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Plains CO_2 Reduction (PCOR) Partnership

PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP (PHASE III) – FORT NELSON FIELD DEMONSTRATION SITE

Geomechanical Experimental Design Package (D38)

(for the period October 1, 2007, through September 30, 2009)

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Cooperative Agreement No. DE-PS26-05NT42255

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January 2008

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The PCOR Partnership is working with Spectra Energy Transmission (SET) to determine the effect of the large-scale injection of carbon dioxide (CO_2)-rich acid gas into a deep brine-saturated carbonate formation for the purpose of simultaneous acid gas disposal and sequestration of CO_2. A technical team that includes SET, the Energy & Environmental Research Center (EERC), and others will conduct a variety of activities to 1) determine the geomechanical properties of the target injection formation and key sealing formations in the vicinity of the injection site, and 2) model the effects that large-scale injection of CO_2-rich acid gas may have on those properties. SET will carry out the injection process, while the EERC will conduct CO_2 monitoring, mitigation, and verification (MMV) activities at the site. The geomechanical characterization efforts will be designed to confirm the mechanical integrity of the system, and are therefore considered to be critical elements of the MMV program. The Fort Nelson demonstration project will be a unique opportunity to develop a set of cost-effective MMV protocols for large-scale (>1 million tons per year) CO_2 sequestration in a brine-saturated formation. The effectiveness of the MMV activities will be at least partially dependent on developing a thorough understanding of the geomechanical properties of the site.

The field demonstration test conducted in the Fort Nelson area of British Columbia will evaluate the potential for geological sequestration of CO_2 as part of a gas stream that also includes high concentrations of H_2S into a brine-saturated carbonate formation. The results of the Fort Nelson activities will provide insight regarding the impact of high concentrations of H_2S (13.5%) on sink integrity (i.e., seal degradation), MMV, and successful sequestration within a carbonate reservoir. The acid gas will be obtained from the Fort Nelson gas-processing plant and injected into a brine-saturated reservoir in a Devonian-age carbonate formation at a depth of approximately 6900 to 7200 feet (2100 to 2190 meters).

The Fort Nelson Gas Plant is owned and operated by SET. The plant currently generates about 1.4 million tons of acid gas consisting of approximately 13.5% H_2S and 85.5% CO_2. This amounts to a total of about 1.2 million tons/year of CO_2 and 200,000 tons/year of H_2S. The activities at Fort Nelson will sequester an estimated 1.2 million tons of CO_2 annually.

BACKGROUND

CO_2 capture and storage (CCS) in geological media has been identified as an important means for reducing anthropogenic greenhouse gas emissions into the atmosphere (Bradshaw et. al, 2006). The PCOR Partnership's goal is to identify and test CCS opportunities in the central interior of North America. Several means for geological storage of CO_2 are available, such as depleted oil and gas reservoirs, deep brine-saturated formations (often referred to in literature as “saline aquifers”), CO_2 flood enhanced oil recovery operations, and enhanced coalbed methane recovery. Regional characterization activities conducted by the PCOR Partnership (Peck et al., 2007) and other published literature (Bachu et al., 2003) indicate that brine-saturated formations represent the largest-volume opportunities for long-term storage of CO_2 in North America. In an effort to significantly reduce CO_2 emissions from their natural gas-processing operations in northeastern British Columbia (BC) (Figure 1), SET is taking steps to initiate the first CCS project in North America to inject over 1 million tons/year of CO_2 into a saline reservoir in North America. The source and sink for this CCS project are both located in the Fort Nelson, British Columbia, area (Figure 1), and the project is, therefore, referred to as the Fort Nelson CCS Project.

