Field-Based Activities

The full range of options required to effectively manage anthropogenic CO₂ emissions may take decades to implement. The PCOR Partnership region has significant storage resources in the context of the billions of tons of CO₂ emissions that may require mitigation. As a result, the PCOR Partnership is developing and has carried out a variety of field projects to demonstrate and optimize practical and environmentally sound geologic CO₂ storage and terrestrial sequestration in the region.
The PCOR Partnership is working to demonstrate and optimize practical and environmentally sound CO₂ storage in the region. From 2005 to 2009, the PCOR Partnership conducted four field validation projects that demonstrated the effectiveness of CO₂ storage in different settings and under varying conditions. The PCOR Partnership has worked on two commercial-scale, long-term projects to demonstrate that the CO₂ storage sites have the potential to store regional CO₂ emissions safely, permanently, and economically.

**Zama Field Validation Test**
Determined the effect of acid gas injection for the purpose of acid gas disposal, geologic storage of CO₂, and EOR.

**Lignite Field Validation Test**
Investigated the ability of unminable lignite seams to store CO₂ during ECBM production.

**Northwest McGregor Field Validation Test**
Evaluated the potential for geologic storage of CO₂ in a deep carbonate reservoir for the dual purpose of CO₂ storage and EOR at depths greater than 2000 m.

**Terrestrial Field Validation Test**
Developed the technical capacity to systematically identify, develop, and apply alternate land use management practices to the prairie pothole ecosystem (at both local and regional scales) that will result in GHG reductions and salable carbon offsets.

**Fort Nelson Feasibility Project**
Investigated the feasibility that CO₂ from a commercial natural gas-processing facility can be safely and cost-effectively stored in a deep carbonate saline formation.

**Bell Creek Demonstration**
Demonstrating that commercial EOR operations with simultaneous CO₂ storage can safely and cost-effectively store regionally significant amounts of CO₂.
The Prairie Pothole Region (PPR) is a major biogeographical region that encompasses approximately 900,000 km². This region accounts for up to 70% of wild duck production in North America and provides important breeding and migratory grounds for many types of wildlife. The prairie potholes also provide many other ecological benefits, such as reducing erosion, improving water quality, buffering floods and storms, and providing recreational opportunities. However, as cultivated agriculture became the dominant land use, there was an extensive loss of native wetlands, resulting in the loss of significant amounts of soil organic carbon.
As part of the PCOR Partnership Program, the EERC; Ducks Unlimited (DU); Ducks Unlimited Canada, Inc. (DUC); the U.S. Geological Survey (USGS) Northern Prairie Wildlife Research Center; and North Dakota State University (NDSU) demonstrated optimal practices for storing CO₂ at multiple terrestrial sites located in the PPR.

A terrestrial field validation test was initiated to develop the technical capacity to systematically identify, develop, and apply alternate land use management practices to the prairie pothole ecosystem (at both the local and regional scale) that result in net GHG reductions and marketable carbon offsets. These land use management practices also contribute to improvements in water management and soil health.

As part of this project, soil and gas samples were collected from restored grasslands, native prairie, cropland, and wetlands of various age from throughout the PPR. In addition to carbon uptake and storage measurements, CH₄ and N₂O gas fluxes were measured to estimate the net GHG flux of each management practice. These data have been instrumental in advancing terrestrial carbon credits in the marketplace.

The project also demonstrated that restoration of previously farmed wetlands results in the rapid replenishment of soil organic carbon lost to cultivation at an average rate of 0.4 tonnes per hectare per year.⁴⁹ The fact that restored prairie wetlands are important carbon sinks provides a unique and previously overlooked opportunity to store atmospheric carbon in the PCOR Partnership region.
The Zama oil field in northwestern Alberta, Canada, covers an area of about 1200 km². Oil production in the Zama Field is primarily from reservoirs in pinnacle reefs. To date, over 800 pinnacles have been discovered in the Zama subbasin, with an average size of about 0.16 km² at the base and about 120 m high.
In October 2005, the Zama oil field became the site of acid gas (approximately 70% CO₂ and 30% H₂S [hydrogen sulfide]) injection for the simultaneous purpose of EOR, H₂S disposal, and CO₂ storage. Injection took place at a depth of 1500 m into a carbonate pinnacle reef structure.

