ZAMA ACID GAS EOR, CO_2 SEQUESTRATION AND MONITORING PROJECT

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ABSTRACT

A comprehensive monitoring, mitigation, and verification (MMV) plan is being implemented at the Zama Oil Field in northwestern Alberta, Canada, to determine the effect of acid gas injection for the simultaneous purpose of disposal, sequestration of CO_2, and enhanced oil recovery (EOR). The injection process and hydrocarbon recovery will be carried out by Apache Canada Ltd. while the Energy & Environmental Research Center (EERC) through the Plains CO_2 Reduction (PCOR) Partnership (one of seven U.S. Department of Energy Regional Carbon Sequestration Partnerships) will conduct the MMV activities at the site. Research activities are being conducted at multiple scales of investigation in an effort to validate the ultimate fate of the injected gas. Geological, geomechanical, geochemical, and engineering work is being used to fully describe the injection zone and adjacent strata. Certifying the integrity of the caprock is a critical research area, with additional tests being completed on the reef to determine the nature of potential geochemical and geomechanical changes that may occur because of acid gas exposure. Fluids will be sampled at the producing horizon and directly above the horizon to ensure containment through active and inactive wells in the pinnacle. A perfluorocarbon tracer is being used to track fluid flow throughout the system and to identify leakage should it occur. With over 800 pinnacles in the Zama Field, the potential for long-term sequestration is significant.

INTRODUCTION

The Energy & Environmental Research Center (EERC), through the Plains CO_2 Reduction (PCOR) Partnership, one of the U.S. Department of Energy's (DOE's) National Energy Technology Laboratories Regional Carbon Sequestration Partnerships (RCSP), is working with Apache Canada Ltd. and the Alberta Geological Survey to evaluate the use of acid gas (H_2S and CO_2) injection for the simultaneous purpose of acid gas disposal, sequestration of CO_2, and enhanced oil recovery (EOR). Activities will take place in northwestern Alberta, Canada, at the Zama oil field (Figure 1). The injection process and subsequent hydrocarbon recovery will be carried out by Apache Canada Ltd., while the EERC will conduct measurement, mitigation, and verification (MMV) activities at the site with as little disruption to the ongoing oil production as possible. The MMV activities have been designed in such a way as to be cost-effective while still providing critical data on the behavior and fate of the acid gas mixture.

This test will evaluate the potential for geological sequestration of CO_2 as part of a gas stream that includes high concentrations of H_2S. The results of the Zama activities will provide insight regarding the impact of H_2S (20% to 40% of the acid gas stream) on sink integrity (i.e., seal degradation), MMV, and EOR success within a carbonate reservoir.

In this project, acid gas is injected through wells into the top of pinnacle reef structures which have been depleted of oil from primary and secondary (water flood) oil production techniques. The reef is repressurized using the acid gas, and incremental oil is produced from a second well in the reef completed near the oil–water contact (Figure 2). Additional inactive wells are used to monitor acid gas migration uphole and, in some cases, the effect of the acid gas on the completed wellbore.

The acid gas will be obtained from the Zama gas-processing plant and injected into a pinnacle reef at a depth of approximately 4900 feet (1500 meters). Solution gas produced from Keg River oil pools contains approximately 5% CO_2 and 3% H_2S. The plant also processes nonassociated gas, which contains 13% H_2S and 8% CO_2. An amine extraction system generates an effluent stream that is approximately 70% CO_2 and 30% H_2S. The plant currently generates about 6.2 million cubic feet of acid gas per day (352 tons). This amounts to a total of about 250 tons/day of CO_2 and 100 tons/day of H_2S. Previously, a portion of this effluent was processed through a Claus unit to generate elemental sulfur which was then sent to a sulfur block (Figure 3). The rest was injected for disposal into the Keg River Formation using nearby acid gas injection wells. Both of these operations have currently been suspended as the entire acid gas stream is being utilized for EOR. As of December 2006, four pinnacles are receiving acid gas, with PCOR Partnership monitoring activities currently taking place on one.

In all, Apache Canada Ltd. plans to develop a total of nine to ten pinnacles for EOR. Breakthrough of acid gas to the production wells is recycled back into the project pinnacles or injected into an acid gas disposal well completed into the Keg River Aquifer. Apache anticipates the capability to add one or two pinnacles a year to the project, should the first few pinnacles prove economically feasible. Over a period of 16 years, about 1.3 megatonnes of CO_2 and about 0.5 megatonnes of H_2S could be sequestered into the first nine to ten pinnacles. With respect to EOR, it is anticipated that the acid gas miscible flood will ultimately yield between 180,000 and 276,000 barrels of incremental oil recovery a year.