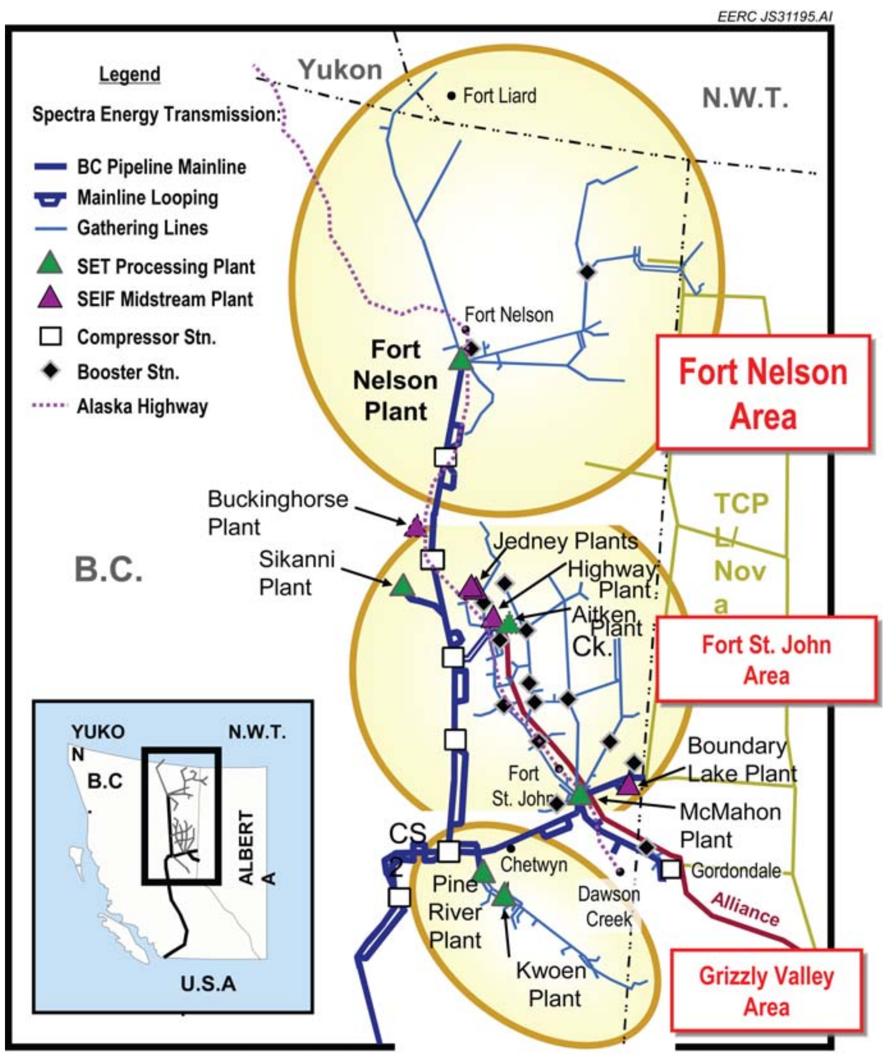

Figure 1. Location of the SET natural gas-processing plants and infrastructure in northeastern British Columbia. The PCOR Partnership Phase III demonstration project will be conducted in the Fort Nelson area.

Projects focused on CCS and associated MMV have been, and continue to be, conducted in the United States and Canada to evaluate the technical and economic components of CCS technology and provide a basis for scale-up to large demonstrations such as those being undertaken as part of the PCOR Partnership Phase III program. Developing cost-effective approaches to predict and determine the fate of the injected CO_2 is an important aspect of the emerging CCS technology. MMV activities are critical components of geological storage locations for two key reasons. First, the public must be assured that CO_2 geological storage is a safe operation. Second, markets need assurance that credits are properly assigned, traded, and accounted for. Integrated core sampling and geomechanical analysis programs can generate results that can be used to establish baseline conditions at the site in question. The baseline conditions subsequently provide a point of comparison to predict and document the effects of the large-scale acid gas injection (AGI) on the geomechanical integrity of both the target injection formation and its overlying seal. The results of laboratory-based geomechanical evaluations coupled with robust geomechanical modeling based on those results can guide the development of injection schemes that maximize the efficiency of injection and MMV plans that minimize risks of leakage.

While the Canadian and British Columbian governments are pursuing ways to encourage industry to reduce atmospheric CO_2 emissions, including CCS, the U.S. government is pursuing a vigorous program for demonstration of this technology through its Regional Carbon Sequestration Partnership Program, which entered Phase III in October 2007. This phase is planned for a duration of ten fiscal years (October 2007 to September 2016), and its main focus is characterization and monitoring of large-scale CO_2 injection into geological formations at CCS sites. The geomechanical characterization activities described in this document are scheduled to be conducted over the course of 2008 and 2009, with a final report describing the results of these activities due September 30, 2009.

The PCOR Partnership, covering nine U.S. states and four Canadian provinces, will assess the technical and economic feasibility of capturing and storing (sequestering) CO_2 emissions from stationary sources in the central interior of North America. The partnership comprises more than 70 private and public sector groups from the nine states and four provinces, among them SET, Natural Resources Canada, and the British Columbia Ministry of Energy, Mines, and Petroleum Resources (BCMEMPR). The 10-year Phase III program proposed by the PCOR Partnership aims to demonstrate the efficacy of large-scale CO_2 sequestration in two locations, including the Fort Nelson CCS project being planned by SET. The brine-saturated carbonate formations that are being considered in the Fort Nelson area as targets for large-scale injection are similar in many respects to deep carbonate rocks that are not only found in sedimentary basins of the PCOR Partnership region (Figure 2), but also around the world. It is, therefore, anticipated that the results generated at the Fort Nelson site will provide insight and knowledge that can be directly and readily applied throughout the world. Figure 3 illustrates how the proposed Fort Nelson CCS project compares to other notable CCS projects in the world with respect to annual injection volumes.

