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PCOR Partnership
Plains CO_2 Reduction (PCOR) Partnership

Fact Sheet

Practical, Environmentally Sound CO_2 Sequestration

Fort Nelson CCS Feasibility Project

Spectra Energy Transmission's (Spectra) Fort Nelson natural gas-processing facility is the largest point source of CO_2 in British Columbia. As part of a larger effort to investigate CO_2 mitigation strategies, the Plains CO_2 Reduction (PCOR) Partnership collaborated with Spectra to investigate the technical and economic feasibility of a commercial-scale geologic storage project near the Fort Nelson Gas Plant. The 2009–2012 feasibility study was part of the Phase III activities of the PCOR Partnership Program.

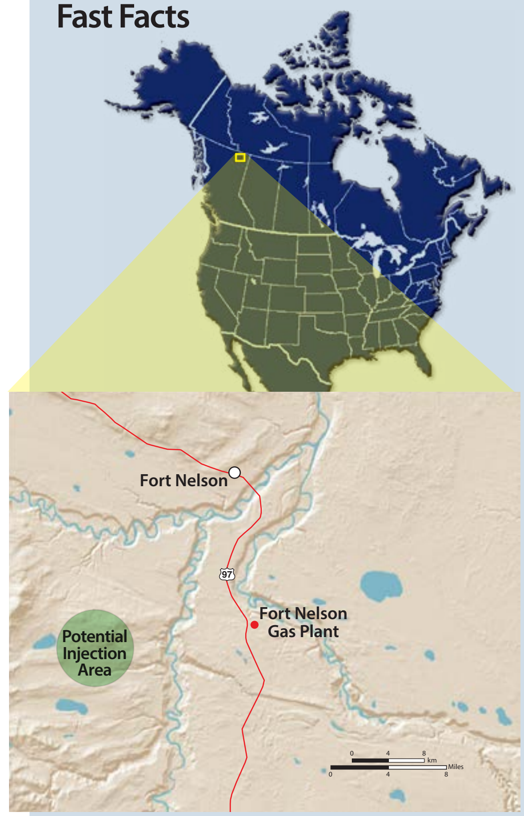
Goals and Key Results

The feasibility project was designed to 1) determine the geologic characteristics of the potential target storage rock formations (sometimes called "sinks") and key sealing rock formations in the vicinity of the injection site; 2) model the effects that large-scale injection of CO_2 may have on those rock formations and on wellbore integrity; 3) evaluate the geologic risks of the injection process at local and regional scales based on results of the modeling effort; and 4) design site-specific, risk-based monitoring, verification, and accounting (MVA) plans to ensure safe and cost-efficient, long-term CO_2 storage in the Fort Nelson study area. Results of the study indicate the following:

- The rock formations evaluated as potential CO_2 storage zones have a storage capacity estimated at 140–240 million tonnes of CO_2, sufficient to support the full anticipated emissions of the Fort Nelson Gas Plant for several decades.
- The evaluated CO_2 storage zones have the potential to support high rates of injection (>2 million tonnes of CO_2 a year), and their overlying shales have the integrity and low permeability required to ensure that the injected CO_2 will remain in the storage zones.
- Based on the current experience of the regional oil and gas community, it should be possible to successfully implement a no-frills MVA program for CO_2 using existing conventional technology to delineate the plume geometry even under the challenging terrain and climate conditions of the region.

The CO_2 source for this feasibility study was Spectra Energy's Fort Nelson Gas Plant in northeastern British Columbia (photo by Spectra Energy).

Fast Facts



Project Type: Feasibility Study

Location: Northeastern British Columbia, Canada

Injection Zone (proposed): Carbonates (limestone, dolomite), Elk Point Group (a sequence of sedimentary rock formations that occurs in western Canada)

Depth: 3000 meters (10,000 feet)

Partners: Spectra Energy Transmission, PCOR Partnership, U.S. Department of Energy, Natural Resources Canada

Although the site is an exceptional candidate for commercial-scale, long-term geologic storage of CO_2, the economics of carbon management in British Columbia did not support the financial case for moving forward with a CCS (carbon capture and storage) project at the time of the study.

