PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP PHASE III – TASK 4: SITE CHARACTERIZATION AND MODELING

Draft Deliverable D-37 Baseline Geological Characterization Experimental Design Package – Fort Nelson Field Demonstration Site

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PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP PHASE III – BASELINE GEOLOGICAL CHARACTERIZATION EXPERIMENTAL DESIGN PACKAGE – DELIVERABLE D-37

FIELD DEMONSTRATION TEST AT FORT NELSON, BRITISH COLUMBIA

The PCOR Partnership is working with Spectra Energy Transmission 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 Spectra Energy, the Energy & Environmental Research Center (EERC), and others will conduct a variety of activities to determine the baseline geological characteristics of the injection site and surrounding areas. Spectra Energy will carry out the injection process, while the EERC will conduct CO_2 monitoring, mitigation, and verification (MMV) activities at the site. 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 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 Spectra Energy Transmission. 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

General

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 and Adams, 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 (Figure 1), Spectra Energy Transmission 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.

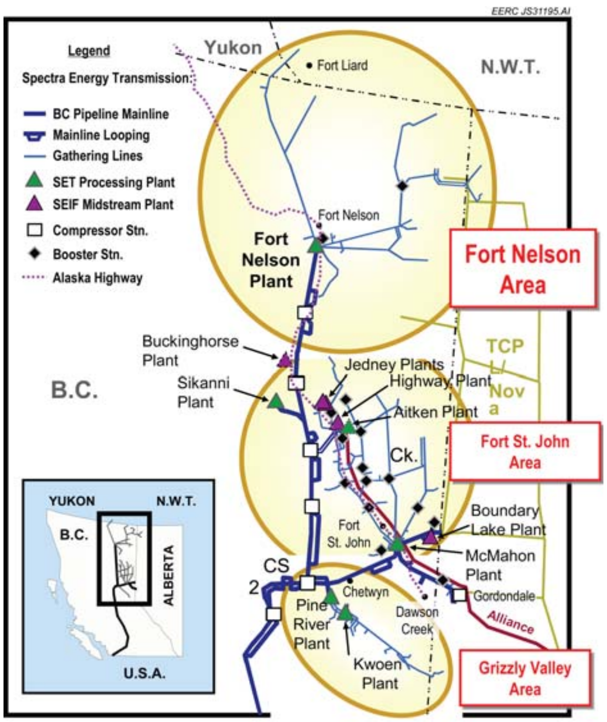

Figure 1. Location of the Spectra Energy Transmission natural gas-processing plants and infrastructure in northeastern British Columbia. The PCOR Partnership Phase III demonstration project will be conducted in the Fort Nelson area.

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 geological and hydrogeological characterization and geochemical and geomechanical sampling and 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 document the movement and fate of the injected gas stream and detect potential leakage from the storage unit.

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 U.S. federal 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 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 Spectra Energy Transmission (SET), Natural Resources Canada, and the British Columbia Ministry of Energy, Mines, and Petroleum Resources (BC MEMPR). 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.