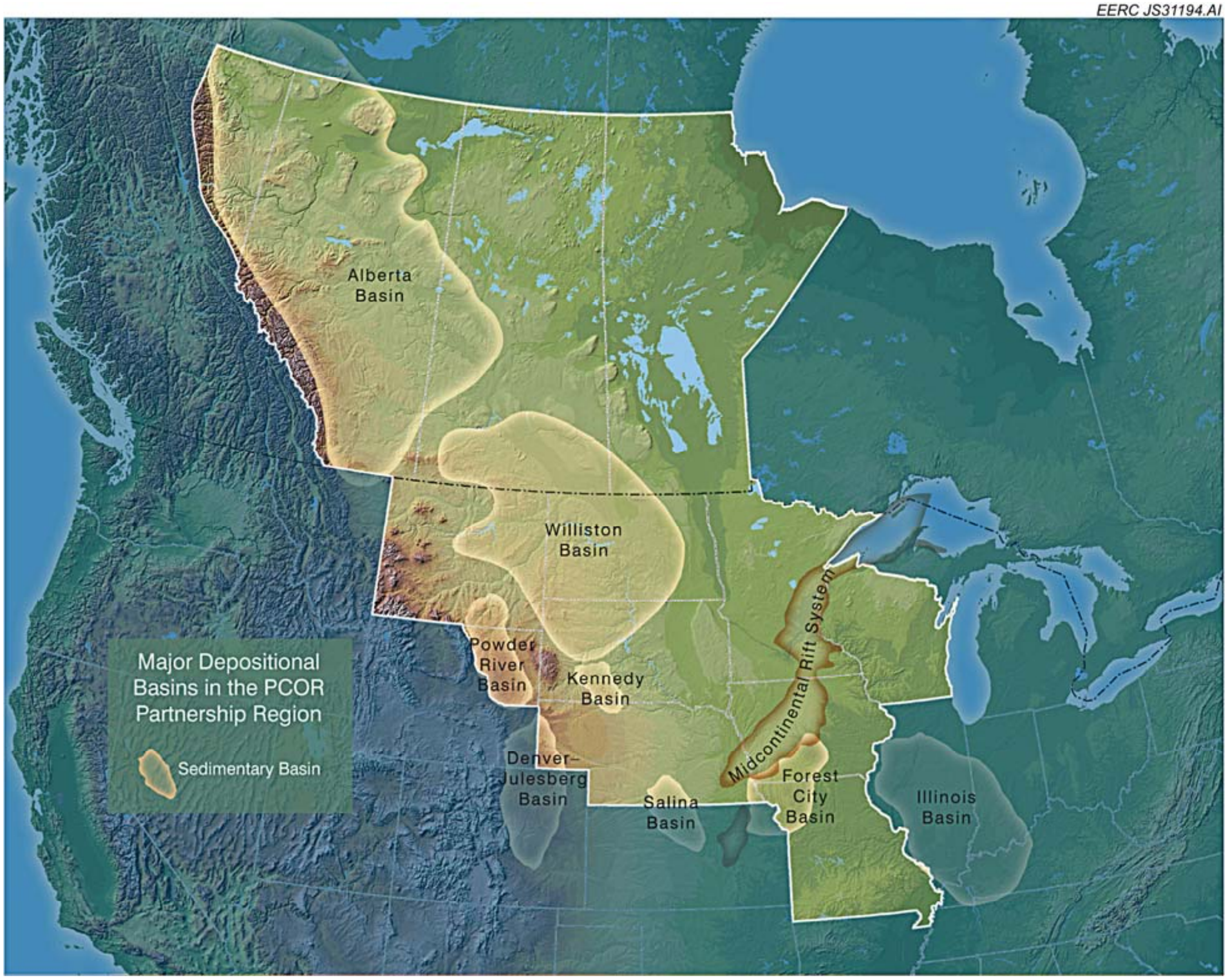

Figure 2. Sedimentary basins within the PCOR Partnership region.

FORT NELSON CCS PLAN OVERVIEW

The Fort Nelson Gas Plant (Figure 4) currently processes approximately 1.0 Bcf/day of raw natural gas from natural gas production wells in the Fort Nelson area. The processing of this raw gas stream through the plant's amine system results in the generation of an acid gas stream that is approximately 85.5% CO_2 and 13.5% H_2S. By weight, this amounts to approximately 1.2 million tons of CO_2 and 200,000 tons of H_2S per year. The Fort Nelson CCS Project proposes to drill and complete two new wells into which the entire acid gas stream will be injected into nearby Middle Devonian carbonate brine-saturated reservoirs. It is anticipated that the two injection wells will be located within 5 km of the Fort Nelson plant site. Table 1 provides the anticipated project schedule, with key events related to geomechanical work highlighted. Figure 5 depicts the conceptual plan for the Fort Nelson CCS Project.

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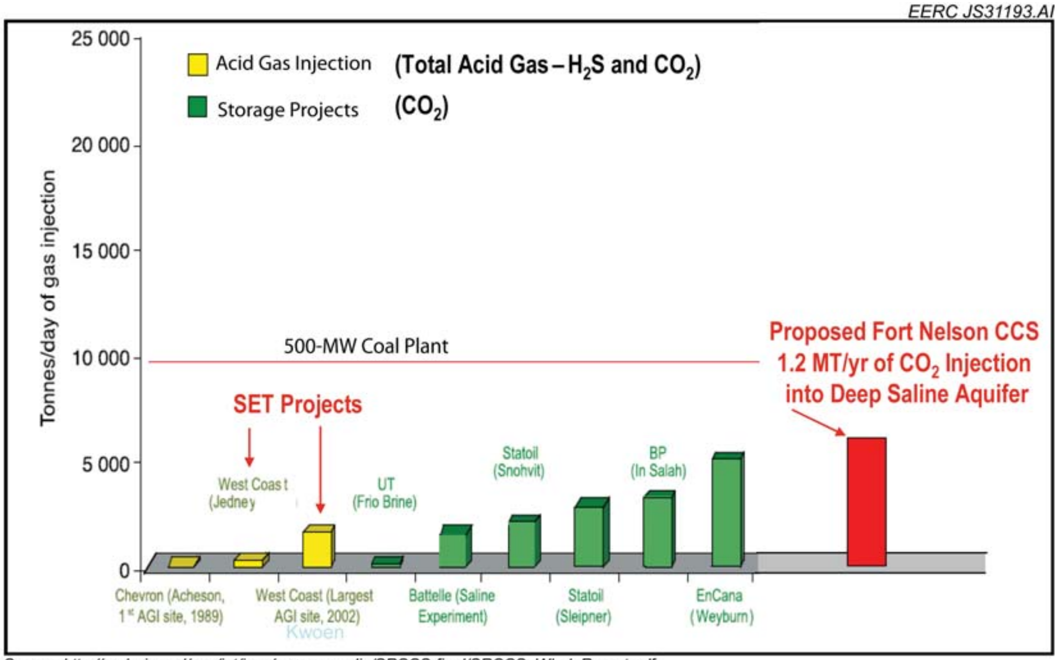

Source: http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_WholeReport.pdf

Figure 3. Relative impact of the project. Ongoing SET AGI operations in British Columbia are recognized as world-class sequestration projects by the United Nations Intergovernmental Panel on Climate Change (Metz et al., 2005).