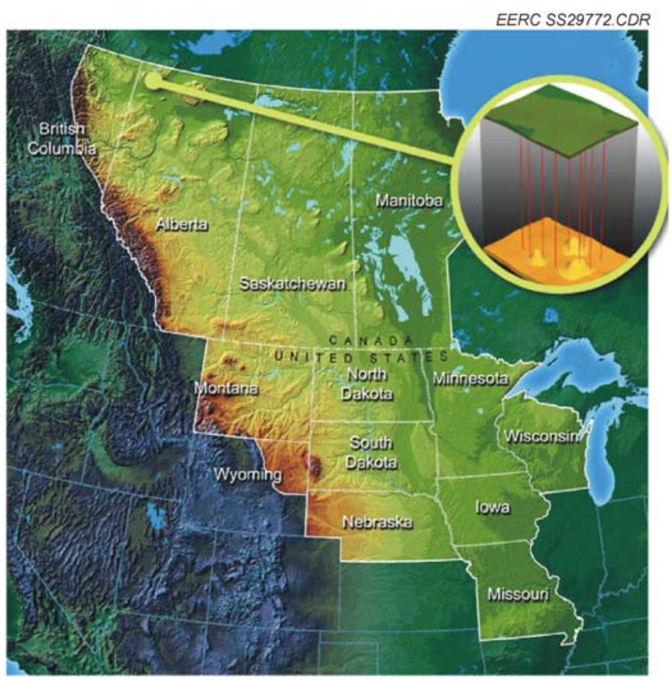

Figure 1. Location of field validation test in the Zama Field of Alberta.

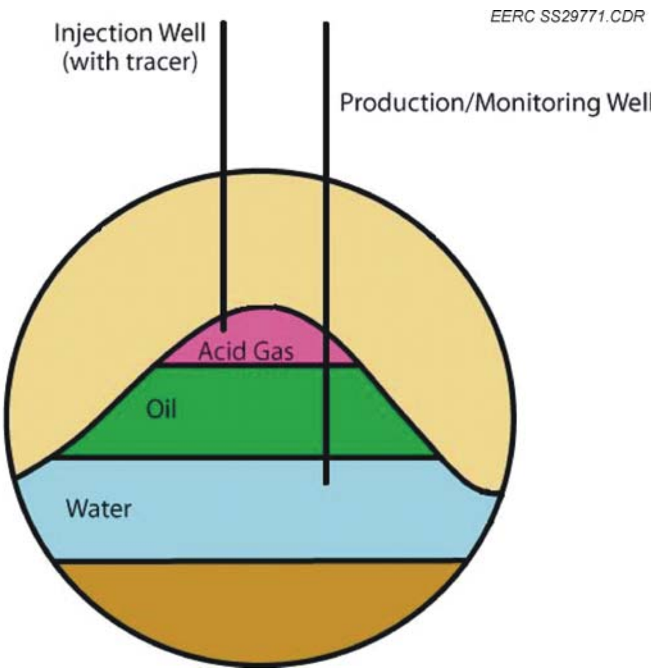

Figure 2. Illustration of top-down injection and production scheme

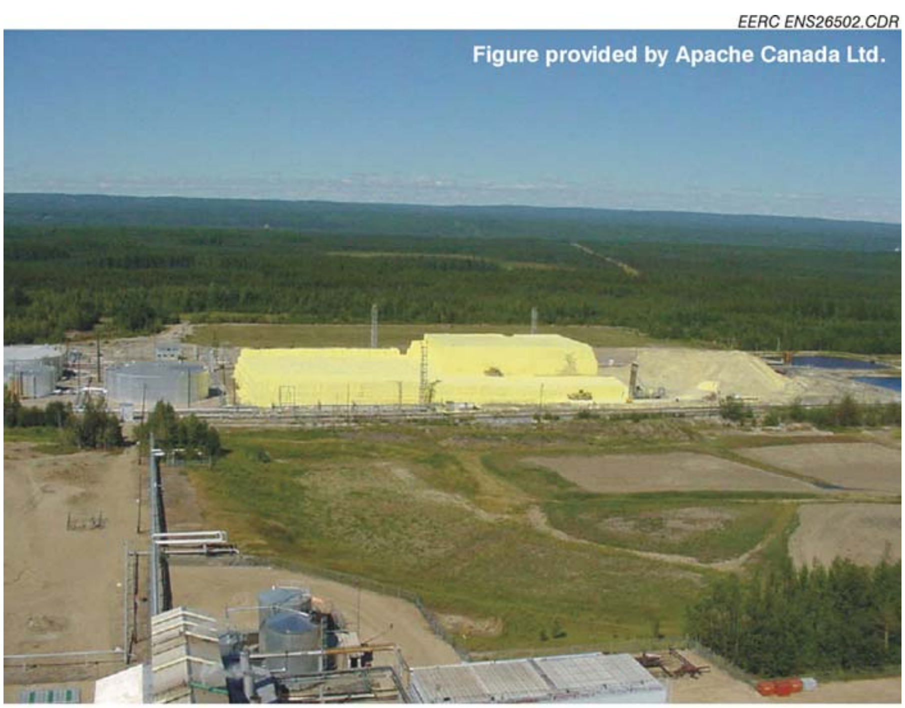

Figure 3. Elemental sulfur accumulating as a result of acid gas processing.

BACKGROUND

General

Carbon dioxide capture and storage (CCS) in geological media has been identified as an important means for reducing anthropogenic greenhouse gas emissions currently vented to the atmosphere. 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 in depleted oil and gas reservoirs, in deep saline formations, in CO_2-flood EOR operations, and in enhanced coalbed methane recovery. Studies in CO_2 capture, transportation, storage, and MMV have been, and continue to be, pursued to allow for the deployment of large demonstrations. Understanding 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 sampling and analysis programs are technologies that can document the movement of the injected gases and detect potential leakage from the storage unit.