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

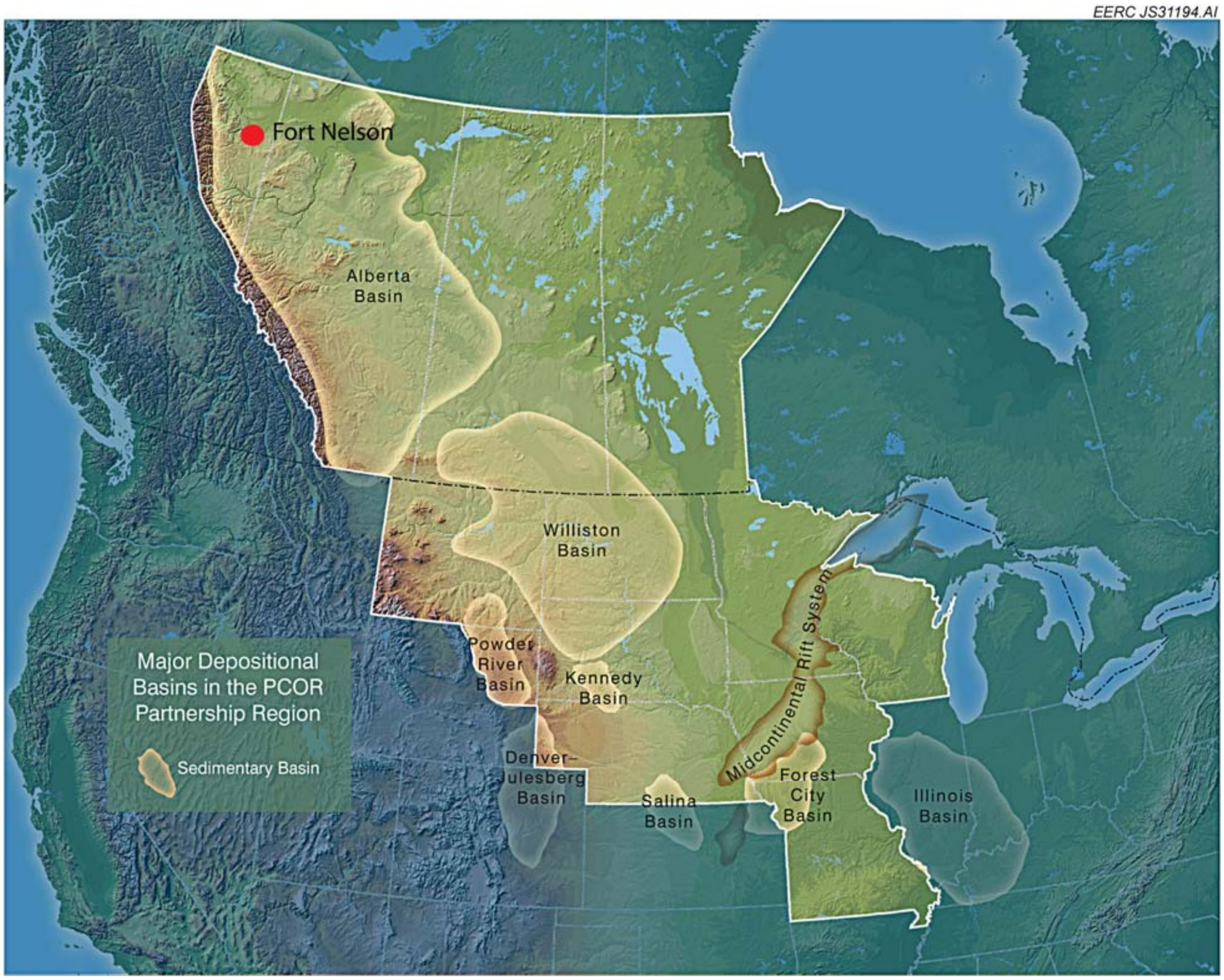

Figure 2. Sedimentary basins within the PCOR Partnership region.

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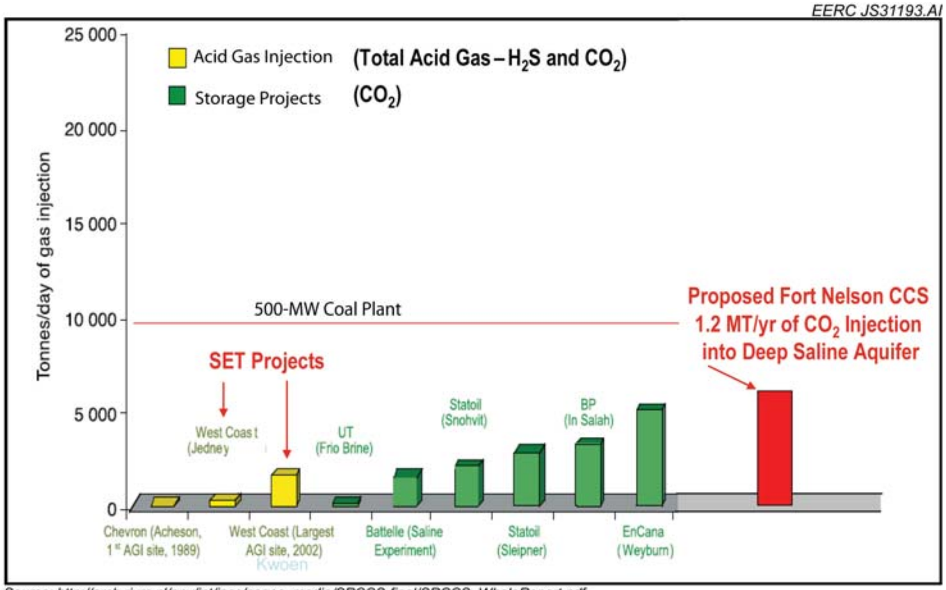

Source: http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_WholeReport.pdf

Figure 3. Relative impact of the project. Ongoing Spectra Energy Transmission acid gas injection 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.

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 initial project schedule that has been proposed by Spectra Energy. Figure 5 depicts the conceptual plan for the Fort Nelson CCS Project.

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,

Table 1. Initial Fort Nelson CCS Project Schedule as Proposed by Spectra Energy

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 check point
2008	Drill test well with core
	Conduct in situ flow tests on both saline formations
	Conduct lab tests
	Adjust reservoir model and engineering design
	Revisit business case check point + customer negotiations
	Disposal scheme application submissions and approvals
2009–2010	Project initiation and detailed design
	Drill additional wells if required + tests
	Material ordering
	Facility and pipe construction
Late 2010–2011	Initiate injection and then ramp up rates with time