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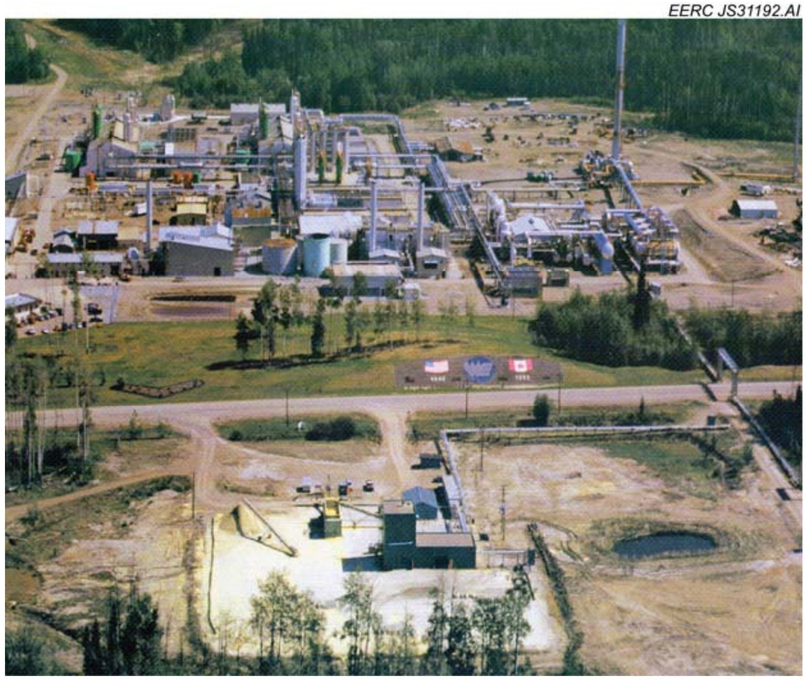

Figure 4. Fort Nelson Gas Plant, British Columbia, Canada.

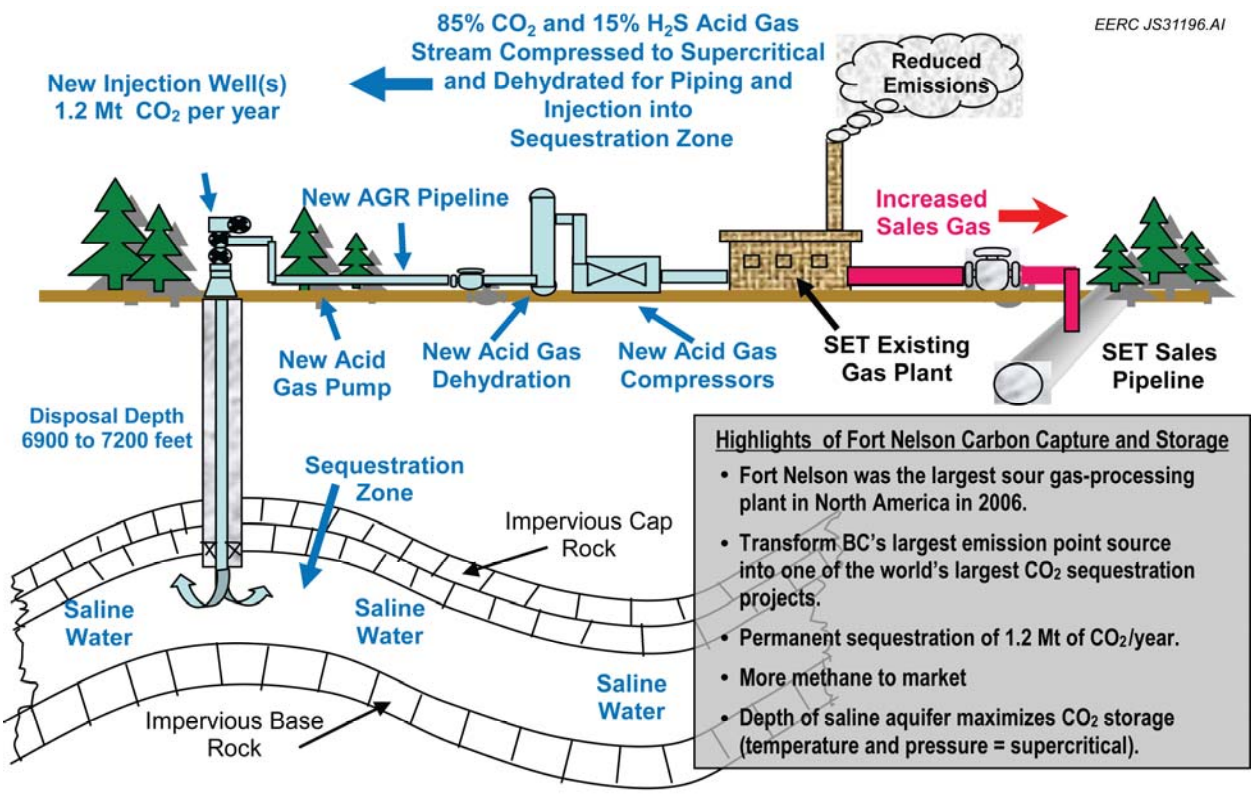

Figure 5. Fort Nelson CCS concept.

