Stefan Bachu (Innotech Alberta), Dave Nakles (EERC, secretariat), Lynn Helms (North Dakota Industrial Commission, chair), John Gale (IEA Greenhouse Gas R&D Programme), Lynn Brickett (U.S. Department of Energy), and Jim Erdle (Computer Modelling Group Ltd.).

EERC CG56621.CDR

Figure 18-2. Hearing Session Day 1 PCOR Partnership witnesses (left to right): Ed Steadman, Charles Gorecki, John Hamling, and Neil Wildgust.

Policies required to support CCUS deployment provided the theme for the Day 2 hearing session, with regulatory certainty, infrastructure requirements, and business case development all topics under discussion. In particular, the financial opportunity afforded by the 45Q tax legislation brought tempered optimism to the proceedings. Both panelists and witnesses agreed on the urgent nature of the timescale for CCUS deployment to gain traction. The hearing session Day 2 interrogatory panelists and PCOR Partnership witnesses are pictured and identified in Figure 18-3.

EERC CG56622.CDR

Figure 18-3. Hearing Session Day 2: Policy to Support CCUS Deployment. Interrogatory panelists (rear, left to right): Fred Eames (Hunton Andrews Kurth, chair), Dave Nakles (EERC, secretariat), Lynn Helms (North Dakota Industrial Commission), Stacey Dahl (Minnkota Power Cooperative, Inc.), Matt Dahan (Denbury Resources Inc.), Jason Bohrer (Lignite Energy Council), Gerry Baker (Interstate Oil and Gas Compact Commission), and Justin Ong (ClearPath Foundation). PCOR Partnership witnesses (front, left to right): John Harju, Tom Doll, and Charles Gorecki (EERC), and William Sawyer (ALLETE Clean Energy Inc.).

APPENDIX 19

PANEL DISCUSSION: CURRENT BUSINESS CASES FOR CCUS – PCOR PARTNERSHIP 2019 ANNUAL MEETING

PANEL DISCUSSION: CURRENT BUSINESS CASES FOR CCUS – PCOR PARTNERSHIP 2019 ANNUAL MEETING

The Plains CO_2 Reduction (PCOR) Partnership hosted the 2019 Annual Meeting at the Energy & Environmental Research Center (EERC) in Grand Forks, North Dakota. The Honorable Charles McConnell (Executive Director, Center for Carbon Management and Energy Sustainability, University of Houston) chaired a panel session with several prominent CEOs engaged in the energy business and examined the potential future role of carbon capture, utilization, and storage (CCUS) in their business model. Panelists are pictured and identified in Figure 19-1.

A synopsis of panel responses to a number of questions posed by the chair is as follows:

What are the primary competitions for capital in your business?

Coal, our most abundant energy resource, can ensure energy, financial, and national security; the United States should maintain coal-fired power and not abandon this resource. Most coal-fired generation plants have two basic options for managing carbon emissions: incorporate CCUS or replace with gas plants, the latter option writing off stranded assets that may still have significant attached debt and result in higher-priced electricity.

EERC CG56623.CDR

Figure 19-1. Panel from left to right: Charles McConnell (chair), Christian Kendall (Director, President, and CEO, Denbury Resources), Robert “Mac” McLennan (President and CEO, Minnkota Power Cooperative), Wade Boeshans (President and General Manager, BNI Energy), Paul Sukut (CEO and General Manager, Basin Electric Power Cooperative), and John Mingé (Senior Executive, BP America, Inc./Chair, National Petroleum Council CCUS Study).

What do you worry about most regarding the commercial deployment of CCUS?

The political landscape regarding climate change is in a state of constant flux, but CCUS projects require stable policies. Public concerns over such issues as carbon emissions and fracking reduce confidence in CCUS projects. Perceived uncertainty associated with storing carbon underground renders cost/benefit analysis of CCUS challenging. There is a real danger of premature shutdown of coal plants as part of an effort to reduce carbon emissions to zero.