The PCOR Partnership conducted MVA activities at the site through September of 2009, while Apache Canada, Ltd., managed the injection and hydrocarbon recovery processes.

**Acid Gas Beneficial Use**

Acid gas is a by-product of oil production in the Zama Field and a subsequent fluid separation process at the on-site facilities. During the separation process, oil and gas are sent to market, while acid gas is redirected back to the field for utilization in EOR operations. Before this project, the CO₂ portion of the acid gas was vented to the atmosphere, and sulfur was separated from the H₂S and stockpiled in solid form on-site. This project enabled the simultaneous beneficial use of each of these materials to produce more oil and reduce GHG emissions.

**MVA**

The MVA portion of the Zama project addressed three primary issues at EOR sites:

1. Verification of CO₂ and H₂S storage.
2. Development of reliable predictions regarding the long-term fate of injected acid gas.
3. Generation of data sets to support the development and monetization of carbon credits associated with the geologic storage of CO₂.

The geological and geochemical investigations were conducted at local and regional (subbasinal) scales. Geological results indicate that the likelihood of natural leakage from this system is low and regional flow is extremely slow, on the order of thousands to tens of thousands of years to migrate out of the basin. Monitoring of the site was achieved primarily through fluid sampling and pressure monitoring in both the target pinnacle reef and overlying strata.

Over 65,000 tonnes of CO₂ has been utilized for EOR operations, resulting in an additional 52,000 barrels of oil production. Although this project was focused on one of the hundreds of pinnacle reefs that exist in the Zama Field, many of the results can be applied to additional pinnacles in the Alberta Basin and also to similar structures throughout the world.

This project is recognized by the international Carbon Sequestration Leadership Forum as being uniquely qualified to fill technological gaps with regard to geologic storage of CO₂.
A significant acreage of deeply buried unminable coal is present in the Williston Basin. Regional-scale evaluations indicate that lignite coal in the Williston Basin has the potential to store over 100 years of CO₂ emissions from coal-fired power plants in North Dakota.
CO₂ in an Unminable Lignite Seam

From 2005 to 2009, a field validation test was conducted in Burke County, North Dakota, to determine the fate of CO₂ injected into a representative lignite coal seam and to uncover the potential for ECBM production.

**CO₂ Injection**
Approximately 90 tons of CO₂ was injected over roughly a 2-week period into a 3–4-m-thick coal seam at a depth of 330 m. CO₂ injection was accomplished using a single injection well, which was surrounded by four monitoring wells. These monitoring wells employed various technologies to track the presence and movement of CO₂ in the lignite coal seam.

**MVA**
MVA strategies were selected based on the characteristics of the site and included a combination of many techniques. Of these techniques, reservoir saturation tool logs and time-lapse crosswell seismic tomography provided the most valuable information. These techniques demonstrated that the CO₂ did not significantly move away from the wellbore and was contained within the coal seam for the duration of the 3-month monitoring period.

**Results**
This validation test demonstrated the overall feasibility of injecting CO₂ into coal seams at the field scale. It was safely executed, suggesting that similar equipment could be deployed and comparable operations could be successfully implemented at other field sites.
Williston Basin oil fields may have over 500 Mt of CO$_2$ storage resources with potential EOR operations. Oil is produced from at least a dozen rock formations at depths ranging from less than 1000 m to greater than 4300 m. This field validation test evaluated the effectiveness of CO$_2$ for EOR and storage using huff ‘n’ puff techniques at depths greater than 2440 m into a fractured carbonate reservoir.
The PCOR Partnership, working closely with Eagle Operating, Inc. (Eagle), conducted field, laboratory, and modeling activities to determine the effects of injecting CO$_2$ into a carbonate formation in the Northwest McGregor oil field in North Dakota. The activities evaluated the potential dual purpose of CO$_2$ storage and EOR in carbonate rocks deeper than 2440 m. A technical team that included Eagle, the EERC, Praxair, and Schlumberger Carbon Services conducted a variety of activities to inject CO$_2$ into the target oil reservoir using a huff 'n' puff approach and evaluated the effect that injected CO$_2$ has on the ability of the oil reservoir to store CO$_2$ and produce incremental oil.