Table 1. Anticipated Fort Nelson CCS Project Schedule

2007–2008	Detailed geological, geophysical, hydrogeological, and geochemical work
	Disposal rights acquisition
	Initial reservoir model development
	Test well design + coring program w/various lab tests
	Preliminary engineering analyses and major equipment costing
	Business case for economic and technical feasibility checkpoint
2008	Drill test well with core
	Conduct in situ flow tests on both saline formations
	Initiate lab tests ***(including geomechanical tests)***
	Adjust reservoir model and engineering design
	Revisit business case checkpoint + customer negotiations
	Disposal scheme application submissions and approvals
2009	Complete lab tests ***(geomechanical results final report due 9/30/09)***
2009–2010	Project initiation and detailed design
	Drill additional wells if required + perform testing
	Material ordering
	Facility and pipe construction
Late 2010–2011	Initiate injection, and then ramp up rates with time

GEOLOGY OF THE FORT NELSON AREA

The Fort Nelson area in northeastern British Columbia (Figure 1) lies within the northwestern corner of the Alberta Basin (Figure 2). The sedimentary succession in the Fort Nelson area consists, in ascending order from the Precambrian crystalline basement to the surface, of Middle and Upper Devonian carbonates, evaporites and shales; Mississippian carbonates; and Lower Cretaceous shales overlain by Quaternary glacial drift unconsolidated sediments (Figures 6 and 7).

Exploration activities for mineral and energy resources in the area over the last 50 years have yielded a significant amount of information about the geology of northeastern British Columbia and northwestern Alberta. The carbonate platforms and reefs of the Middle Devonian formations in the northern Alberta Basin are known to contain large quantities of hydrocarbons, which suggests that the formations have adequate porosity, permeability, and trapping mechanisms to support the long-term storage of large volumes of CO_2 (Sorensen et al., 2005; Stewart and Bachu, 2000). Hydrocarbon production in the Fort Nelson area, in the form of natural gas, is primarily from reservoirs in reefs of the Middle Devonian Slave Point Formation. While the Slave Point Formation has the characteristics of a potential geological sink, the presence of economically recoverable natural gas will likely preclude it from being a sequestration target for at least a number of decades. It is anticipated that brine-saturated reservoirs within the underlying Middle Devonian Sulphur Point Formation and/or Keg River Formation will be the primary target injection zones for the Fort Nelson CCS project. The geomechanical properties of at least one of these formations will be determined. If SET decides to inject acid gas into both the Sulphur Point and Keg River Formations at the Fort Nelson site, then geomechanical properties will be determined for both.

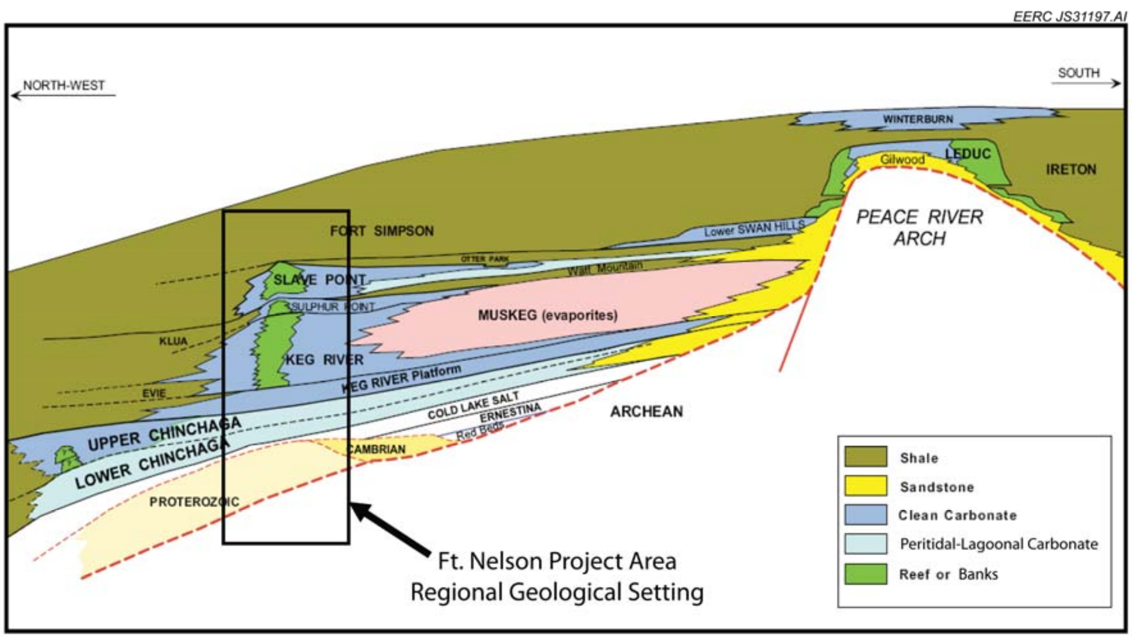

Figure 6. Stratigraphic architecture of Middle Devonian formations in the Fort Nelson area, northeastern British Columbia (BCMEMPR, 2007).