Through enhanced resource recovery methods, CO_2 storage can provide an economic benefit. For instance, to encourage the development of a CO_2-storage industry in Alberta, the Alberta Department of Energy (ADOE) has instituted a royalty credit program that offers a royalty reduction to companies that use CO_2 in EOR and meet certain qualification criteria. Apache Canada Ltd. was successful in its application to ADOE for a royalty credit and in December 2006 started to inject acid gas into a pinnacle reef structure referred to as the Zama F Pool. The PCOR Partnership MMV activities are primarily focused on the Zama F Pool.

While the Canadian and Alberta 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 RCSP Program, which entered Phase II in October 2005. The PCOR Partnership, covering nine U.S. states and four Canadian provinces, proposes to 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 is currently comprised of nearly 70 private and public sector groups. Among them the U.S. DOE, the Alberta Energy and Utilities Board (AEUB), Natural Resources Canada (NRCan), Alberta Environment, and Apache Canada Ltd have made significant contributions that are focused specifically on the Zama demonstration. The 4-year Phase II program being undertaken by the PCOR Partnership aims to demonstrate the efficacy of CO_2 sequestration in a variety of subsurface and terrestrial settings at four locations, among them being the acid gas EOR project run by Apache Canada Ltd. in the Zama oil field. While the setting and conditions are unique, it is anticipated that the results generated at the Zama site will provide insight and knowledge that can be applied throughout the world.

In March 2007, the Zama project was nominated by the United States and Canada for recognition by the Carbon Sequestration Leadership Forum (CSLF) as an official geological CO_2 sequestration project. Established in 2003, the CSLF is an international climate change initiative that is focused on development of improved cost-effective technologies for the separation and capture of carbon dioxide for its transport and long-term safe storage. The organization is made up of two groups focused on the technical and policy gaps associated with CO_2 storage and have currently recognized 19 projects. The Zama project was officially recognized by the Carbon Sequestration Leadership Forum (CSLF) in April, 2007. The Zama project will address the following Projects Interaction Review Team (PIRT) Gaps Analysis, which is one of the selection criteria for recognition:

- **Reservoir engineering aspects** – Challenges in dealing with acid gas as a miscible fluid for EOR and the ultimate sequestration of associated CO_2 will be identified in the project.

- **EOR lessons to be applied to other storage reservoirs** – Acid gas which is increasingly being produced as deeper sour gas pools are produced, could be used for additional EOR projects, thereby increasing energy supplies from remote, dispersed, and smaller oil pools that do not justify major CO_2 infrastructure.

- **Depleted oil and gas fields viability** – The utilization of depleted oil fields for sequestration purposes will be validated throughout the life of this project. In addition, as recovery is from carbonate pinnacle reefs, using a different strategy than in the case of reservoirs of large lateral extent, if successful, could be applied to other similar reservoirs elsewhere.

THE ZAMA OIL FIELD

The Zama oil field in northwestern Alberta (Figure 4) covers an area of about 300,000 acres (1200 km^2) in the Middle Devonian Zama subbasin (Figure 5). The sedimentary succession in the Zama subbasin 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).

Oil production is primarily from reservoirs in pinnacle reefs of the Middle Devonian Keg River Formation (Figure 6). These reef buildups were formed in a lagoon partially surrounded by carbonate banks and fronted by the Presqu’ile barrier to the west (Figures 5 and 8). To date, over 400 pinnacles have been discovered in the Zama subbasin. The pinnacles are on average about 40 acres (0.16 km^2) in size at the base and about 400 ft (120 m) high. They typically consist of dolomite of variable porosity and permeability and are surrounded and overlain by anhydrite of the Muskeg Formation. While some Keg River pinnacle reefs have grown directly on the underlying low-permeability Lower Keg River carbonate platform (Figure 8), resulting in hydraulic isolation of the individual pinnacle reservoirs, others rest on higher-permeability Keg River bank facies which hydraulically connects several pinnacles, resulting in pressure support from an active water drive. The average reservoir depth is 5000 ft (1500 m), with a hydrostatic initial reservoir pressure of 2175 psi (15 MPa) and temperatures of 160° to 185°F (70° to 85°C).

