BELL CREEK TEST SITE – BASELINE HYDROGEOLOGICAL EXPERIMENTAL DESIGN PACKAGE

Plains CO_2 Reduction (PCOR) Partnership Phase III
Task 4 – Deliverable D34

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BELL CREEK TEST SITE – BASELINE HYDROGEOLOGICAL EXPERIMENTAL DESIGN PACKAGE

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership is working with Denbury Onshore LLC (Denbury) to determine the effect of the large-scale injection of carbon dioxide (CO_2) into a deep clastic reservoir for the purpose of simultaneous CO_2 enhanced oil recovery (EOR) and CO_2 storage. A technical team that includes Denbury, the Energy & Environmental Research Center (EERC), and others will conduct a variety of activities to determine the baseline hydrogeological characteristics of the injection site and surrounding areas. Denbury will carry out the injection process, while the EERC will conduct CO_2 monitoring, verification, and accounting (MVA) activities at the site. The Bell Creek demonstration project will be a unique opportunity to develop a set of cost-effective MVA protocols for large-scale (>1 million tons per year) combine CO_2 EOR and storage in a clastic formation. The baseline geological characterization work that will be conducted over the course of this project will also provide valuable data to support the design and implementation of an injection/production scheme for large-scale CO_2 EOR and storage.

The field demonstration test conducted in the Bell Creek area of Powder River County, Montana, will evaluate the potential for CO_2 EOR and storage. The CO_2 will be obtained from the Lost Cabin gas-processing plant in Fremont County, Wyoming, and injected into a sandstone reservoir in the Lower Cretaceous Muddy (Newcastle) Formation at a depth of approximately 4500 feet (1372 meters). The Lost Cabin Gas Plant is owned and operated by ConocoPhillips. The plant currently generates approximately 50 million cubic feet of CO_2 per day (Figure 1). The activities at Bell Creek will inject an estimated 1.1 million tons of CO_2 annually, much of which will be permanently stored.

BACKGROUND

Carbon capture and storage (CCS) in geological media has been identified as an important means for reducing anthropogenic greenhouse gas emissions into the atmosphere (Bradshaw and others, 2006). Several means for geological storage of CO_2 are available, including depleted oil and gas reservoirs, deep brine-saturated formations, CO_2 flood EOR operations, and enhanced