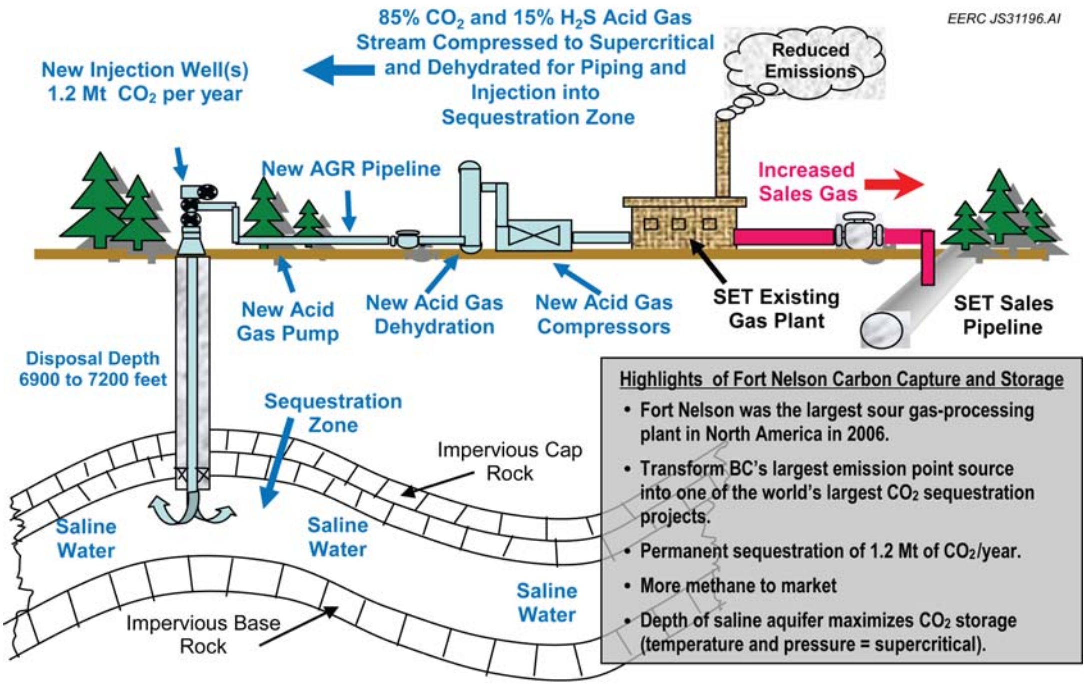

Figure 5. Fort Nelson CCS concept.

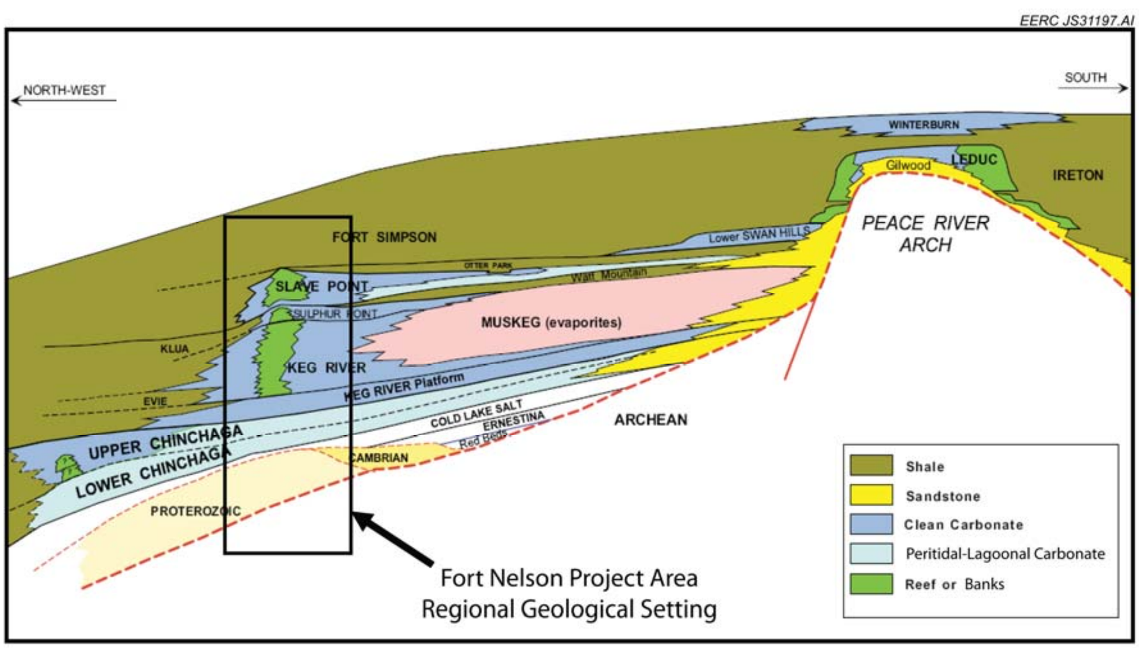

Figure 6. Stratigraphic architecture of Middle Devonian formations in the Fort Nelson area, northeastern British Columbia (BC MEMPR, 2007).

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. 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 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.

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.