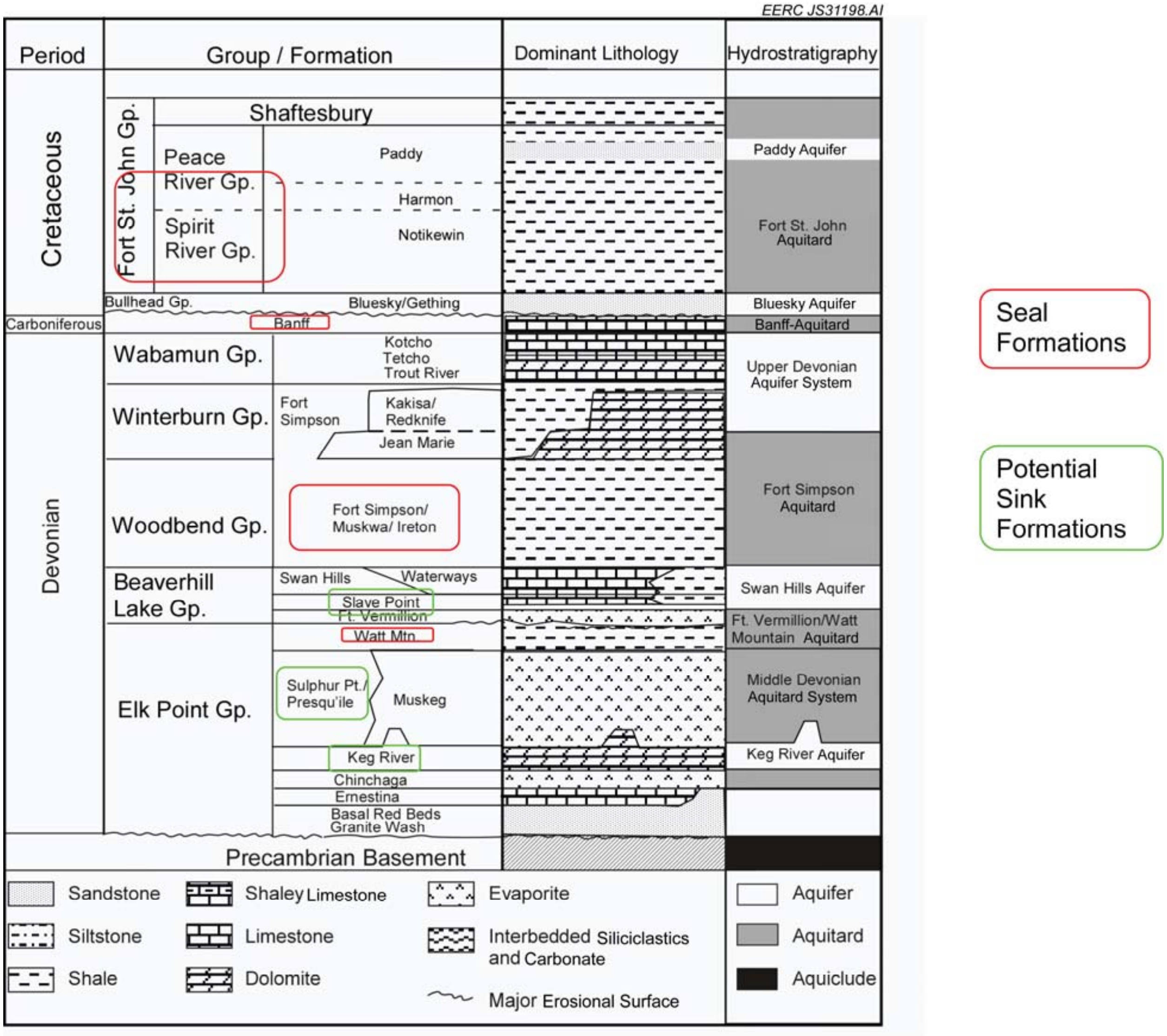

Figure 7. Stratigraphic and hydrostratigraphic delineation and nomenclature as well as general lithology for the northern part of the Alberta Basin, including northeastern British Columbia (BCMEMPR, 2007).

The Sulphur Point Formation and the Keg River Formation are both part of the Middle Devonian-age Elk Point Group (Figure 7). The Elk Point Group is composed of a succession of shallow-water carbonates, evaporites, and some siliciclastics. In the Fort Nelson area, the Sulphur Point and Keg River Formations are dominated by clean carbonate rocks (limestones and dolomites) with prominent reef and/or bank structures that have porosity and permeability characteristics that are adequate for large-scale CO_2 injection. Only a few wells have been drilled into the Sulphur Point and Keg River Formations in the vicinity of the gas-processing plant because of the lack of hydrocarbon resources in the Fort Nelson area. Therefore, data on the porosity and permeability of those rock formations in the area are sparse. However, although rock property data for the area are limited, the data that do exist suggest that porosity and permeability are likely adequate to support large-scale injection of CO_2. Currently existing data indicate that the Sulphur Point Formation ranges between 9 and 20 m in thickness in the Fort Nelson area, with porosity ranging from 3% to 25% and permeability as high as 270 md. The Keg River Formation in the area ranges between 7 and 13 m in thickness, with a reported maximum porosity range of 6% to 25% and a reported maximum permeability of 126 md. Preliminary evaluations of existing data conducted by SET indicate that the minimum permeability of either target injection formation in the Fort Nelson area is anticipated to be approximately 60 md. Table 2 summarizes the currently available data regarding key characteristics of the Sulphur Point and Keg River Formations.