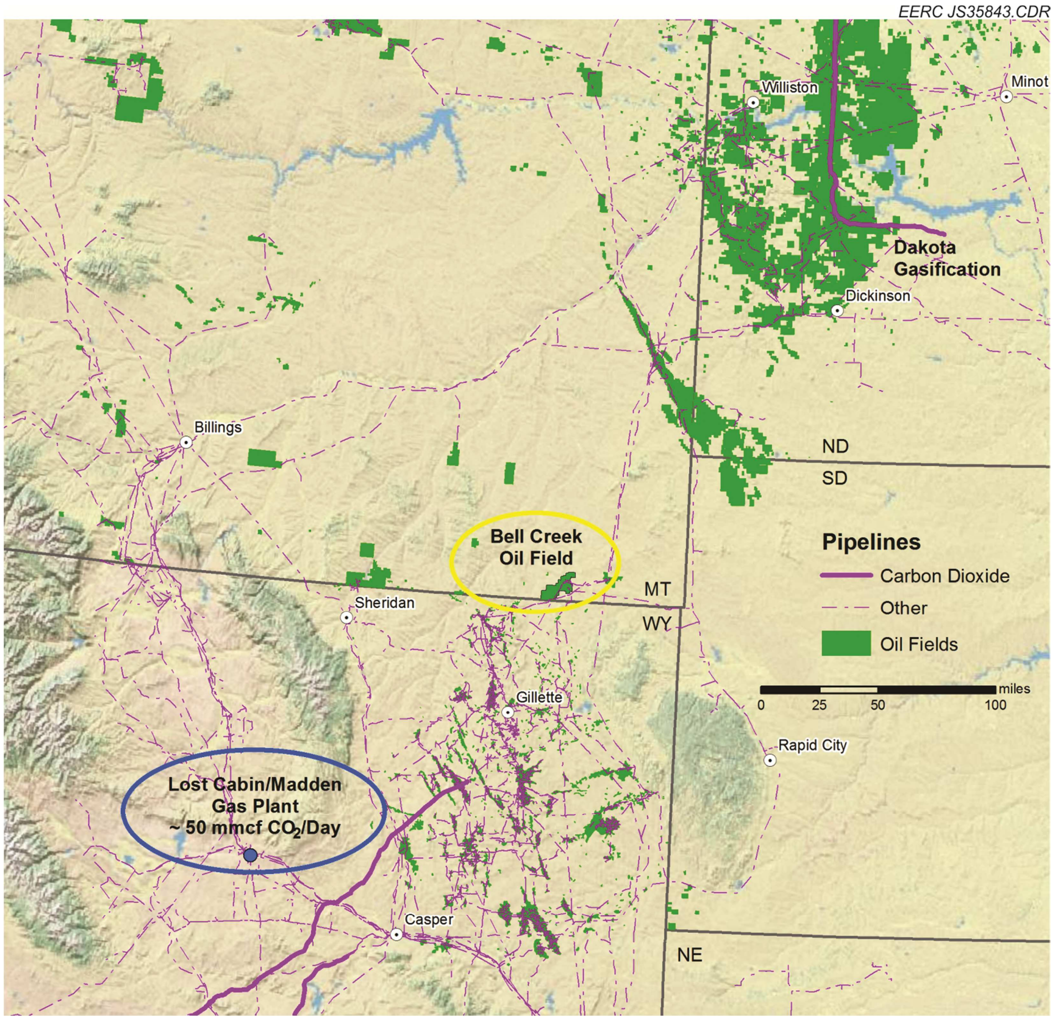

Figure 1. Location of the Lost Cabin Gas Plant and Bell Creek oil field in Wyoming and Montana.

coalbed methane recovery. The U.S. Department of Energy (DOE) is pursuing a vigorous program for demonstration of CCS technology through its Regional Carbon Sequestration Partnership (RCSP) 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 2017), and its main focus is the characterization and monitoring of large-scale CO_2 injection into geological formations at CCS sites. Regional characterization activities conducted by the PCOR Partnership indicate that oil reservoirs represent significant opportunities in North America for both long-term storage of CO_2 and incremental oil production through EOR (Peck and others, 2007). The opportunity to cost-effectively store CO_2 while simultaneously producing incremental oil, as a value-added product, provides the basis for conducting the Bell Creek EOR and CCS project as part of the PCOR Partnership's Phase III program.

The PCOR Partnership, covering nine U.S. states and four Canadian provinces, is assessing the technical and economic feasibility of capturing and storing CO_2 emissions from stationary sources in the central interior of North America. The PCOR Partnership's goal is to identify and test CCS opportunities in the central interior of North America. The partnership comprises numerous private and public sector groups from the nine states and four provinces, among them Denbury and ConocoPhillips. The 10-year Phase III program proposed by the PCOR Partnership aims to demonstrate the efficacy of large-scale CO_2 storage coupled with commercial EOR operations at the Bell Creek location. It is anticipated that the results generated at the Bell Creek site will provide insight and knowledge that can be directly and readily applied to similar projects throughout the world. The Bell Creek oil field is one of many oil and gas reservoirs in the PCOR Partnership region that has the potential to store significant amounts of CO_2. Initial estimates suggest that approximately 14 million tons of CO_2 may be stored in the Bell Creek oil field as a result of EOR activities. The results of the proposed Phase III test will be broadly applicable throughout the PCOR Partnership region:

- Ten of the 13 state/provincial jurisdictions in the region have oil fields within their boundaries.

- Regional characterization activities conducted under Phases I and II of the PCOR Partnership show that there are hundreds of oil fields in the region that may be suitable for CO_2-based EOR operations.

- Phase I results indicate that in the PCOR Partnership region at least 3.5 billion tons of CO_2 is needed to produce the incremental oil in the fields that were identified as being suitable for CO_2-based EOR.

- Oil fields generally offer the best opportunities to implement large-scale CO_2 storage projects in a timely manner because they are generally much better characterized than saline formations; are already legally established for the purpose of safe, large-scale manipulation of subsurface fluids; and offer a means to offset the considerable costs of CO_2 capture and transportation through the sale of incrementally produced oil.