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. Spectra Energy Transmission plans on

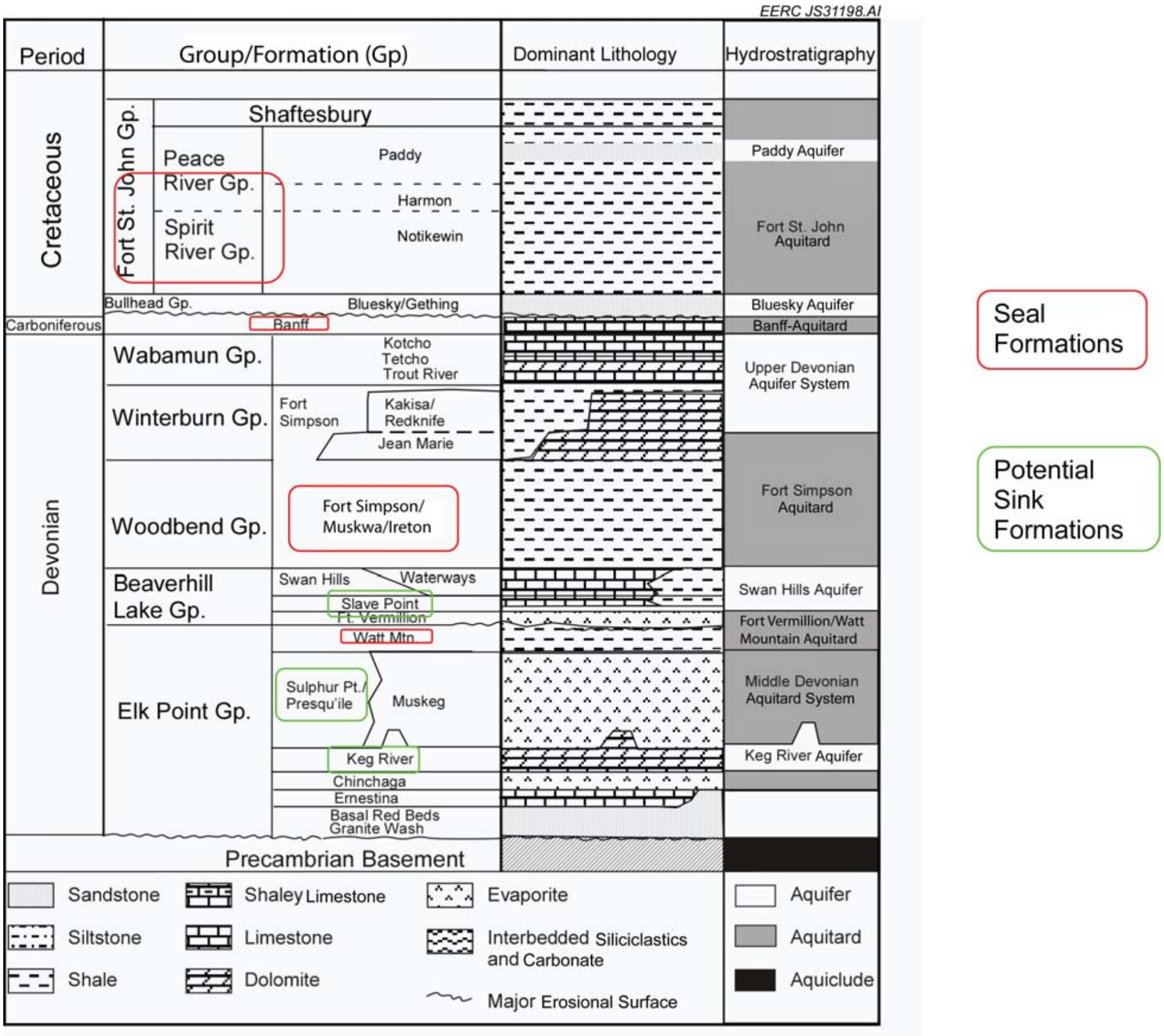

Figure 7. Stratigraphic and hydrostratigraphic delineation and nomenclature as well as general lithology for the northern part of the Alberta Basin, including northeastern British Columbia (BC MEMPR, 2007).

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

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 Spectra Energy Transmission exploratory well program at Fort Nelson is described in greater detail in the Work Plan section of this document.

PROPOSED INJECTION AND MONITORING WELLS

Spectra Energy Transmission plans on drilling one exploratory well in 2008. If the results generated by the exploratory well program indicate that large-scale injection and storage of acid gas are technically and economically feasible, then it is anticipated that the exploratory well will be converted into an injection well. The general anticipated location of the exploratory/injection well is shown on Figure 8. Spectra Energy Transmission also plans to drill a second well in relatively close proximity to the first well. The second well will be designed to serve as either a second injection well to provide backup for the first injector or as an observation well to monitor the effects of the injection on the target formation. It is anticipated that additional monitoring wells will be drilled in the area, but the precise nature (number of wells necessary, locations, depth, instrumentation, etc.) of the monitoring well network will not be determined until the baseline characterization data are gathered during Year 1. It is anticipated that plans for monitoring wells will be finalized by the middle of Phase III Year 2.