Huff 'n' Puff

A CO$_2$ huff 'n' puff test was conducted for a well producing oil from a formation at a depth of approximately 2450 m in the Northwest McGregor oil field. As an initial pilot-scale test, 400 tonnes of CO$_2$ was injected into a single well and allowed to “soak” for several weeks (the huff). The well was then placed back into production, and the amount of incremental petroleum fluids produced was measured (the puff).

Huff 'n' puff operations can be an effective means of evaluating the response of a reservoir to CO$_2$, both with respect to EOR and CO$_2$ storage. The approach is economically attractive because small-volume injections yield adequate results to determine the efficacy of larger-scale CO$_2$ injection.

Results

Overall, the results of the field demonstration indicate that:

- CO$_2$-based huff 'n' puff operations are a technically viable option for improved oil recovery in deep carbonate oil reservoirs.
- Deep carbonate oil reservoirs are reasonable targets for large-scale CO$_2$ storage, even those with relatively low primary permeability, such as had been reported at the Northwest McGregor Field.
In 2007, the PCOR Partnership entered into the Development Phase scheduled to be conducted until 2018. In the third phase, the goal for the PCOR Partnership and the entire RCSP Program is to validate large-scale, long-term storage across North America. Each of the RCSP large-volume demonstration test projects is designed to demonstrate that the CO₂ storage sites have the potential to store regionally significant quantities of CO₂ emissions safely, permanently, and economically. Results from these efforts will provide the foundation for CCS technology commercialization.

Through its role in the RCSP Development Phase, the PCOR Partnership has teamed with industrial partners to conduct two commercial-scale CCS demonstrations in the region. One of the large-scale tests investigated CO₂ storage in a saline formation, while the other is combining CCS and EOR demonstration in a project that began in 2013. Across the country, other RCSPs have begun or are planning commercial-scale demonstrations.

The PCOR Partnership developed a philosophy that integrates site characterization, modeling and simulation, risk assessment, and MVA strategies into an iterative process to produce meaningful results for large-scale CO₂ storage projects. Elements of any of these activities are crucial for understanding or developing the other activities. For example, new knowledge gained from site characterization reduces uncertainty in geologic reservoir properties. This reduced uncertainty can then propagate through modeling, risk assessment, and MVA efforts. Because of this process, the PCOR Partnership Program is in a strong position to refine characterization, modeling, risk assessment, or MVA efforts based on the results of any of these activities and has produced a best practices manual for an adaptive management approach.
MVA capabilities are critical to ensuring the long-term viability of CCS: satisfying both technical and regulatory requirements. MVA is applicable to both terrestrial and geologic CO$_2$ storage. Terrestrial MVA must overcome difficulties in assessing carbon storage in large ecosystems (such as forests) and in gauging carbon storage potential in various types of soils. MVA for storage uses a range of existing and evolving technologies from the oil and gas industry to provide assurance that injected CO$_2$ remains securely stored in the reservoir.