Developing cost-effective approaches to predict and determine the fate of the injected CO_2 is an important aspect of implementing large-scale CCS technology. Baseline characterization and MVA activities are critical components of geological CCS projects for two key reasons. First, the public must be assured that CO_2 geological storage is a safe operation. Second, to facilitate the establishment and trading of carbon credits, markets need assurance that credits are properly assigned, traded, and accounted for. Integrated programs that combine robust geological, hydrogeological, geochemical, and geomechanical characterization activities can generate results that can be used to establish baseline conditions at the site in question. Detailed knowledge of the geological characteristics of a site are then used to develop a cost-effective MVA plan. 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. The baseline geological data will also be used to support the design of the CO_2 injection and oil production scheme for the Bell Creek project.

Demonstrating the technical and economic viability of implementing cost-effective, risk-based MVA strategies at a large-scale (>1 million tons of CO_2 per year) commercial CO_2 EOR project such as the Phase III Bell Creek project will provide stakeholders with the real-world data necessary to move CCS technology deployment forward. The results generated by the Bell Creek project will provide stakeholders, including policy makers, regulators, industry, financiers, and the public, with the knowledge necessary to make informed decisions regarding the real cost and effectiveness of CCS as a carbon management strategy.

PROJECT OBJECTIVES

From the perspective of CCS, the primary project objectives are to demonstrate that 1) CO_2 storage can be safely and permanently achieved on a commercial scale in conjunction with an EOR operation; 2) oil-bearing sandstone formations are viable sinks for CO_2; 3) MVA methods can be established to effectively monitor commercial-scale EOR CO_2 storage projects and to provide a technical framework for the monetization of carbon credits; and 4) the lessons learned and best practices employed will provide the data, information, and knowledge needed to develop similar CO_2 EOR storage projects across the region. A thorough understanding of the hydrogeological characteristics of the Bell Creek oil field and its surrounding area is necessary to achieve these objectives.

With respect to CO_2 EOR, the primary objective of the PCOR Partnership at Bell Creek is to provide Denbury with technical support that adds value to its planned operations. The acquisition of baseline hydrogeological characterization data as described in this experimental design package will provide Denbury with data that will support the development of effective injection and production schemes.

HYDROGEOLOGIC BACKGROUND

Geologic Setting

The Bell Creek oil field in southeastern Montana (Figure 1) lies within the northeastern corner of the Powder River Basin. The sedimentary succession in the Bell Creek area consists primarily of sandstones and shales. A stratigraphic column of the portion of the Powder River Basin within which the Bell Creek oil field is located is provided in Figure 2.

Exploration activities for mineral and energy resources in the area over the last 55 years have yielded a significant amount of information about the geology of southeastern Montana. The Bell Creek oil field is an ideal candidate for a CO_2 tertiary recovery project for a variety of reasons. First, its depth provides adequate temperature and pressure conditions for maintaining injected CO_2 in a supercritical state and may support the maintenance of miscibility of CO_2 and oil. Also the high-porosity and permeability conditions of the reservoir allow for high CO_2 injection rates and a fairly rapid production response. Finally, the Bell Creek oil reservoir is overlain by multiple units of thick, competent shales which will serve as seals to prevent vertical migration of CO_2.