WORK PLAN

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. One important factor affecting the applicability of CCS technology to gas-processing plants throughout the world is determining the effect of H_2S concentrations on CO_2 sequestration capability and capacity and MMV. To that end, research activities related to large-scale acid gas injection into a brine-saturated formation will be conducted at the Fort Nelson plant area in British Columbia. The goal for the PCOR Partnership activities at the Fort Nelson site is to develop and implement an MMV strategy that establishes the integrity of the Devonian

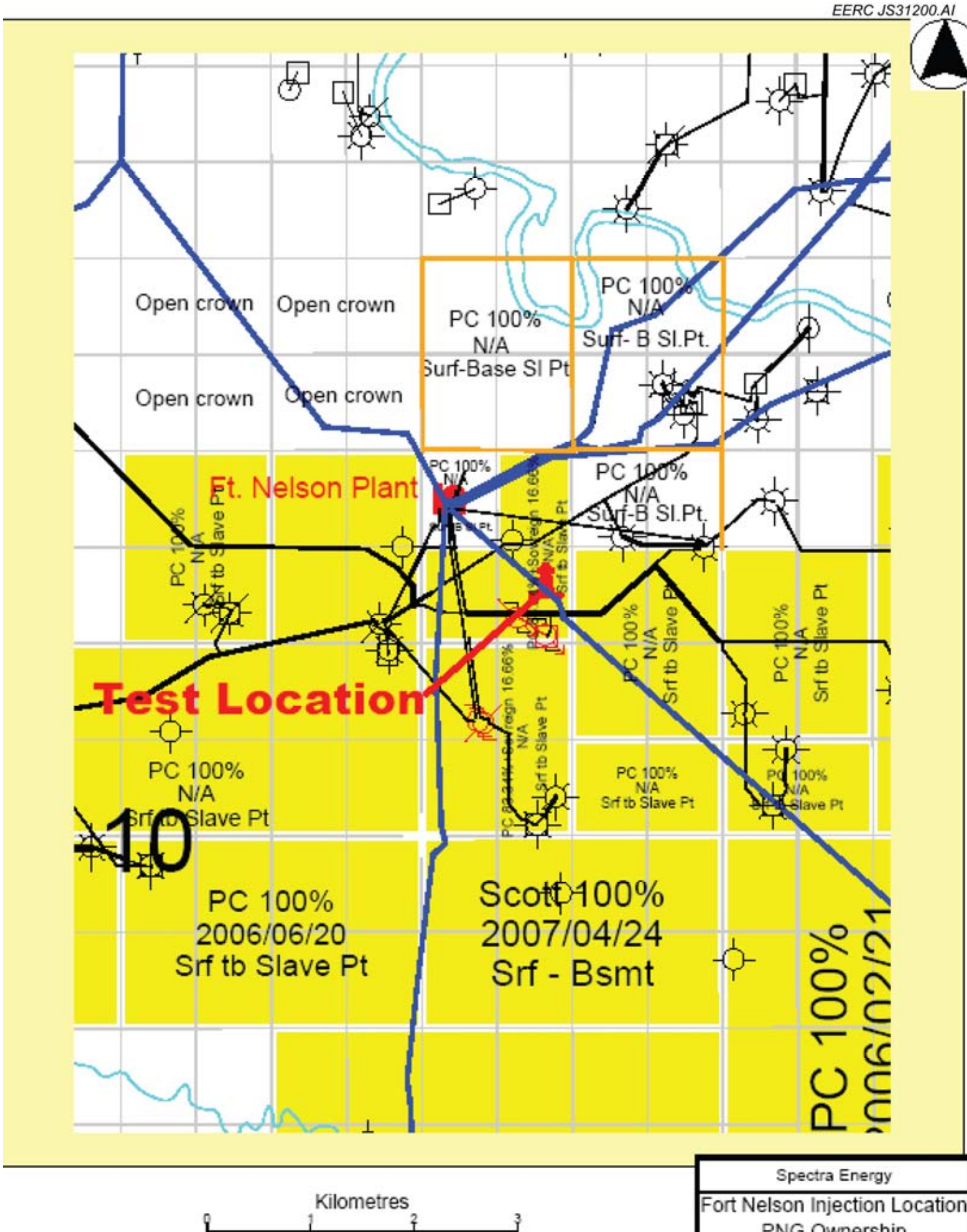

Figure 8. Site plan for Fort Nelson CCS project. The anticipated injection site is approximately 1 to 2 km southeast of the Fort Nelson Gas Plant.

carbonate formations in the Fort Nelson area with respect to large-volume CO_2–H_2S injection and storage. This will be accomplished by determining the following:

- Baseline geology
- Rock mineralogy and composition of formation water
- Baseline hydrogeology
- Mechanical rock properties and stress regime
- Nature of geochemical interactions between formation and injected fluids and reservoir rock and caprock
- Nature of wellbore integrity and leakage potential

Key characteristics affecting the long-term mobility and fate of the injected acid gas stream will be evaluated at three different scales:

- Reservoir scale (few kilometers radius from the injection site)
- Local scale (tens of kilometers radius from the injection site)
- Regional or subbasin scale (hundreds of kilometers radius from the injection site)

Work at the **reservoir scale** will focus on an area within a few kilometers radius of the injection site, with a focus on the key underlying and overlying units (i.e. Keg River, Sulphur Point, Watt Mountain, and Slave Point Formations).