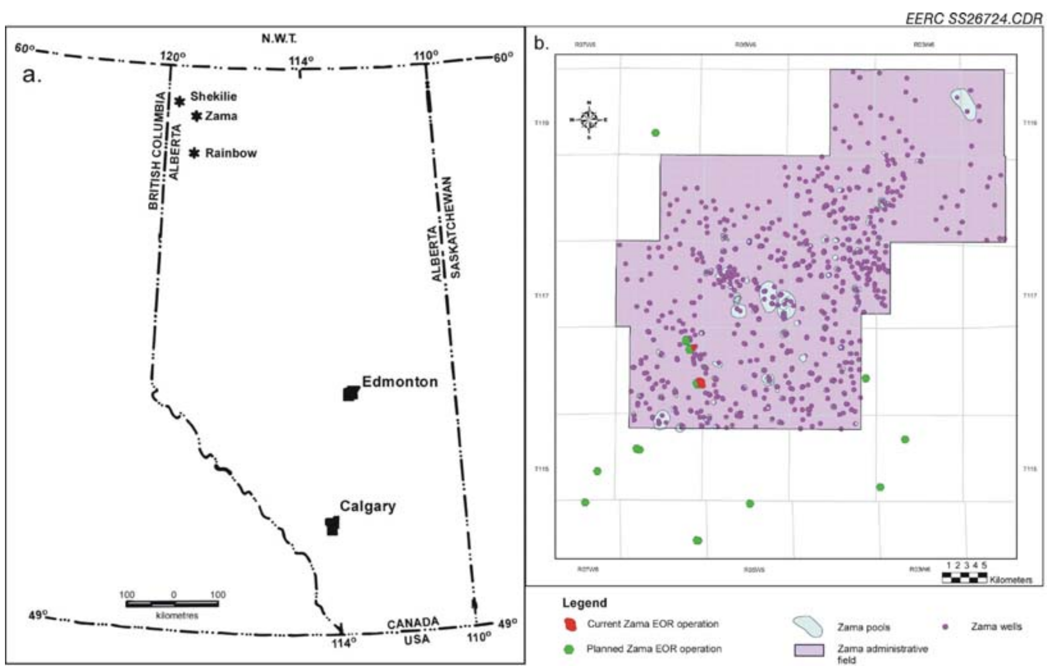

Figure 4. Location of the acid gas EOR project at Zama: a) Keg River hydrocarbon fields in northern Alberta (Apache Canada Ltd., 2003) and b) the Apache Canada Ltd. Zama-Keg River acid gas EOR sites in the Zama oil field. Well locations shown are those where the Keg River Formation was penetrated.

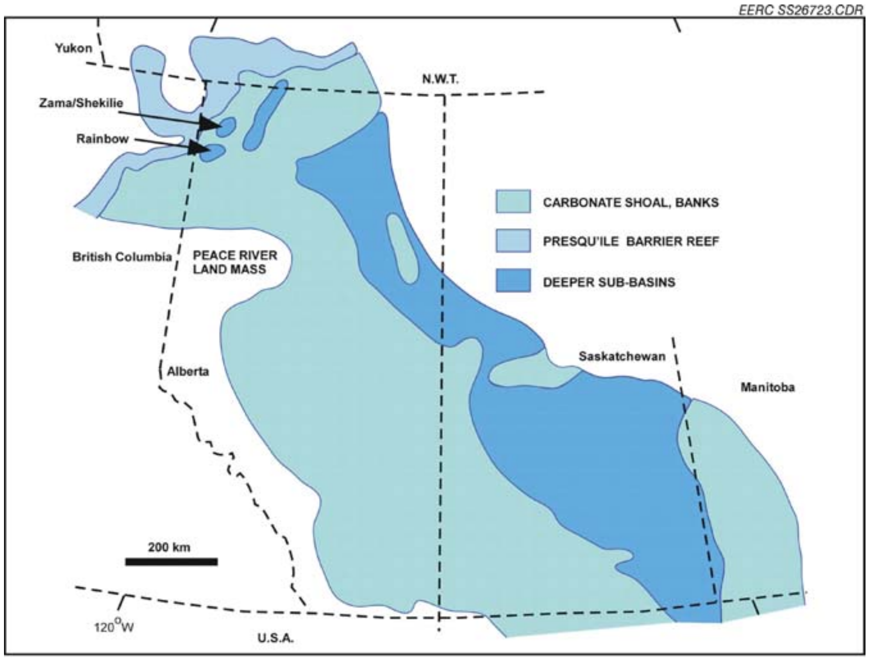

Figure 5. Simplified paleogeography for the Keg River carbonate sequence of the Middle Devonian Elk Point Basin in western Canada. Open marine shales lie to the northwest of the Presqu'ile barrier reef (modified after Davies and Ludlam, 1973).