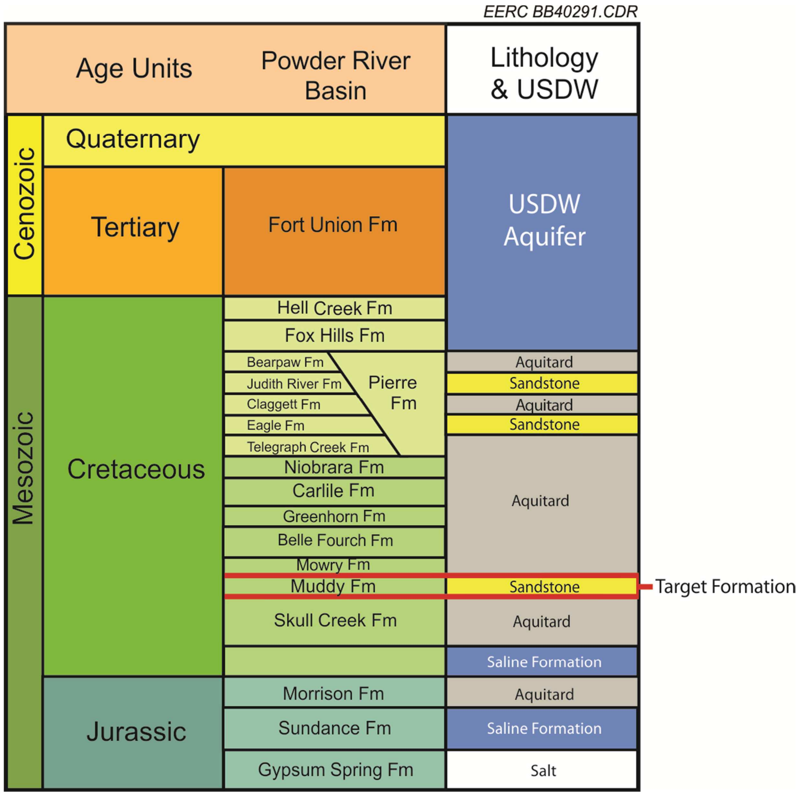

Figure 2. Stratigraphic column of the Powder River Basin, Montana (Montana Bureau of Mines and Geology, 2007).

Hydrocarbon production in the Bell Creek area, in the form of crude oil, is primarily from stratigraphic traps in the Lower Cretaceous-age Muddy Formation, sometimes referred to as the Newcastle Formation. While the two terms are used interchangeably and both have been used to describe the reservoir at Bell Creek, this report and all subsequent project reporting materials will refer to the rock unit as the Muddy Formation. It is anticipated that the clastic reservoirs within the Muddy Formation will be the primary target injection zones for the Bell Creek CO_2 EOR and storage project.

In the Bell Creek area, the Muddy Formation is dominated by clean sandstones deposited in a near-shore marine environment that have porosity and permeability characteristics that should be adequate for large-scale CO_2 injection. Structurally, the Bell Creek oil field is a monocline with a 1° dip to the northwest and whose axis trends southwest to northeast for a distance of approximately 20 miles. Stratigraphically, the Muddy Formation in the Bell Creek oil field features an up-dip facies change from sand to shale that serves as a trap. The sand bodies of the reservoir are dissected and, thus, somewhat compartmentalized by intersecting shale-filled channels.

The shale formations of the overlying Upper Cretaceous Mowry Formation will provide the primary seal, preventing leakage to overlying underground sources of drinking water (USDW) or the surface. Overlying the Mowry Formation are several low-permeability shale formations, including the Upper Cretaceous-age Belle Fourche, Greenhorn, Niobrara, and Pierre Shales which will provide additional layers of protection from leakage to the surface or USDWs.

No areas of faulting or fracturing have yet been identified in the Bell Creek study area. However, the intermontane nature of the Powder River Basin, which is known to have areas of significant faulting and fracturing, suggests that such features may exist in proximity to the planned injection area.

Hydrologic Setting

The Bell Creek Field lies within the Northern Great Plains Aquifer System, which covers approximately 300,000 square miles. This system comprises five major aquifers. These aquifers include the lower Tertiary, Upper Cretaceous, Lower Cretaceous, Upper Paleozoic and Lower Paleozoic, aquifers. The aquifer system lies underneath nearly all of North and South Dakota, as well as half of Montana and nearly a third of Wyoming. Climate plays a major role in this system, as much of the recharge can be attributed to rainfall and snowmelt; therefore, shallow groundwater levels reflect both short- and long-term precipitation patterns. The Bell Creek region has a continental climate that is cold in the winter, warm in the summer, and has large variations in seasonal precipitation. Annual precipitation ranges from 10 to 20 inches.