Work at the **local scale** will cover an area tens of kilometers in radius from the injection site (exact area to be determined based on baseline characterization data collected during Year 1). Stratigraphically, the entire sedimentary succession from the basement to the surface will be evaluated at the local scale.

Work at the **regional**, or **subbasin scale**, will evaluate relevant data and information on key geological formations over the northwestern portion of the Alberta Basin. Hydrogeological systems and the regional continuity of key sealing formations will be the focus of studies at this large scale.

In addition, the flow regime in target injection formations may be examined at the **basin scale** to determine long-term flow characteristics and the potential for discharge over geologic time (>10,000 years).

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. Spectra Energy Transmission will provide the PCOR Partnership with much of the data sets upon which baseline characteristics will be established. The following scope is listed for Year 1 of the Fort Nelson CCS Project:

- 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, etc.

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

The existing data sets provided by SET will be integrated into the PCOR Partnership Web-based decision support system (DSS). 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 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. Figure 9 illustrates the steps that must be undertaken prior to initiating the actual drilling process (spud).

Specific activities that are anticipated to be included in the Fort Nelson exploratory well program 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.

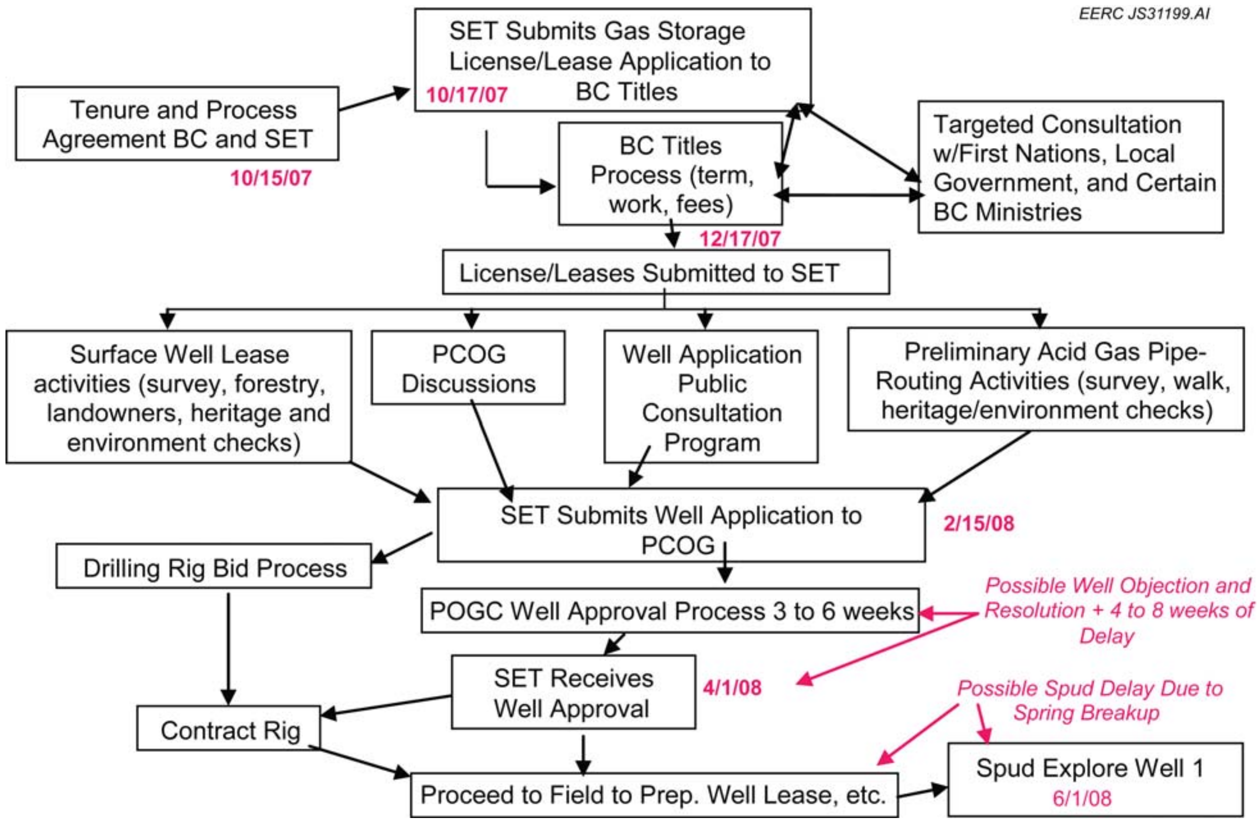

Figure 9. Sequence of events and time line leading up to a spud date for the Fort Nelson exploratory well.

- Approximately 325 m of core will be collected, running from a depth of 1940 m to total depth (2265 m).
- Core will include the Muskwa, Slave Point, Watt Mountain (if present), Sulphur Point, and Keg River Formations.
- Core tests will include a variety of permeability and geomechanical parameters, including relative permeability of acid gas and brine, dynamic and static compressibility, among others.