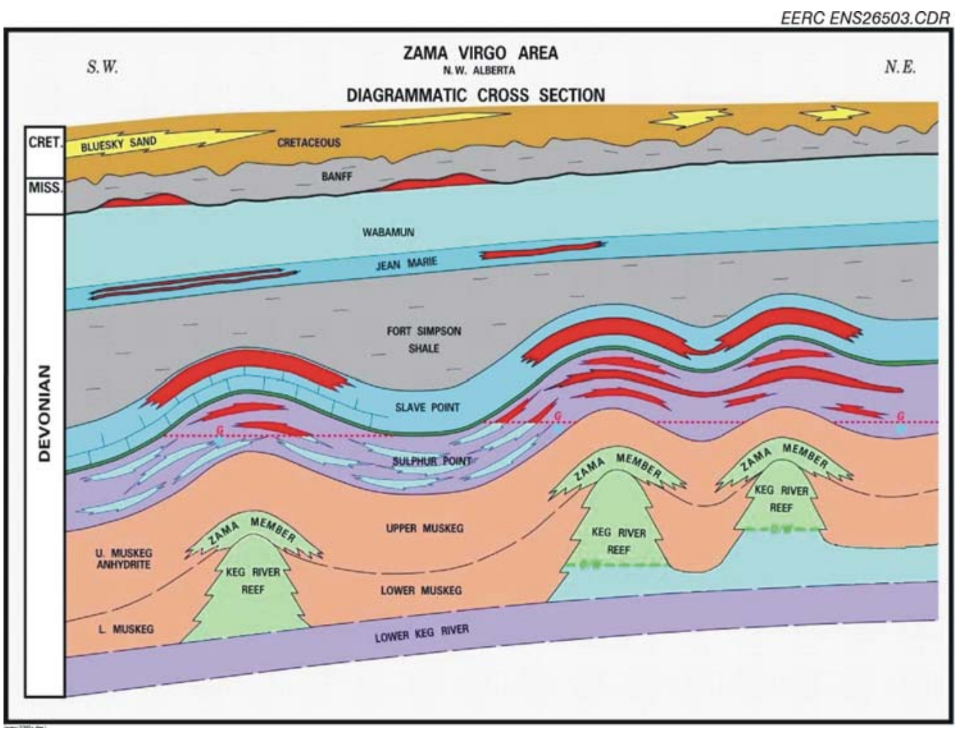

Figure 6. Schematic cross section illustrating the sedimentary succession in northwestern Alberta. Also shown are oil and gas occurrences.

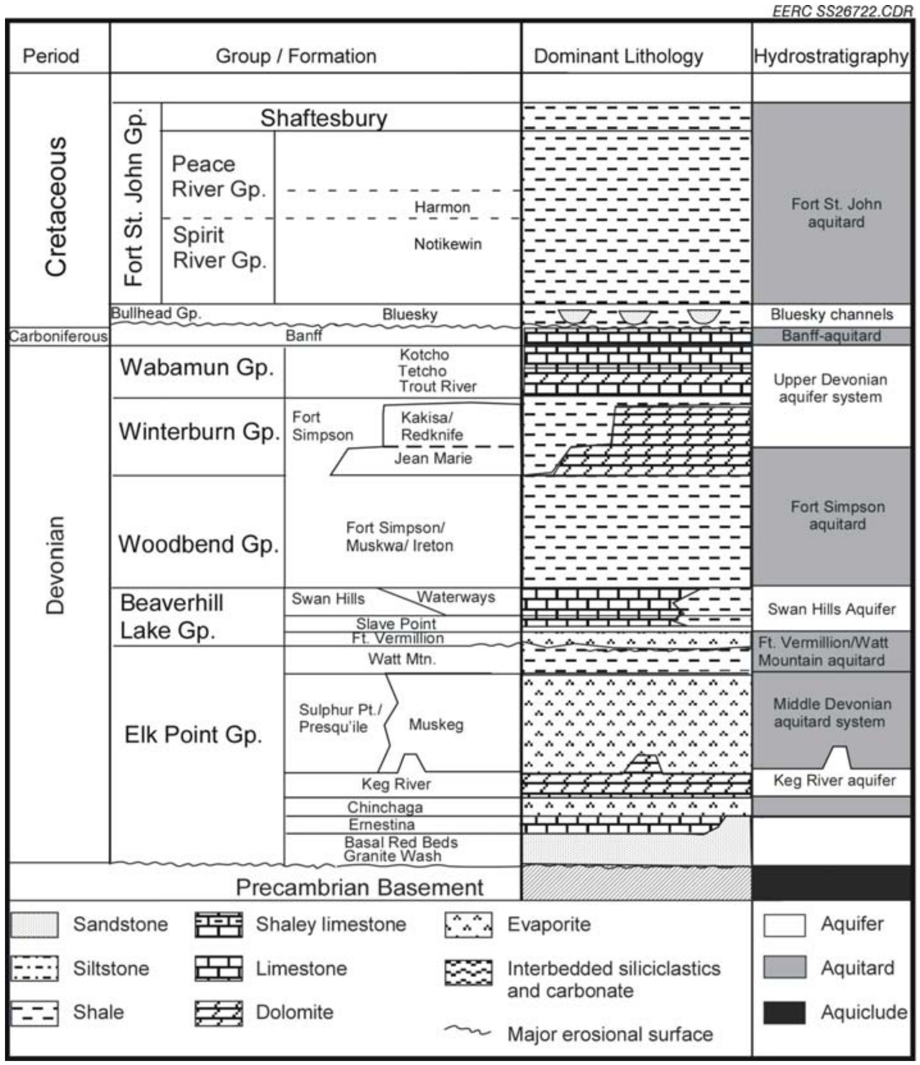

Figure 7. Stratigraphic and hydrostratigraphic delineation and nomenclature as well as general lithology for the northern part of the Alberta Basin.

RESERVOIR HISTORY AND CHARACTERISTICS

The F Pool was discovered in 1967 and brought on production in February of that year. A pressure volume temperature (PVT) sample was taken in October of 1967 by the Hudson's Bay Oil and Gas Company Limited and analyzed by Core Laboratories in November of 1967 (Apache Canada Ltd., 2003). The original reservoir pressure (Table 1) was recorded as 2095 psig (14,447 kPa) at a datum depth of −3605.3 ft (−1098.6 m) MSL. By November of 1968, special core analysis was conducted on core samples taken during drilling of the 11-25 well (Apache Canada Ltd., 2003). Routine core analysis was performed on the 8-13-116-6W6 discovery well.