Table 2. Anticipated Key Characteristics of the Likely Target Injection Formations in the Fort Nelson Area

Formation	Depth, ft	Thickness, ft	Maximum Permeability, md	Minimum Permeability, md	Porosity, %
Sulphur Point	6900	30–65	270	60	3–25
Keg River	7200	22–42	126	60	6–25

With respect to seals that will prevent upward migration of the injected acid gas, shale formations of the overlying Middle Devonian Fort Simpson Group will provide the primary seal with respect to preventing leakage to the surface. In addition, low-permeability carbonates of the upper Sulphur Point Formation and, possibly, the Watt Mountain shale (if present, see Figure 6) will prevent migration of the injected acid gas upward into the currently commercial natural gas reservoirs of the Slave Point Formation. The Mississippian-age Banff Formation, a carbonate formation that directly overlies the Devonian section in the northern Alberta Basin, is considered regionally to be an aquitard, thereby providing an additional seal between the target injection zones and the surface. Finally, the shales of the Cretaceous-age lower Fort St. John Group provide yet another layer of protection from leakage to the surface. It is anticipated that key geomechanical properties of the Watt Mountain Shale and/or the Fort Simpson Shale will be determined.

CURRENT ESTIMATED CONDITIONS

Because of the complexity and inherent heterogeneity of carbonate rock systems and the lack of wells in the immediate vicinity of the Fort Nelson plant, the current conditions of the anticipated target injection formations are not known. SET plans on drilling an exploratory well in 2008 to determine the reservoir pressure and temperature of the potential injection zones. The exploratory well program will also collect data to more precisely determine such key reservoir parameters as porosity, permeability, injectivity, and formation fluid chemistry. The SET exploratory well program at Fort Nelson is described in greater detail in the Work Plan section of this document.

WORK PLAN

SET plans on drilling one exploratory well in 2008. Plans for these drilling activities include the collection of core and cuttings from the key sink and seal formations. It is anticipated that the laboratory-based geomechanical work will be conducted using core from the exploration well. If core from the exploration well is not available, then efforts will be made to obtain core samples of the same key formations from other previous drilling activities in the area for use in the geomechanical evaluations. The activities, tasks, and deliverables described herein are derived from the PCOR Phase III continuation application Statement of Project Objectives dated September 5, 2007, and information provided by SET in October 2007. The overall purpose of these activities, from the perspective of the PCOR Partnership, is to create a best practices manual that outlines a set of guidelines for MMV operations at a location that is annually injecting over 1 million tons of CO_2 with high concentrations of H_2S into a brine-saturated carbonate formation for long-term sequestration.

The goal of geomechanical characterization program is to establish the geomechanical properties of the key sink and seal formations and the stress regime in the area to assess the mechanical integrity of the system and potential for rock fracturing. An in-depth review of the stress regime and structural features in the area of the reservoir will be conducted to identify structures such as faults or fractures. This information will help to elucidate the geological history of the reservoir and identify possible natural leakage paths like faults. It is anticipated that project activities will include a variety of laboratory- and field-based investigations. Laboratory-based activities will include compression tests to determine rock strength, static and dynamic elastic properties, compressibility, and stress-dependent permeability. Field-based activities may include in situ stress orientation and magnitude analysis, including log-based analysis of rock mechanical properties. The results generated by the laboratory and field investigations will provide the basis for geomechanical modeling.

EXISTING DATA RECONNAISSANCE, ACQUISITION, AND INTEGRATION

A wide variety of previously generated data will be collected during Year 1 of the Fort Nelson CCS Project. SET will provide the PCOR Partnership with many of the data sets upon which baseline characteristics will be established. The following data sets will be examined for information regarding local and regional stress regimes and geomechanical properties:

- Well/reservoir information of the pertinent formations.
- Data on drilling, completion, and stimulation/workover of key wells in the area.
- Digital production/injection history of key wells.
- Geological and geophysical information on the key formations in the Fort Nelson area, including formation isopach and depth maps, interpreted seismic data, hydrogeological characteristics, the presence and orientation of fractures and/or faults, and other data

that may provide insight to the geomechanical properties and integrity of the key sink and seal formations.

- Reservoir engineering data on injection zone characterization and AGI/monitoring schemes.

The existing data sets provided by SET will be integrated into the PCOR Partnership Web-based Decision Support System (DSS, ©2007 EERC Foundation). Specifically, a portion of the DSS (designated "The Fort Nelson Zone") will be devoted to storing and maintaining all data collected and generated over the course of the Fort Nelson CCS project. The Fort Nelson zone of the DSS will, at times, contain confidential information and will, therefore, be password-protected. Access to the Fort Nelson Zone of the PCOR Partnership DSS will only be granted to Fort Nelson CCS project team members and members of the PCOR Partnership that are approved by the EERC (in its capacity as the PCOR Partnership managing entity) and SET (in its capacity as owner/operator of the project site).