Background and Approach

The site chosen for the feasibility study is a sparsely populated area of forest and swampland near Spectra's Fort Nelson gas-processing plant, the potential source of the CO_2, and the Clarke Lake gas field. Physical and climatic conditions are challenging, and most field activities are undertaken in the winter when the ground is frozen.

The project feasibility study used samples and data from an exploration hole drilled by Spectra as well as information from exploration, injection, and production reports. The data were used to develop and refine a static geologic model from which simulations predicted plume behavior and evaluated risk. The results of these activities were used to address three critical issues affecting the viability of the Fort Nelson site: 1) the capacity of the target storage formations; 2) the mobility and fate of the CO_2 at near-, intermediate-, and long-term time frames; and 3) the potential for leakage of the injected CO_2 into overlying formations, near-surface environment, or neighboring natural gas pools. The project was guided by a philosophy of integrated, iterative geologic characterization, modeling, and risk assessment intended to develop MVA strategies that are fit for purpose and cost-effective and have the greatest potential for success overall throughout the project's lifetime.

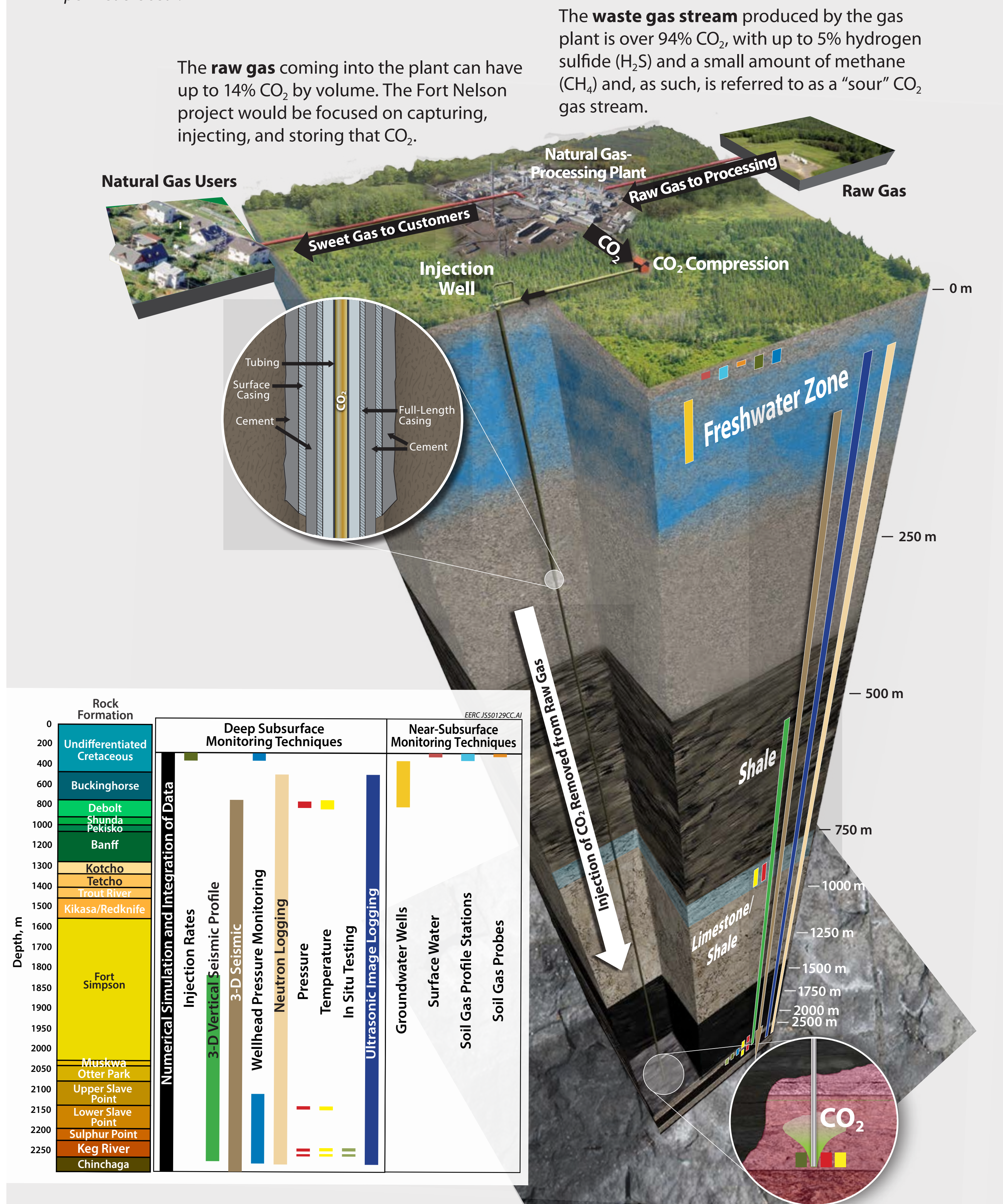
Characterization

Geologic characterization included determining the thickness, areal extent, porosity, permeability, and architectural structure of the rock formations of interest. Those included rocks of the Elk Point Group, which comprises the Slave Point, Sulphur Point, and Keg River Formations. Mechanical integrity (including an evaluation of the potential for rock fracturing during CO_2 injection operations) was also evaluated to assess injection parameters. Test results indicated that the Sulphur Point and Keg River Formations have sufficient injectivity to serve as CO_2 storage zones. The estimated injection rate into these zones is more than 2 million tonnes of CO_2 a year, with an estimated capacity of 140–240 million tonnes of CO_2. Results from the Fort Simpson and Muskwa Shales indicated that they will serve as competent vertical seals. Results from the Slave Point Formation within the Elk Point Group indicated adequate porosity and permeability to serve as a sink, but the proximity of gas reservoirs reduced its attractiveness as a sink.