- Collection of formation fluids and fluid testing
  - Geochemical analysis, including total dissolved solids, anion, and cation determination.
  - Solubility verifications.
- Collection of open hole logs

- Logging suite will include density, neutron, caliper, dipole sonic, and formation micro-imager (FMI).

- Cement bond and casing integrity logging

  - Logs will support development of casing and cementing scheme design.

- Application of drill stem tests (DSTs)

  - Anticipate 3 DSTs will be conducted in the Sulphur Point and upper Keg River Formations (10-m intervals).

- Pressure transient analyses

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

- Initiation and completion of mini-frac tests

  - Anticipate two mini-fracs 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.

ANTICIPATED BASELINE CHARACTERIZATION

The following techniques will be employed over the course of the 10-year project to monitor the effects of acid gas injection in the immediate vicinity of the Fort Nelson demonstration site. These techniques will primarily be applied at the reservoir scale, but may be utilized at the local scale if appropriate and cost-effective. The preinjection state of each of these parameters will be determined using either currently available data or from field activities to acquire new data:

- To monitor the CO_2/H_2S plume:
  - Reservoir pressure monitoring
  - Wellhead and formation fluid sampling (water, gas)
  - Geochemical changes identified in observation or production wells

- To provide early warning of storage reservoir failure:
  - Injection well and reservoir pressure monitoring
  - Pressure and geochemical monitoring of overlying formations

- To monitor CO_2 concentrations and fluxes at the ground surface:
  - Monitoring for natural and/or introduced tracers

- To monitor injection well condition, flow rates, and pressures:

- Wellhead pressure gauges
- Well integrity tests
- Wellbore annulus pressure measurements
- To monitor solubility and mineral trapping:
  - Formation fluid sampling using wellhead or deep well concentrations of CO_2
  - Major ion chemistry and isotopes
  - Monitoring for natural and/or introduced tracers

- To monitor for leakage up faults or fractures:
  - Reservoir and aquifer pressure monitoring
  - Overlying formation fluid sampling (likely in the Slave Point Formation)

In addition to the collection of reservoir-focused data described above, baseline characterization activities will also be focused on determining baseline geological conditions in the Fort Nelson area with respect to the following general aspects of the site that can significantly affect reservoir injectivity, capacity, and integrity:

- Preexisting faults and/or fracture systems
- Caprock integrity
- Well casing integrity
- Formation mineralogy and geochemistry

Table 3 provides a summary and brief description of the techniques that may be applied at the Fort Nelson site and their implications with respect to the determination of baseline conditions.

BASELINE GEOLOGY DISCUSSION

At the reservoir and local scales, the goal of the proposed work is to create a geological model of the strata associated with the Middle Devonian carbonate formations to evaluate reservoir geometry and internal architecture. The overlying/surrounding caprock will also be evaluated, as well as the underlying aquifer systems that may provide reservoir support in places. Information about the geology of the injection zone and confining strata (e.g., structural setting, stratigraphy, general lithology; thickness and areal extent) will be collected, processed, and interpreted for the local scale area.

At the regional scale, the geology, stratigraphy, and lithology will be evaluated, delineated, and described for the entire sedimentary succession from the base of the Middle Devonian Elk Point Group (lower confining unit) to the surface (Lower Cretaceous Fort St. John Group and Quaternary drift) for the northwestern Alberta Basin (Figures 5 and 6). In addition, the structural elements in the area, from the basement to the surface, will be investigated to identify any possibly existing faults and/or fractures that would allow migration of reservoir and injected fluids. On this basis, a geological model of the entire sedimentary succession will be built, with particular attention given to the strata overlying the Devonian injection interval.

Table 3. Processes and Baseline Characterization Activities That May Be Conducted at the Fort Nelson Site