EXPLORATORY WELL PROGRAM

SET plans to conduct an exploratory well program in the Fort Nelson area. It is anticipated that the program will include the drilling of one well into the potential target injection formations at a location area less than 5 km from the Fort Nelson Gas Plant location, as well as the collection and analysis of rock core samples and a variety of geophysical logging data. Specific activities that are anticipated to be included in the Fort Nelson exploratory well program that may have some bearing on the characterization of geomechanical properties include the following:

- Collection of core and cuttings
  - Cuttings will be collected at 5-m intervals from a depth of 600 m from surface to total depth of the well (approximately 2265 m).
  - Cuttings will include samples from 14 formations, representing Cretaceous-, Mississippian-, and Devonian-age rocks, including all of the potential seal and sink formations.
  - Approximately 325 m of core will be collected, running from a depth of 1940 m to total depth (2265 m).
  - Core will include the Fort Simpson Group (Muskwa) and the Slave Point, Watt Mountain (if present), Sulphur Point, and Keg River Formations.
  - Core tests will include a variety of petrophysical and geomechanical parameters, including relative permeability of acid gas and brine, dynamic and static compressibility, among others.

  - The logging suite will include density, neutron, caliper, dipole sonic, and formation microimager, which will provide data on the presence and orientation of fracture systems and local stress regimes.

- Pressure transient analyses

  - Analyses will support injection design and pressure buildup/fall-off prediction.

- Initiation and completion of mini-frac tests

  - Two mini-frac tests will be conducted to evaluate the competency of two potential sealing formations, one in the Muskwa Shale and one in the Slave Point Limestone overlying the Sulphur Point Formation.

LABORATORY-BASED GEOMECHANCIAL INVESTIGATIONS

It is anticipated that core from the exploratory well will be available for testing in the summer of 2008. Sets of 1.5-inch-diameter core samples representing the cap rock and reservoir from the Fort Nelson CCS site will be provided by SET and tested for bulk density, acoustic velocity, uniaxial strength, and triaxial strength. Peak strength (at failure) and elastic properties that will be measured will include, but are not necessarily limited to, confining stress at failure, peak strength, Young's modulus, Poisson's ratio, bulk modulus, and shear modulus. Selected samples may also be tested for residual friction measurements.

In these investigations, samples will be fitted with strain gauges at 90° intervals around the core to measure the deformation observed under load. Multiple tests for various loading regimes will be carried out to define the mentioned properties. The tests will also serve for finding the parameters for several common failure criteria. These criteria are then used to predict the stress state at which failure would occur in rock. Further, the predicted values aid in determining the pore pressure buildup which can be sustained by rock without failure. The parameters for Hoek-Brown and Mohr-Coulomb criteria may also be found in the study. A brief description of these criteria follows.

The Hoek-Brown criterion is an empirical 2-D criterion, which sets limitations on major and minor principal stresses. The criterion is given by the following relationship,

$$\sigma_1 = \sigma_3 + \sqrt{m\sigma_c\sigma_3 + s\sigma_c^2} \qquad \text{[Eq. 1]}$$

where σ_1 and σ_3 are major and minor principal stresses, σ_c is the uniaxial compressive strength of the rock, and m and s are constants. Stresses σ_1 and σ_3 are defined by the pressure of overburden and tectonic forces, while σ_c and constants m and s are determined in laboratory tests.

The Mohr-Coulomb criterion also sets limitations on σ_1 and σ_3 by utilizing the concept of cohesion c and the angle of internal friction ϕ. It is given by the following formula:

$$\sigma_1 - \sigma_3 = \frac{2(c + \mu\sigma_3)}{\sqrt{\mu^2 + 1} + \mu} \qquad \text{[Eq. 2]}$$

Here $\mu = \tan\phi$ is the coefficient of friction.

Other parameters, such as uniaxial tensile strength, will also be obtained in case the use of additional failure criteria is desirable. These parameters are derived in the laboratory tests at the moment when failure of the tested sample occurs. However, degradation of the rock material starts prior to failure and should be avoided in the course of injection, if possible. In the planned study, techniques specifically measuring the acoustic wave amplitude may be employed to determine the beginning of the degradation process. Potentially, these data can be used for setting limiting conditions on the pressure buildup in the reservoir.

Criteria 1 and 2 provide useful estimates in cases where the stress tensor is known. However, stress tensor can be measured only at discrete points within the system. Alternatively, it can be estimated analytically. Both measured and analytically estimated stresses will vary significantly within the structure. Depending on the shape of the zone of porosity, which may be a reef, the existence of areas of stress concentrations may be possible. These areas are most susceptible to failure. To check for the possibility of the existence of such areas, numerical modeling accounting for the geometry of the system will be run. Calculating stresses at different points within the system requires knowledge of elastic properties, Young's modulus and Poisson ratio, of rock. Thus it is anticipated that a set of tests to derive these parameters will be run. The tests will assess two values of the parameters: one distinct in a static process (a process with no or slow development in time) and one that is distinct in the case of dynamic processes (a fast-developing process, e.g., fracturing of rock or an earthquake). These data can also be used for geophysical log calibration and have potential implications to MMV.

The results of these core analyses will provide a basis for developing accurate models that can be used to predict the effects that large-scale AGI can have on reservoir and cap rock.

SUMMARY

It is anticipated that the results of the geomechanical characterization activities described above will indicate that both reservoir and cap rock at the Fort Nelson CCS project site have sufficiently high mechanical strength to allow for the safe and effective injection of over 1 millions tons per year of acid gas. It is hoped that results will show these rocks can sustain high stresses without experiencing significant deformations and that failure of the cap rock should not occur under normal operating conditions.

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