During the 1990s, the F pool was shut in. This resulted in reservoir pressure being recharged as a result of water injection activities in nearby Keg River Formations. In December of 2004 reservoir pressure was measured to be in the vicinity of 2466 psi (17,000 kPa) at the reservoir datum depth. Reservoir pressure was reduced a further 2 MPa (to 15,000 KPa) between July 2005 and February 2006 in order to comply with EUB requirements before initiating acid gas injection. Oil production commenced November 1967. A summary of cumulative recoveries is shown in Table 2.

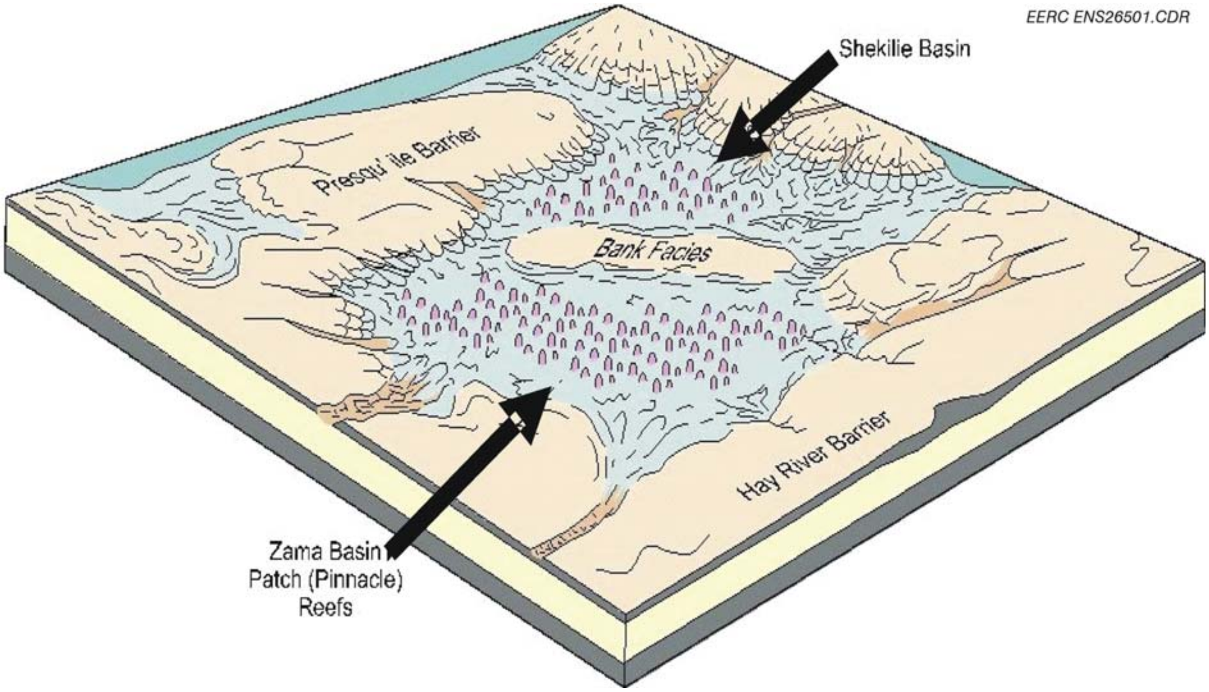

Figure 8. Schematic block diagram showing the Zama and Shekilie subbasins in northern Alberta.

Table 1. Initial Conditions

Play Type	Keg River Pinnacle Reef
Initial Reservoir Pressure	2095 psi (14,447 kPa)
Reservoir Temperature	160°F (71°C)
Initial Water Saturation	15% (from logs)
Porosity	10% (from logs)
Initial Gas Oil Ratio	52 m^3/m^3
Initial Formation Volume Factor	1.183 r vol/stdvol
Bubble Point Pressure	1275 psi (8791 kPa)
API Gravity	35.2 API
Calculated OOIP	2.2 million bbl 344,000 m^3 (volumetric using 3-D seismic data)
Calculated OOIP	3.5 million bbl 557,000 m^3 (material balance)

Table 2. Cumulative Recoveries to November 2003

Oil	1,107,512 bbl	176,100 m^3
Gas	533,604,614 ft^3	15,110,000 m^3
Water	405,647 bbl	64,500 m^3
Water Injection	2,304,329 bbl	366,400 m^3

CHARACTERIZATION ACTIVITIES

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 an oil production site that is using acid gas as a tertiary recovery mechanism for the purposes of EOR and CO_2 sequestration. One important factor is the effect of H_2S concentrations on EOR, CO_2 sequestration capacity, and MMV. Research activities related to acid gas injection will be conducted at the Zama F pool in the Zama oil field, Alberta. The goal for the PCOR Partnership activities at the Zama site is to develop and implement an MMV strategy that establishes the integrity of the Zama pinnacle reefs for CO_2–H_2S storage. This will be accomplished by carrying out the following activities:

- Baseline geology

- Rock mineralogy and composition of formation water

- Baseline hydrogeology

- Mechanical rock properties and stress regime

- Assessment of geochemical interactions between formation and injected fluids and reservoir rock and caprock

- Assessment of wellbore integrity and leakage potential

The proposed work will be carried out at three different scales:

- Reservoir scale
- Local scale
- Regional or subbasin scale

Work at the **reservoir scale** will focus on the Zama F oil pool and the immediately underlying and overlying confining units: Lower Keg River Formation limestone and Muskeg Formation anhydrite.