Testing Technique	Implication to Monitoring
Leakage Through Preexisting Fractures and/or Faults	
Measuring Initial Pore Pressure and Temperature in Reservoir and Overlying Strata	Initial pressure and temperature measurement is needed to provide baseline data for pressure and temperature monitoring during injection, which helps in the identification of leakage paths.
FMI Logs/Acoustic Logs	These logging tools can aid in the identification of fracture zones and preferential direction of natural fractures. The logs can also assist in the identification of the directions and anisotropy of horizontal stresses. Knowing in situ stress direction and magnitudes is essential in assessing fault stability and potential for mechanical failure of rock.
Minifrac/LOT	These tests allow estimating stress magnitude.
Caliper Log	Helps in the identification of any breakouts/washouts within a wellbore, which can indicate directions of horizontal stresses and mechanically weak zones.
Density Log	Allows for estimating vertical stress.
Drilling Reports Analysis	Thorough account of drilling-related events (e.g. lost circulation, tight holes, influx) can assist in the identification of mechanically weak, fractured and overpressurized zones.
Cap Rock Integrity	
Laboratory Testing of Reservoir and Cap Rock	Laboratory testing of rock allows for estimating mechanical properties (Young’s modulus and Poisson ratio) and parameters for various failure criteria. These data are required for the assessment of the possibility of rock failure.
Acoustic Logs	Allow for the estimating of dynamic mechanical properties (properties distinct in dynamic process).
Cross Borehole Tomography	Acoustic or electromagnetic tomography can provide alerts with respect to rock fracturing. Baseline data should be collected for long-term monitoring.
Borehole and/or Surface Tiltmeter Survey	Baseline data are required for using tiltmeters for alerting on rock fracturing.
Borehole Microseismic Survey	Baseline collection for microseismic monitoring, which can provide alerts on rock fracturing.
Well Casing Integrity	
Cement Bond Log	All wells existing in the zone of influence of injection operations should be logged to ensure their integrity and absence of leakage path
Structural Health Monitoring	Techniques such as cross borehole tomography or acoustic emission monitoring can assist in early alerting on cement degradation or casing corrosion.
Mineralogy and Geochemistry	
Formation Fluid Testing	Chemical composition of fluids is required for modeling potential chemical reactions. It is also needed for compatibility tests.
Rock X-ray Diffraction	These tests provide baseline data on rock mineralogy which is required for geochemical modeling and monitoring.
Surface Gravimetric Survey	Gravimetry can assist in identification of density changes in the reservoir which can accompany processes of precipitation and dissolution. Baseline data are required for monitoring.
Acid Gas Properties	Knowledge of acid gas composition and properties downhole is required for geochemical modeling.

ROCK MINERALOGY AND FORMATION WATER CHEMISTRY DISCUSSION

Rock mineralogy and the composition of injection zone fluids are important for determining potential geochemical reactions between the injected acid gas and injection formation fluids and rocks that may affect the integrity of the injection site.

Laboratory tests will be conducted on core samples to assess the geochemical reactions between the injected gas and the rocks and fluids of the reservoir and seal. When the exploration well is drilled in the Fort Nelson area, it is anticipated that a portion of the seal, transitional zone, and reservoir rock will be cored and used for mineralogy and other testing. The results will provide data regarding 1) potential mineralization that may occur and 2) the partitioning of CO_2 and H_2S between oil, formation waters, and rocks (reservoir and seal).

BASELINE HYDROGEOLOGY DISCUSSION

Identifying and characterizing the hydrogeological regime at an acid gas–CO_2 injection site is important to understand possible migration pathways and the effect the flow of formation water may have on the spread of the injected gas. Several aquifer systems (Figure 6) are present in the sedimentary succession overlying the Middle Devonian Elk Point Group: 1) the Swan Hills Aquifer, which includes the Devonian Slave Point Formation, which also contains hydrocarbon-bearing reservoirs in the area; 2) the Upper Devonian Aquifer, which includes carbonates of the Winterburn and Wabamun Groups; and 3) isolated sand aquifers in the shales of the Lower Cretaceous Fort St. John Group (Bluesky and Paddy Formations). The following information will be collected at both local and regional scales:

- Hydrostratigraphic delineation
- Aquifer and aquitard geometry and thickness
- Rock properties relevant to the flow of formation waters and injected acid gas such as porosity and absolute and relative permeability
- Geothermal regime
- Pressure regime
- Direction and strength of formation water flow

A model of the flow-driving processes and mechanisms in the region and strata of interest will be developed that will help in understanding the effect of natural flow on flow paths in the Elk Point Group interval and outside, in case of leakage, and also of the effect of injection on the system.

GEOCHEMICAL MODELING

The goal of this activity is to model the interaction between the injected gas, the reservoir fluids, and the rocks to determine 1) the potential amount of CO_2 and/or H_2S that may be stored through mineral precipitation and 2) the effects of mineral precipitation on permeability and injectivity. A mineralogical assessment of core samples will be performed to predict the amounts and nature of mineral trapping of the injected gas. Mineral compositions will be obtained using an electron microprobe. Powdered core samples will be analyzed by scanning electron microscopy techniques, XRD, and x-ray fluorescence. The compositional data will be used to perform geochemical modeling to assess the long-term fate of acid gas in the subsurface.

WELLBORE INTEGRITY AND LEAKAGE POTENTIAL

Well bores constitute a critical element with regard to the disposal and storage of acid and greenhouse gases because they may provide a leakage pathway. It is not possible to determine the "exact" state of all well bores; consequently, the approach will be to combine both "real" field data and analytical or numerical simulations to quantify processes associated with the hydraulic integrity of the wells. Statistical well geometry and performance data within the pilot and surrounding regions will be compiled from available databases. A database of project-specific well data will be constructed from detailed review and synthesis of available well file information. Based on this information, probabilistic assessments of wellbore integrity issues under the conditions of CO_2 injection and long-term buoyancy-driven forces will be evaluated.

GEOMECHANICAL PROPERTIES AND STRESS REGIME

The goal of this activity is to establish the geomechanical properties of the reservoir and caprock 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. Project activities may include in situ stress orientation and magnitude analysis, including log-based analysis of rock mechanical properties and geomechanical modeling.

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