Moving forward, the general public should be educated about the inability of the United States to simply cease the use of fossil fuels and replace them with sources of renewable energy while still maintaining a reliable baseload of energy for the country. Both developers and investors need to show more courage by moving forward with CCUS projects.

What is the potential for the offshore application of CCUS and the global application of CO_2 EOR?

In the offshore environment, CO_2 storage is possible but CO_2 enhanced oil recovery (EOR) is too costly. Offshore opportunities for CO_2 storage exist in the form of hydrocarbon reservoirs, but there are still several risk factors to consider with offshore development, and estimates of the cost remain uncertain.

Regulatory and permitting uncertainty represent the biggest hurdles for offshore and global applications of CCUS. In addition, there is a need to maximize the use of existing information to convince investors that CO_2 geologic storage is secure and viable.

A critical challenge facing the energy industry, given policies that emphasize renewables, is an excess capacity in this space when credits cease. No value is currently assigned to "keeping the lights on" (i.e., reliability of the energy grid); however, after renewable credits are removed, "reliable baseload" may be of greater importance. How will companies meet this challenge?

One utility noted that their energy mix comprises 60% coal and the remaining 40% from gas and renewables. However, the most serious challenge to the use of coal is cheap natural gas. It was noted that when the country was hit with the polar vortex (e.g., −30°F), coal was the most reliable energy source; however, most of the public do not understand this.

The application of CO_2 EOR may be threatened by a shortage of anthropogenic CO_2. For this reason, most projects plan to rely on a mix of sources that involve both natural and anthropogenic sources of CO_2 to protect against a potential shortage of this type.

What is the continued effect of the availability of cheap natural gas?

The supply of natural gas in the world is so large that the price of natural gas is expected to remain low. This will continue to make it difficult to use coal. If more natural gas is needed, industry will simply drill more wells. Currently, the price of liquid natural gas (LNG) in the United States is approximately $3.00 per cubic foot, with $2.00 per cubic foot attributed to liquefaction and another $1.00 per cubic foot to transportation; If sold overseas, this price increases to $7.00 per cubic foot.

However, it is critical that methane emissions are controlled at the wellhead and along pipelines since losses of 2%–3% will negate all of the greenhouse gas emission reductions associated with using natural gas in lieu of coal for the production of electricity.

Movement to a hydrogen economy, where natural gas is decarbonized before combustion, and the direct capture of CO_2 from air were also noted. The economic viability of the latter is highly questionable.

What are biggest headwinds facing the commercialization of CCUS? What makes up the business case and how is value created beyond return on investment (ROI) and an increase in shareholder value?

The volatility in oil prices is important, as $50–$60 per barrel is needed to make most CO_2 EOR projects viable. There is a need to transition to CCUS to get the future quantity of CO_2 that will be needed by this industry. The pipeline infrastructure for this transition is in place; however, to date, CO_2 EOR is not profitable using anthropogenic CO_2 from CCUS, although this may be achieved within the next 5 years.

CCUS must be profitable for projects to be deployed. There is still a need to reduce overall emissions, improve efficiency, and create new products using CO_2. The Oil and Gas Climate Initiative (OGCI) is now reviewing several innovative technology pitches for the creation of new products from CO_2.

In the United States, the CO_2 EOR value chain represents the business case for CCUS (a maximum of 250 million tons of CO_2 stored per annum). However, dedicated storage in saline aquifers, which will ultimately account for 95% of the CO_2 that is stored, will require an increase in 45Q tax credits.

Energy industry assets must be used wisely as conditions can change quickly (e.g., in one previous 18-month period, gas prices went from $0.18 to $14.00 per cubic foot). A multisourced fuel mix is required to properly meet this challenge.

A coal gasification plant in North Dakota has been capturing CO_2 and selling 60% of that CO_2 for EOR in oil fields in Saskatchewan, Canada. Since 2001, 32 million tons of CO_2 has been sold for this purpose. Alternatively, the gasification plant could have used the entire quantity of captured CO_2 for the production of urea, which would have likely provided the funds necessary to sustain the coal-fired power plant that is located nearby and does not capture CO_2.