Work at the **local scale** will cover, areally, the Zama F Pool and a few adjacent pinnacle reefs (to be determined during the project) and, stratigraphically, the entire sedimentary succession from the basement to the surface.

Work at the **regional**, or **subbasin scale**, will focus on evaluating relevant data and information from the basement to the surface over the entire Zama oil field/subbasin.

In addition, the flow regime in the underlying Keg River Aquifer may be examined at the **basin scale** to determine discharge area and flow characteristics.

BASELINE GEOLOGY

At the reservoir and local scales, the purpose of the proposed work is to create a geological model of the strata associated with the Middle Devonian Keg River Formation at the F Pool EOR site to evaluate reservoir geometry and internal architecture. The Keg River pinnacle reef reservoirs are confined above by 70 m of Muskeg/Prairie Formation evaporites and underlain by the Lower Keg River carbonate platform, which consists of tight lime-mudstone and a slightly porous limestone. The carbonates are also underlain by about 70 m of Chinchaga Formation evaporites. The overlying/surrounding caprock will also be evaluated, as well as the underlying aquifer that provides reservoir support in places. Information about the geology of the reservoir 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 Zama subbasin (Figures 5 and 7). 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 Keg River injection interval.

Rock mineralogy and the composition of reservoir and aquifer fluids are important for determining potential geochemical reactions between the injected acid gas and reservoir/aquifer fluids and rocks that may affect the integrity of the injection site. Laboratory tests will be conducted on new and previously existing core samples to assess the geochemical reactions between the injected gas and the rocks and fluids of the reservoir and seal. A portion of the seal, transitional zone, and reservoir rock were cored in March, 2007, and will be 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).

Identifying and characterizing the hydrogeological regime at an acid gas–CO_2 injection site are important to understand possible migration pathways and the effect the flow of formation water may have on the spread of the injected gas. At least two saline aquifers (Figure 6) are present in the sedimentary succession overlying the Middle Devonian Keg River Formation: the Upper Devonian Slave Point formation and Jean Marie formation, which also contain hydrocarbon-bearing reservoirs in the area (Figure 4). Isolated sands may be present in the shales of Lower Cretaceous Fort St. John Group. Information regarding the hydrostratigraphic delineation, aquifer and aquitard geometries, rock properties, geothermal regime, pressure regime, and flow strength and direction will be collected at both local and regional scales. These data are being utilized to generate a model of the flow-driving processes and mechanisms in the region and strata of interest that will help in understanding the effect of natural flow on flow paths in the Keg River interval and outside, in case of leakage, and also of the effect of injection on the system.

MECHANICAL ROCK 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. This is a critical issue, as the regulatory agency (EUB) currently does not allow injection pressures greater than the original reservoir pressure. The limited reservoir pressures allowed will affect the miscibility and oil recovery. 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 dissolution areas at a scale much larger than the seismic surveys. This information will help to elucidate the geological history of the reservoir and identify possible natural leakage paths like faults. Project activities will include in situ stress orientation and magnitude analysis, including log-based analysis of rock mechanical properties and geomechanical modeling.

MMV OPERATIONS

The development and execution of effective MMV operations are a critical element in conducting large-scale injection projects. Successful MMV activities will result in data sets that 1) verify that injection operations do not adversely impact human health or the environment and 2) validate the sequestration of greenhouse gases for the purpose of developing and ultimately monetizing carbon credits. There is a broad range of technologies and approaches that can be and, in some cases, have been applied to CO_2 sequestration projects of various scales around the world. Early geological sequestration research and demonstration projects deployed MMV strategies that were developed based on a lack of knowledge about the effectiveness and utility of many of the applied technologies. The absence of knowledge required early projects to gather as much data as possible using a variety of techniques. In particular, a desire to "see" the plume of injected CO_2 led to a strong emphasis on the use of geophysical data, especially 3-D and 4-D seismic, to monitor the plume. While the use of seismic-based techniques in early projects yielded valuable results that are essential to the development of geological sequestration as a CO_2 mitigation strategy, their high costs of deployment and often limited ability to identify CO_2 in many geologic settings will likely render them as being the exception rather than the rule when it comes to developing MMV plans for future projects.

If the deployment of large-scale CO_2 injection for geological sequestration is to become widespread, then MMV activities must be cost-effective. In many geological settings, expensive geophysical surveys should not be the centerpiece of MMV strategies. The use of existing data sets to develop background and baseline conditions should be maximized wherever possible. The use of invasive or disruptive technologies should be minimized to not only reduce costs, but also to limit the inadvertent development of leakage pathways through new monitoring wells. Where sequestration is associated with EOR operations, it is also important that MMV activities have minimal impact on commercial injection and production operations. MMV activities need to be coordinated and integrated as much as possible with ongoing and planned oil field operations. An emphasis on the collection of reservoir dynamics and monitoring well data (including the use of tracers) in conjunction with routine well operation and maintenance activities can, in some geological settings, be an appropriate and cost-effective strategy for MMV. An emphasis on cost-effectiveness and integration with routine oil field activities was the driving philosophical basis for developing the MMV plan that has been implemented at Zama.