The implementation of MVA serves to:

- Protect worker health and safety.
- Ensure environmental and ecological safety.
- Verify safe and effective storage.
- Track plume migration.
- Provide early warning for out-of-zone CO$_2$ mitigation.
- Confirm model predictions.
- Provide assurance for carbon credits for transactions in a carbon-trading market.
Storage techniques for MVA generally include using existing technologies in new applications, such as atmospheric and remote sensing techniques, near-surface monitoring techniques, wellbore monitoring, deep subsurface monitoring, and accounting protocols. Some of the critical challenges related to MVA include the quantification and verification of stored CO₂, development of robust, flexible accounting protocols; and reducing the cost of near-term and long-term monitoring.
The carbonate saline reservoirs targeted for the Fort Nelson CCS Feasibility Project are rock types common in the PCOR Partnership region. These rock types contribute greatly to the CO₂ capacity resource currently estimated in regional saline formations.
The Fort Nelson project, located in northeastern British Columbia, investigated the feasibility of a CCS project to mitigate the CO₂ emissions produced by Spectra Energy Transmission’s (SET’s) Fort Nelson Gas Plant. A technical team that included SET, the EERC, and others conducted a variety of activities to 1) determine the geologic, geochemical, and geomechanical properties of the target injection formation and key sealing formations in the vicinity of the injection site; 2) model the effects that large-scale injection of CO₂ may have on those properties as well as wellbore integrity; 3) evaluate the geologic risks of this injection process on local and regional scales based on results of the modeling effort; and 4) design a site-specific, risk-based MVA approach and technology deployment matrix to ensure safe and effective long-term CO₂ storage.

The results of characterization, modeling, and risk assessment efforts conducted as part of the Fort Nelson CCS feasibility study suggest that a commercial-scale CCS project in the Fort Nelson area may be technically feasible. The activities were compared to the Canadian Standards Association (CSA) standard for geologic storage of CO₂. Despite the challenging project location of the potential injection site, cost-effective MVA that meets or surpasses CSA standards is achievable.

**Status**

The Fort Nelson project originally aimed to inject approximately 2.2 million tonnes of CO₂ annually into a deep carbonate formation for long-term geologic storage. However, because of a combination of factors, including a low-price environment for natural gas and the reduced market for natural gas in the Fort Nelson area, SET suspended the project in the spring of 2015 and has no plans to conduct further activities beyond wellsite stewardship actions. However, significant accomplishments achieved since 2008 over the life of the project included many topical reports, papers, posters, and presentations that detailed the various aspects of the Fort Nelson project, including a best practices manual for CO₂ storage in deep carbonate saline formations. The lessons learned and best practices have been applied directly to other PCOR Partnership projects discussed in this atlas such as the Bell Creek and Aquistore projects.
Because natural gas-processing plants are among the few sources of relatively pure streams of CO₂ and capture is relatively easy, they will be among the first point sources of CO₂ to be targeted for CCS and CO₂ EOR projects. The Bell Creek project uses the CO₂ produced at the Lost Cabin and Shute Creek natural gas-processing plants in Wyoming. It is one of several commercial CO₂ EOR to CO₂ geologic storage projects that use CO₂ from natural gas processing.
The PCOR Partnership is working with Denbury Onshore, LLC (Denbury) to determine the effect of large-scale injection of CO\textsubscript{2} into a deep clastic reservoir for the purpose of commercial CO\textsubscript{2} EOR with associated CO\textsubscript{2} storage at Denbury’s Bell Creek oil field.

CO\textsubscript{2} for the project is sourced from the Lost Cabin and Shute Creek gas-processing facilities of Wyoming. The CO\textsubscript{2} is transported to the field at over 2600 tonnes per day via the Greencore pipeline with a tie-in from the Anadarko pipeline. The CO\textsubscript{2} is injected into an oil-bearing sandstone reservoir in the Muddy Formation at a depth of approximately 1400 m. CO\textsubscript{2} injection occurs in a staged approach (nine planned CO\textsubscript{2} developmental phases) across the field. The reservoir has been found to be suitable for miscible flooding conditions and is likely to meet the incremental oil production target of 40–50 million barrels. As with typical EOR procedures, recovered oil, CO\textsubscript{2}, and water will be separated at the process/recycle facilities located on-site. Oil is sold, whereas the water and CO\textsubscript{2} are recycled and reinjected as part of the EOR operation.