Recharge to the groundwater system occurs from infiltration of direct precipitation, runoff in creek valleys, and standing water in playas and impoundments. Direct infiltration of precipitation provides a minimal source of recharge over most of the area because it is limited by the climate and surface features. Infiltration can be significant in areas of more permeable surface geologic units. Infiltration of surface water in creek valleys is considered the most important source of recharge to the underlying alluvium and shallow bedrock aquifers, but it is difficult to quantify in a predominantly ephemeral drainage system.

Surface Water

Because of the lack of precipitation, surface water is limited in this region. Surface water consists of perennial and intermittent streams, ponds (natural and stock), and springs. The bulk of surface water is captured and held in stock dams for livestock production. As in most semiarid areas, the concentration of dissolved materials in effluent streams generally increases with distance downstream.

Groundwater

Three distinct groundwater flow patterns are present in the Powder River Basin: shallow and deep bedrock flow systems and alluvial aquifers. Locally, recharge along high, clinker-capped ridges produces shallow bedrock flow systems that follow topography. This local recharge either discharges to alluvial aquifers, forms springs at bedrock outcrops, or seeps vertically into the deeper bedrock aquifers. Alluvial aquifers consist of unconsolidated sediments in valleys. As part of this project, a detailed groundwater well analysis, including depth, completion, and water quality, will be performed.

Powder River County Groundwater Wells

The majority of the Bell Creek Field lies in Powder River County. Of the 3707 groundwater wells registered (Montana Groundwater Information Center, GWIC) in the county, more than 90% are stock wells. Most of the wells are relatively shallow (<500 feet) and are completed in the Fort Union Formation (Tables 1 and 2).

Bell Creek Field Groundwater Wells

There are 83 groundwater wells in the Bell Creek Field that are registered with the state of Montana (GWIC). The wells typically fall into two categories: drinking water wells and livestock production wells. Groundwater levels in this system vary greatly because of seasonal precipitation and physical well location (lowland or upland). Static water levels range from 25 to 330 feet below ground surface throughout the Bell Creek region.

HYDROGEOLOGIC CHARACTERIZATION

Hydrostratigraphic Delineation

In order to adequately assess the influence hydrogeologic conditions may have on injected CO_2, the hydrogeologic system will have to be defined and analyzed. A hydrostratigraphic unit can be defined as a part of a body of rock that forms a distinct hydrologic unit with respect to the flow of groundwater. Delineation of these units subdivides the geologic framework into relatively more or less permeable portions and thus aids in definition of the flow system. Delineation of hydrostratigraphic units at the regional scale involves the application of:

- Lithostratigraphic and sequence stratigraphic concepts to the deposits in order to derive an overall conceptual framework of the strata.
- Subsurface mapping using cores, driller’s logs, and geophysical logs to define lithofacies.
- Laboratory testing of core samples of aquifer and aquitard units.
- Porosity and permeability comparisons between lithologies in the geologic framework.
- Limited information on the effect of geologic history including diagenetic processes and tectonics on the geologic properties.
- Analysis of existing studies.

A wide variety of log data are available for the field because of extensive oil and gas exploration. These data are acquired along the length of the borehole and can be used to identify porous and nonporous layers. Once calibrated and combined with other potentially available data, the subsurface hydrostratigraphy can be delineated.

Table 1. Powder River County Well Depths

Powder River County Groundwater Wells	
Total Depth, ft	Number of Wells
0–99	1064
100–199	1036
200–299	660
300–399	332
400–499	237
500–599	146
600–699	115
700–799	38
800–899	27
900–999	30
>1000	22

Table 2. Powder River County Well Completions

Powder River County Groundwater Wells Geologic Formation		
	Number of Wells	Geologic Age
Alluvium (quaternary)	94	Quaternary
Tongue River Member (of Fort Union Formation)	1424	Tertiary
Tullock Member (of Fort Union Formation)	1078	Tertiary
Fort Union Formation	30	Tertiary
Canyon Coal Overburden – Fort Union Formation	3	Tertiary
Canyon Coal of the Fort Union Formation	6	Tertiary
Knoblock Coal of the Fort Union Formation	4	Tertiary
Lower Knobloch Coal of the Fort Union Formation	2	Tertiary
Knobloch Coal Underburden – Fort Union Formation	3	Tertiary
Lance–Hell Creek Undifferentiated	272	Upper Cretaceous
Hell Creek Formation	12	Upper Cretaceous
Fox Hills–Hell Creek Aquifer	10	Upper Cretaceous
Fox Hills Formation or Sandstone	4	Upper Cretaceous
Shannon Sandstone Member (of Cody or Steele shale)	18	Upper Cretaceous
Judith River Formation (of Montana Group)	2	Upper Cretaceous
Eagle Sandstone	3	Upper Cretaceous
Muddy Sandstone Member (of Thermopolis shale)	4	Lower Cretaceous
Minnelusa Sandstone or Formation	4	Pennsylvanian
Mission Canyon Limestone (of Madison Group)	2	Mississippian
Madison Group or Limestone	3	Mississippian