A geochemical assessment was conducted because carbonate minerals (e.g., calcite and dolomite) can be reactive with the carbonic acid that is created by the dissolution of CO_2 into formation water during CO_2 injection. In addition, the products of these reactions could provide chemical signals for monitoring in overlying zones. A laboratory test program using geologic samples investigated the effects of 1) pressure, 2) temperature, 3) brine composition, and 4) injected gas stream composition. The results suggest low potential for adverse reactions involving rocks, their native fluids, and the CO_2 injection stream.

Conceptual Fort Nelson CCS Project – Injection and MVA Scheme

The concept takes CO_2 extracted from natural gas at a processing plant, compresses the CO_2 stream to a supercritical state, and transports it via pipeline approximately 15 km to an injection site. The injection target, or sink, being considered consists of brine-saturated carbonate rocks (limestone and dolomite) of a formation in the Elk Point Group. The proposed injection zone is capped by Fort Simpson and Muskwa Shale 550 m thick. These shale formations are expected to function as an impermeable seal.



Modeling and Simulation

The characterization data were used to create a static model of the potential CO_2 storage zones and seals. The model was incrementally improved as batches of characterization data became available and were incorporated. The model was then validated through a technique known as "history matching." This technique utilized decades of historical fluid injection and production data from gas production and produced water disposal wells operated in the Fort Nelson area since the 1960s. This approach ensured a reasonable match between simulated historical results and historical data before any predictive CO_2 simulations were run.[1]

After the model optimization and validation phases, predictive simulations were run to determine migration pathways for injected CO_2 and native formation brine as well as pressure propagation for both sinks and seals from the hypothetical injection wells. This information was then used as a basis for a risk assessment of the technical aspects of the subsurface components of a hypothetical CCS project at Fort Nelson.