This collaborative project is demonstrating that 1) CO\textsubscript{2} storage can be safely and permanently achieved on a commercial scale in association with an EOR operation, 2) oil-bearing sandstone formations are viable regional sinks for CO\textsubscript{2}, and 3) MVA methods can be used to effectively monitor CO\textsubscript{2} storage in association with commercial-scale CO\textsubscript{2} EOR projects.

**Highlights**

- Injection of over 4 Mt of CO\textsubscript{2} (as of June 2017) since operations began at the Bell Creek site in May 2013.
- Completion of the collection of relevant baseline MVA data to aid in evaluating site security, accounting, and location of the lateral and vertical extent of CO\textsubscript{2} in the Bell Creek oil field.
- Production of a 20-minute video intended to acquaint a technical audience with the basics of casing-conveyed permanent downhole monitoring systems, as well as the unique field installation practices these systems require.
- Creation of a half-hour broadcast documentary that presents an overview of Denbury’s commercial CO\textsubscript{2} EOR program at Bell Creek and its integration with the PCOR Partnership’s investigation of associated CO\textsubscript{2} storage.
Bell Creek – Layers of Security

To safeguard freshwater aquifers during CO₂ injection or oil production, wells are engineered to protect precious groundwater resources. Well construction is governed by state and federal regulations. Three layers of steel (casing and tubing) and two layers of durable, long-lasting cement separate the contents from the surrounding groundwater in accordance with Montana regulations. Monitoring the wells adds an extra layer of security.

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Energy & Environmental Research Center
The PCOR Partnership philosophy for conducting site characterization activities is to gain as much understanding of the subsurface and near-surface environment as possible from the available data sets and to maximize the utility of any new data sets generated. Baseline site characterization activities serve as direct inputs into the various modeling and simulation activities to better predict CO₂ migration pathways, assess technical subsurface risks, and aid in the monitoring of CO₂ migration in the subsurface. These elements of the project help evaluate expected and actual performance during commercial-scale CO₂ injection, storage, and EOR.

As part of the Bell Creek study, an EERC technical team conducted a robust characterization of the reservoir and surrounding subsurface strata of the Bell Creek oil field prior to injection from 2010 to 2013. These site characterization activities were conducted to establish baseline characteristics of the reservoir, assess the viability of the reservoir in the context of CO₂ storage, evaluate and predict reservoir and seal performance and behavior during both the injection and post-injection phases of the project, and guide monitoring efforts to track and account for CO₂ in the subsurface.
A wide variety of modeling activities have been conducted at the Bell Creek site, including multiple-sized geologic models, predictive multiphase fluid flow simulations, geomechanical modeling, and geochemical simulation. These models and simulations are used to interpret and analyze the geologic, reservoir, and fluid data and conduct predictive multiphase flow, geomechanical, and geochemical simulations to identify data gaps, identify potential risks, and guide the MVA program.

Risk management, modeling, and MVA are interrelated processes, where the results of one become the inputs of the others. This creates an iterative process to manage the risks throughout the life of the project. In the initial risk assessment, the EERC project team identified and evaluated 120 potential subsurface technical risks that were grouped into broad categories (e.g., capacity, injectivity, and retention; lateral migration; vertical migration).

Technical risks identified were determined to be adequately addressed by the current MVA program. Most risks are being monitored using more than one measurement, providing multiple lines of evidence for inferring migration of CO₂ or other fluids beyond the reservoir.

Additionally, 24 strategic risks were identified (e.g., CO₂ supply, management or policy changes) and assessed. None was found to have significant potential to negatively impact the project.

**Muddy S.S (Bell Creek Field reservoir)**
The goal of the MVA program is to provide critical data to verify site security, evaluate reservoir behavior during injection, determine the ultimate fate of injected CO$_2$, and investigate mechanisms that affect CO$_2$ storage efficiency within the EOR process, all while operating in a manner compatible with the commercial CO$_2$ EOR operation. The MVA program uses time-lapse data acquisitions as part of a surface-, shallow subsurface-, and deep subsurface-monitoring effort guided by the PCOR Partnership adaptive management approach.