Aquifer and Aquitard Geometry and Thickness

Once the hydrostratigraphy is delineated, the geometry (extent, thickness, dip, etc.) of aquifer and aquitard units in and around the Bell Creek Field can be defined. A thorough understanding of these properties is necessary to develop accurate assessments of subsurface flow. Flow paths through the Muddy Formation system will be determined by the geometric relationships of higher permeable zones (aquifers) and lower permeable zones (aquitards). Aquitards are distinguished from sealing formations in this activity as those which may impede but not preclude flow. Aquitards are likely to remain somewhat permeable, although at a factor reduced from surrounding aquifer units.

Aquifer units are expected to be relatively extensive and well-connected across the field, although there may be areas where aquifer units become more isolated and dominated by aquitard lithology. Areas with a greater occurrence of aquitard units may be of interest for both EOR and CCS activities, as they could contain greater quantities of oil left behind from previous production activities and may be capable of storing a greater quantity of CO_2 because of decreased internal flow or isolated flow paths.

A regional understanding of aquifer and aquitard geometry will also be necessary to determine regional flow paths. This analysis will identify how naturally occurring flow enters and exits the Bell Creek Field and how this flow may impact the long-term migration of injected fluids. The hydrostatic regime will be defined by identifying the geometry (extent, thickness, dip, etc.) of aquifer and aquitard units in and around the Bell Creek Field. This work will be accomplished primarily through analysis of geophysical well log data, existing cores taken from the area, and data from previous activities. Once the key units are defined, they will be mapped and incorporated into a geologic model of the study area developed using Schlumberger's Petrel software package.

Rock Properties Relevant to the Flow of Formation Waters and Injected CO_2

The distribution of rock properties (primarily porosity and permeability) is primarily controlled by the geologic processes that lead to deposition of the sediments. Subsequent diagenetic processes (i.e., fracturing, faulting, or dissolution) can also impact the current distribution of porosity and permeability. Although directly observable in core samples and inferred from well log data, geologic modeling of these properties is most likely to produce realistic interpretations across the field and region. Geologic modeling affords the opportunity to project the heterogeneity observed from the wells in all directions at once. Geologic interpretations can then be applied to these distributions in order to more accurately predict how they vary over the extent of the field.

On a macroscale, the distribution of these properties, in part, determines the distributions of aquifer and aquitard units discussed above. An understanding of the distribution of these properties in the microscale aids in the prediction of the effectiveness of various CO_2-trapping mechanisms. In particular, the effectiveness of residual gas trapping will be dependent on the geometry of individual pores. In residual gas trapping, CO_2 remains trapped within individual pores once the primary CO_2 plume has migrated beyond that point. This is the result of the interactions of capillary pressure and interfacial tension which does not allow the isolated CO_2 bubble to pass through the confining pore throat.

During this investigation, data will be collected on rock properties relevant to hydrogeologic flow. Data related to rock porosity, absolute and relative permeability, and the variance in these properties will be interpreted from well logs, cores, and well files. These data will then be mapped, analyzed, and incorporated into a geologic model of the study area.

Geothermal Regime

The geothermal regime of a sedimentary basin is the sum result of various heat sources and transport mechanisms which transfer heat energy from the deep interior to the surface. There are two predominant sources of heat; 1) that which originates from deep inside the Earth and is transferred to the crust from the mantle and 2) that which results from the decay of radioactive isotopes (Bachu and Burwash, 1994). This heat is transferred through a basin primarily by conduction and convection of moving fluids within the basin. The transport of heat may be dominated by either conduction or convection or neither may dominate. The interaction of these phenomena will determine how heat is distributed throughout the basin. Various processes may manifest themselves at different scales, a factor which should be taken into account in a detailed analysis of a geothermal regime (Bachu and Burwash, 1994).