MVA Planning

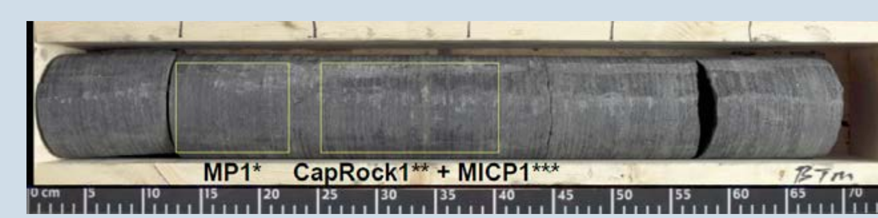
A risk-based draft MVA plan was developed for a hypothetical injection scheme. The MVA plan covers the surface, near-surface, and deep subsurface environments in the area of the gas plant and includes specific technologies, spatial locations of measurements, and baseline data necessary to address critical project risk and regulatory requirements. Through the course of running the predictive simulations and risk assessment, areas of additional characterization and potential risk were identified, leading to several additional iterations of the risk-based MVA approach. The resulting plan incorporates existing technologies to track CO_2 plume behavior without the use of seismic surveys, which would be onerous to deploy in the remote, heavily boggy terrain (muskeg). This MVA plan is viewed as a starting point for the MVA design if the project were to receive a "go" decision.

Meeting Standards

Standard CSA Z741-12, Geological Storage of Carbon Dioxide, was released in 2012 by the Canadian Standards Association (CSA). A formal assessment of the Fort Nelson feasibly plan indicated that it meets or exceeds a majority of the CSA standard specifications related to characterization, modeling, and risk assessment.[2]

Reservoir and Seal Characterization

Core samples from one of the rock formations in the Elk Point Group. These rocks display adequate porosity and permeability to support the injection and storage of CO_2 at Fort Nelson.



Core samples of shales overlying the Elk Point Group. These rocks would serve as seals for a CO_2 storage project in the Fort Nelson area.

Best Practices for Deep Carbonate Geologic Storage Projects

The experience gained during the Fort Nelson feasibility project was compiled into a best practices manual entitled *Fort Nelson Carbon Capture and Storage Feasibility Study – A Best Practices Manual for Storage in a Deep Carbonate Saline Formation.*[3] This report presents and describes the critical steps in undertaking this type of large-scale CCS project, specifically, site characterization, modeling and simulation, risk assessment, and planning for MVA. Key results are included below.

Best Practice 1 – Perform Rigorous Storage Complex Characterization

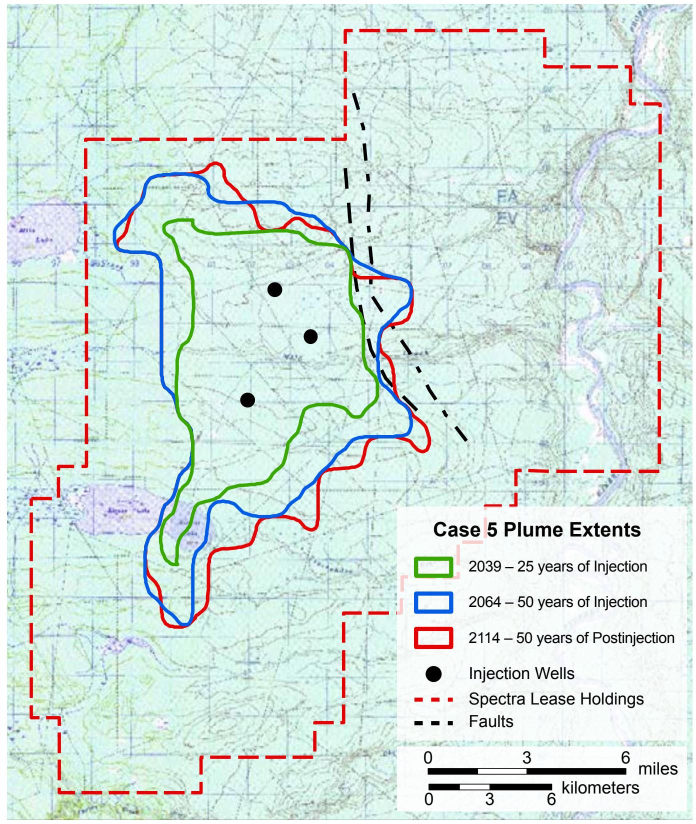
Deep carbonate saline formations may serve as effective, high-capacity locations for the large-scale geologic storage of CO_2. However, carbonate formations are inherently heterogeneous with respect to rock properties, including porosity and permeability distribution. This makes characterization of carbonates challenging and can lead to a high degree of uncertainty in the interpretation of results, especially with respect to predicting the injectivity and storage capacity of a formation. Therefore, detailed rock characterization from multiple wells and the correlation and integration of the data with other data sets (e.g., seismic surveys, hydrogeological studies) are critical to reducing that uncertainty.