A suite of technology options is available for MVA programs, each technique having distinct capabilities, limitations, and costs. Further, each storage site has unique characteristics that can dictate the effectiveness of the various techniques. For this reason, the PCOR Partnership has designed a monitoring program specific to the needs of the Bell Creek Field that monitors a variety of physical phenomena using several commercially available technologies. The specific technologies selected are also designed to operate in a complementary manner where an anomalous detection from one monitoring technique can be investigated using one or more of the remaining techniques to confirm whether an issue exists. Additionally, the PCOR Partnership is evaluating each of these monitoring technologies to understand their benefits, limitations, and challenges when deployed in conjunction with a commercial CO$_2$ EOR operation.
The oldest layers of sedimentary rock in the northern Great Plains region are dated to the Cambrian and Ordovician periods of geologic time—590 to 408 million years ago. These rock layers, consisting of sandstones, carbonates, and shales, attain thicknesses up to 305 m and reach depths of 4250 m in the center of the Williston Basin. This sequence of sedimentary rock contains very salty water (up to 10 times as salty as ocean water) and is referred to as the Cambro-Ordovician Saline System (COSS).

A 3-year binational effort between the United States and Canada was initiated to characterize a 1.34-million-km$^2$ area of the COSS across the northern Great Plains–Prairie region of North America and determine its CO2 storage resource. To date, no other studies have attempted to characterize the storage resource potential of large, deep saline systems that span the U.S.–Canada international border. Significant effort was devoted to understanding the geologic and hydrogeologic architecture of the COSS and its CO2 storage resource. Stratigraphically, the COSS is the lowestmost saline system in the region and is dissected by thick, clean sandstone in Alberta and grades into alternating sandstone, shale, and carbonate lithologies in west-central North Dakota.

The results of this study show the COSS to be a large and viable target for the long-term geologic storage of anthropogenic CO2. Modeling and simulation results indicate that although injectivity may be a challenge, it can be overcome through the use of multiple injection wells and with distribution of the CO2 in areas of better geologic properties.

The area of the basal saline system suitable for CO2 storage was determined using the following criteria: a) CO2 should be stored at a lateral distance greater than 20 km from protected groundwater resources in the formation, b) porosity should be greater than 4% to ensure storage resource and injectivity, and c) CO2 should be stored at a depth to ensure it is in a dense phase. The storage resource was estimated using thickness, porosity, and CO2 density calculated at in situ conditions and using a storage efficiency factor. Assuming no increase in CO2 emissions from the large stationary sources in the region and a capture efficiency of 90%, the P50 storage resource identified in this study will suffice to store CO2 from these sources for over 700 years.

### Range of CO2 Storage Resource Estimates for the Portion of the COSS Suitable for CO2 Storage at the P10, P50, and P90 Probability Levels

<table>
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<th>$P_{50}$</th>
<th>$P_{90}$</th>
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<td>CO2 Storage Resource</td>
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<td>Canada</td>
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<td>85 Gt</td>
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<tr>
<td>Total</td>
<td>57 Gt</td>
<td>113 Gt</td>
<td>193 Gt</td>
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</tbody>
</table>

### Major Stationary CO2 Sources in the PCOR Partnership Region

- Annual CO2 Output (tonnes):
  - 15,000–75,000
  - 75,000–250,000
  - 250,000–750,000
  - 750,000–2,500,000
  - 2,500,000–7,500,000
  - 7,500,000–15,000,000
  - 15,000,000–20,000,000

### COSS Extent

- British Columbia
- Alberta
- Saskatchewan
- Manitoba
- North Dakota
- South Dakota
- Nebraska
- Minnesota
- Iowa
- Wisconsin
- Missouri
The PCOR Partnership region in central North America has extensive fossil fuel resources and ideal geologic characteristics to support CCS deployment. As a result, a handful of CCS projects around the region are moving CCS technology forward to commercialization. In addition to the efforts of the PCOR Partnership, multiple collaborative efforts are under way with support from various government, industry, and research entities to facilitate the development and wide-scale deployment of CCS. The following list highlights a select number of these projects:

1. Great Plains Synfuels Plant, North Dakota (p. 96)
The Dakota Gasification Company has captured and transported CO₂ since 2000 at a rate of approximately 3 Mt per year via a 330-km pipeline to the Weyburn and Midale oil fields in southern Saskatchewan, Canada, for EOR purposes (p. 97). These oil fields also provided the basis for a major international research effort on storage: the IEA Greenhouse Gas R&D Programme (IEAGHG) Weyburn–Midale CO₂ Monitoring and Storage Project (p. 97).

2. Boundary Dam Carbon Capture Project, Saskatchewan (p. 98)
SaskPower completed the rebuilding of Unit 3 at this coal-fired power station and began the capture of CO₂ in October 2014, at the end of September 2016, SaskPower reported that 1.15 Mt of CO₂ had been captured. The project is designed to operate at a maximum rate of 1 Mt per year; the majority of captured CO₂ is transported by pipeline to the Weyburn oil field for EOR. Unsold CO₂ is diverted into a branch of the pipeline to the Aquistore site (p. 99) for dedicated storage.

3. Quest CCS Project, Alberta
Shell Canada commenced CO₂ capture from industrial hydrogen production (a heavy oil upgrader) in November 2014 and celebrated 1 Mt of capture within the first year of operations. All captured CO₂ is transported by a 66-km pipeline to a dedicated storage site, also operated by Shell.

4. Alberta Carbon Trunk Line Project, Alberta
Construction of a 240-km pipeline by Enhance Energy will allow captured CO₂ from industrial sources to the north of Edmonton to be used for EOR at the Clive oil field. Scheduled for operation during 2017, initial CO₂ supplied will be from an Agrium fertilizer plant (up to 0.6 Mt per year) and from the North West Sturgeon Refinery (up to 1.4 Mt per year). The pipeline will be constructed with a capacity to transport up to 14.6 Mt per year to cater to additional future capture sources and EOR or dedicated storage opportunities.
CO₂ Capture at Great Plains Synfuels Plant

The CO₂ used in the Weyburn–Midale project comes from the Dakota Gasification Company’s Great Plains Synfuels Plant, the only commercial-scale coal gasification plant in the United States that manufactures synthetic natural gas. Today, the synfuels plant exports about 7900 tonnes a day of CO₂ to Canada—about 50% of the CO₂ produced when running at full rates. As of December 31, 2014, the synfuels plant had captured more than 29 Mt of CO₂.

CO₂ is captured from the Dakota Gasification Company’s Great Plains Synfuels Plant in Beulah, North Dakota, United States, and piped 330 km into the Weyburn and Midale oil fields in Saskatchewan, Canada, for EOR. The injection location covers an area of 21,000 hectares and produces 20,000 barrels of oil a day.
The Weyburn and Midale Oil Fields and Associated IEAGHG Weyburn–Midale CO₂ Monitoring and Storage Project

Injection of CO₂ for EOR purposes began in the Weyburn oil field in 2000 and at the Midale oil field in 2005. The Weyburn Field is operated by Cenovus Energy, and by January 2016, approximately 27 Mt of CO₂ had been stored in the field—mainly sourced from Great Plains but with an additional supply of CO₂ from Boundary Dam since 2014. The Midale Field is operated by Apache Canada and as of September 2016 had stored approximately 9 Mt of CO₂ sourced exclusively from Great Plains. The sale of CO₂ from the Dakota Gasification Company to Cenovus Energy and Apache Canada also represents the first instance where large quantities of captured CO₂ have been traded across an international border.