Downhole temperature data will be collected and analyzed during this activity in order to map and define the geothermal regime in and around the injection zone. While a general geothermal gradient can be assumed for predicting downhole temperature, a more detailed analysis is preferred as temperature can have an impact on injection activities. For example, the reservoir temperature can influence the density of injected CO_2 and thus influence the effectiveness of local seals (Covault and others, 2011). Data related to the geothermal regime will also be incorporated into the geologic model in order to analyze its potential impact on injection activities and leakage migration pathways.

Pressure Regime

Hydraulic head is generally considered the primary forcing mechanism in the migration or flow of formation fluids. Movement of water through a porous medium is the result of driving forces acting on the fluid medium (fluid moves from areas of higher pressure to areas of lower pressure). Pressure can be driven by physical conditions (hydraulic potential), temperature conditions (thermal potential), and chemical conditions (chemio-osmonic potential), and together these forces are known as total potential (Fetter, 2001).

Hydraulic potential comprises elevation and pressure head and is the dominant driving force in the majority of subsurface environments. This force, which generally originates as flow from higher to lower elevation and/or higher to lower pressure, is typically defined as the amount of work required to transport a unit mass of fluid between two specified points (Fetter, 2001). Thermal potential results from the existence of strong thermal gradients in the subsurface. Chemio-osmotic potential can be generated when groundwaters of different salinities exist on either side of a unit of shale (Fetter, 2001). In this instance, shale may act as a semipermeable membrane, allowing only the fluid component of the water to migrate from the lower-salinity groundwater to the higher-salinity groundwater. This force can be large, depending on subsurface physical and chemical conditions, but typically dominant only on a basin scale.

Generally, the dominant component of total potential in sedimentary basins is hydraulic potential, which is expected to be the dominant force in the Bell Creek region.

The distribution of hydraulic head will be determined primarily from drillstem test (DST) data collected as part of oil and gas exploration in the field. These data will likely need to be adjusted to account for variations in salinity of the formation fluid. Therefore, the distribution of salinity within the field will also need to be analyzed. Once collected, these data can be analyzed, mapped, and modeled. This information will be used to help identify native flow. Identification of areas that deviate from expected hydrostatic conditions (i.e., over- or under-pressured zones) will also be of interest.

Direction and Strength of Formation Water Flow

By combining the various analyses presented above (hydrostratigraphy, geometry, rock properties, thermal regime, and pressure regime), the native flow in and around the Bell Creek Field can be analyzed, mapped, and modeled. Accurate identification of these patterns is key to understanding potential impacts of injection as well as potential migration pathways in the event of leakage from the system. Of particular interest in this effort will be to identify flow patterns between the identified aquifer and aquitard units. A determination of the strength of this flow is also important for determining the potential influence it will have on the migration of injected CO_2. The flow regime is also important for evaluating the potential for hydrodynamic trapping and, to a less degree, solubility-trapping mechanisms.

CONCLUSION

In addition to other baseline characterization activities, a hydrogeological evaluation will be carried out to determine what influence existing hydrogeological conditions may have on the injection and storage of CO_2 at the Bell Creek Field test site. This activity will be carried out by delineating the hydrostratigraphic units in the region, determining the regional geometry and thickness of the hydrostratigraphic units, evaluating the range and distribution of rock properties that influence natural flow in the system, evaluating the geothermal and pressure regimes of the system, and determining the strength and direction of groundwater flow. The results of this evaluation will include the development of a regional hydrostratigraphic column, a hydrostratigraphic model populated with aquifer and aquitard rock properties, maps of the geothermal and pressure regimes, and formation flow maps based on simulation results and previous hydrogeologic evaluations. Each of these outputs and associated data will be described in a final report to Denbury and DOE. It is expected that the results of these activities will influence the development of the EOR injection plan and the deep- and near surface-MVA plans.

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