Best Practice 2 – Follow Proven Standard Practices for Characterization and Modeling

The injection of CO_2 is closely analogous to conventional oil and gas production operations. Further, the mobility of CO_2 in deep carbonate saline formations is well understood from decades of CO_2 injection operations into oil fields in West Texas and the northern Great Plains for the purpose of enhanced oil recovery. Therefore, it is reasonable and advisable for site characterization and modeling exercises for CO_2 to follow the standard practices, protocols, and workflows that are commonly applied in the oil and gas industry and accepted and understood by the regulatory community.

Best Practice 3 – Practical Risk-Based MVA Is Ideal

MVA needs to meet regulatory needs, reduce technical risk, fit site-based operations, and have reasonable cost benefit. Characterization and iterative testing are critical in deriving an economical MVA strategy that meets the needs of both operators and regulators. Within this framework, the site MVA technology matrix should be site-specific, fit for purpose, and designed to address technical risks and regulatory requirements while still remaining economically sustainable over the course of the project.



Modeling and simulation activities predict CO_2 behavior through time given various injection parameters. This map shows the extent of the CO_2 plume over time predicted for one potential injection scenario (Case 5) wherein injection comprised 2.5 million tonnes of CO_2 a year for 50 years (contour interval 50 feet; map from Surveys and Mapping Branch, Department of Energy, Mines and Resources [1984]).

References

1 Gorecki, C.D., Sorensen, J.A., Klapperich, R.J., Botnen, L.S., Steadman, E.N., and Harju, J.A., 2012, A risk-based monitoring plan for the Fort Nelson feasibility project: Paper CMTC 151349 presented at the 2012 Carbon Management Technology Conference, Orlando, Florida, February 7–9, 2012, 14 p.

2 Canadian Standards Association, 2012, Standard CSA Z741-12 geological storage of carbon dioxide: Mississauga, Ontario, Canada, October 2012, 62 p.

3 Sorensen, J.A., Botnen, L.S., Smith, S.A., Liu, G., Bailey, T.P., Gorecki, C.D., Steadman, E.N., Harju, J.A., Nakles, D.V., and Azzolina, N.A., 2014, Fort Nelson carbon capture and storage feasibility study—a best practices manual for storage in a deep carbonate saline formation: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 9 Deliverable D100 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication No. 2014-EERC-11-08, Grand Forks, North Dakota, Energy & Environmental Research Center, September.

The Plains CO_2 Reduction (PCOR) Partnership is a group of public and private sector stakeholders working together to better understand the technical and economic feasibility of storing CO_2 emissions from stationary sources in the central interior of North America. The PCOR Partnership is led by the Energy & Environmental Research Center (EERC) at the University of North Dakota and is one of seven regional partnerships under the U.S. Department of Energy's National Energy Technology Laboratory Regional Carbon Sequestration Partnership Initiative. To learn more, contact:

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Visit the PCOR Partnership Web site at www.undeerc.org/PCOR. New members are welcome.

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