Also beginning in 2000, the IEAGHG Weyburn CO₂ Monitoring and Storage Project used the Weyburn oil field and EOR operations as an opportunity to study large-scale injection and storage of CO₂ in the subsurface. Managed by PTRC, this first phase of research was completed and reported in 2004. A second and final phase of research conducted between 2004 and 2012, again managed by PTRC, incorporated the Midale oil field and was reported in a supplemental issue of the International Journal of Greenhouse Gas Control. The project demonstrated, over both phases of research, secure storage of injected CO₂ in the reservoir and the successful deployment of existing monitoring technologies to track the subsurface movement of CO₂. The research was used to compile best practices for storage in relation to site characterization, predictive modeling, monitoring, history matching, performance validation, well integrity, risk assessment, and community outreach.

Supplies from Great Plains to Weyburn and Midale represent the first case where CO₂ has been traded between two countries.
CO₂ Capture at Boundary Dam

The Boundary Dam Carbon Capture Project is the world’s first commercial-scale, fully integrated CCS project at a coal-fired power station, with postcombustion capture of CO₂ from the rebuilt Unit 3. The capital cost of Can$1.2 billion was supported by funding from the provincial government of Saskatchewan and the federal government of Canada. Operated by the government-owned utility SaskPower, the project is designed to capture up to 1 Mt of CO₂ per year; between the commencement of operations in October 2014 and October 2016, SaskPower reported that 1.15 Mt had been captured.⁵¹

Unit 3 provides 115 MW of power.⁶¹ In addition to reducing CO₂ emissions from Unit 3 by up to 90%, the capture process removes 100% of SO₂ emissions which are converted to sulfuric acid for industrial use.

The main destination for captured CO₂ is the Weyburn oil field (p. 97), with Cenovus Energy transporting the purchased CO₂ via a 66-km pipeline. A branch of the pipeline in close proximity to the power station feeds the Aquistore project (p. 99), which is designed to provide dedicated storage for unsold CO₂.
Aquistore\textsuperscript{62} is a dual-purpose project. From a commercial perspective, Aquistore provides a dedicated storage option for unsold CO\textsubscript{2} from Boundary Dam—in effect, providing buffer storage so as to prevent any need for SaskPower to vent CO\textsubscript{2} from capture operations. Injection operations commenced in April 2015, making Aquistore the first dedicated storage project to be operating in Canada. SaskPower reported that 100,000 tonnes of CO\textsubscript{2} had been stored at Aquistore by November 2016.\textsuperscript{63}

Injection of CO\textsubscript{2} at Aquistore is via a single vertical well into the Winnipeg and Deadwood Formations at a depth of approximately 3.4 km below ground level.\textsuperscript{64}

Monitoring of the Aquistore site is managed by PTRC, which installed the injection well plus an observation well and other monitoring infrastructure through funding by federal and provincial government agencies and private industry. In addition to providing monitoring data for the regulator in accordance with permitting of the storage site, Aquistore is run as a collaborative PTRC research project which aims to demonstrate that dedicated storage in a deep saline formation is a safe and workable solution to reduce GHG emissions.

Multiple monitoring methods are under evaluation at Aquistore, representing established and novel technologies. These include cost-effective repeat 3-D seismic surveys facilitated by a permanent array of 650 surface geophones, passive seismic monitoring, and downhole monitoring including fiber-optic cables.\textsuperscript{65}

Carbon dioxide saturation within the injection plume resulting from a simulated 50-year injection scenario (37 Mt) at the PTRC Aquistore site. The model grid is nearly square, with sides approximately 5.6 km in length.
Shell Canada Energy commenced operations at Quest,52 a fully integrated CCS project located to the northeast of Edmonton, in November 2015. The first 1 Mt of CO$_2$ had been successfully captured and stored by September 2016. Capital costs of the project were supported with grants from the provincial government of Alberta and the federal Canadian government; as part of these funding agreements, detailed reports and data on various aspects of the design, construction, and performance of Quest are publicly available.66

The capture plant, located at the Scotford Refinery, was built as a modification to an existing steam methane reformer that produces hydrogen for upgrading oil sands bitumen into synthetic crude oil. Licensed Shell amine technology is used in the capture process, which reduces CO$_2$ emissions from the upgrading operations by approximately one-third.