The following techniques have been, and will continue to be, employed to monitor the effects of acid gas injection at the Zama field demonstration site. Monitoring activities are focused on the near-pinnacle environment including caprock integrity, wellbore leakage, and spillpoint breech (Figure 9). The preinjection state of each of these parameters has been determined either by currently available data or field activities to acquire new data:

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

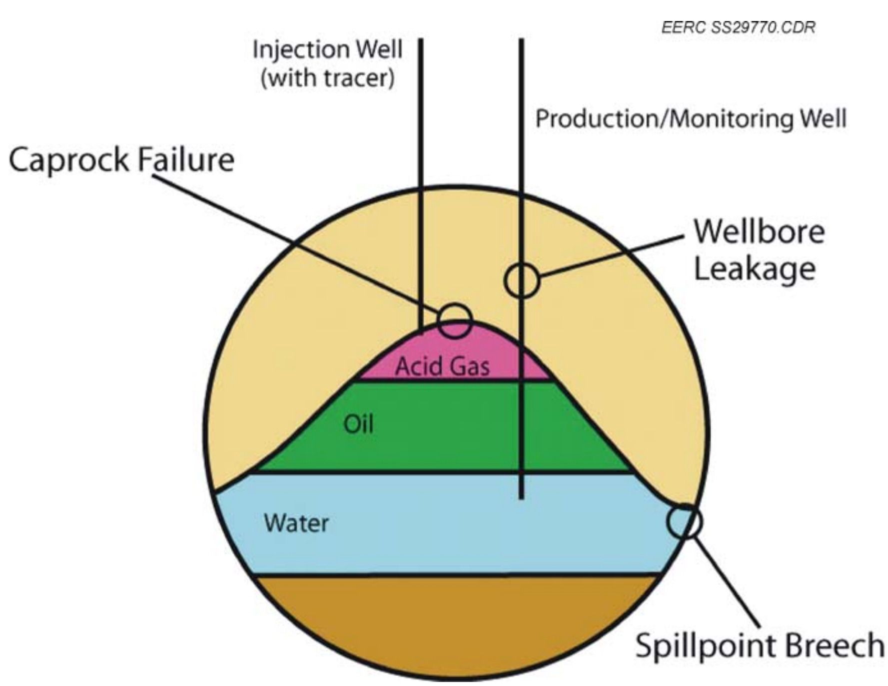

Figure 9. Illustration of the monitoring activities in the near-pinnacle region.

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

3. To monitor CO_2 concentrations and fluxes at the ground surface:
    - Monitoring for tracers (perfluorocarbon)

4. To monitor injection well condition, flow rates, and pressures:
    - Wellhead pressure gauges
    - Well integrity tests
    - Wellbore annulus pressure measurements
    - Surface CO_2 measured near injector points and high-risk areas

5. To monitor solubility and mineral trapping:
    - Formation fluid sampling using wellhead or deep well concentrations of CO_2
    - Major ion chemistry and isotopes

6. To monitor for leakage up faults or fractures:
    - Reservoir and aquifer pressure monitoring

WELLBORE INTEGRITY AND LEAKAGE POTENTIAL

Wellbores constitute a critical element in 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 wellbores; 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 EUB databases. A database of project-specific well data will be constructed from detailed review and synthesis of Apache Canada Ltd. well file information for each pilot well and the immediate wellbores surrounding the pilot. Where possible, cement samples will be taken from old wellbores to evaluate their stability in the long term. 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.

KEY EARLY ACTIVITIES AND RESULTS

While a variety of significant efforts have been conducted by the Zama Acid Gas EOR, CO_2 Sequestration, and Monitoring Project research team, geomechanical evaluations and the collection and analyses of new cores have been the highlights of early activities.

A suite of activities focused on geomechanical characterization have been performed to confirm the mechanical integrity of the reservoir and caprock system. Historical geomechanical analytical work was examined. The historical data sets included wireline logging data which provided information on dynamic elastic properties and stress regimes and analytical data that allowed for the correlation of static-to-dynamic elastic properties and geomechanical simulation. New laboratory tests were also conducted including compression and sonic tests. The compression tests yielded information on strength, static and dynamic elastic properties, compressibility, and stress-dependent permeability. The sonic tests provided data on compressional and shear wave velocities. These data sets are currently in the process of being integrated, correlated, and interpreted and will ultimately form the basis for developing numerical models that will be used to assess the integrity of the reservoir/caprock system.

New core was collected from a well in the vicinity of the F-Pool in March 2007. The new core is approximately 55 feet long and includes portions of the Muskeg Formation (anhydrite caprock) and the Keg River (pinnacle reservoir). This core will be used to evaluate the transition zone from caprock to reservoir rock. Additional core will be collected in 2007 from an area of the Slave Point Formation in the Zama Field that has been exposed to high concentrations of high-pressure acid gas. All cores will be evaluated with respect to geomechanical, geochemical, and mineralogical characteristics. 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 acid gas injection can have on reservoir and caprocks.

Current Injection Activities

Injection of acid gas into the Zama Keg River "F" Pool began December 17, 2006. Rates of injection have been designed to match voidage replacement. To date, there has been no gas or oil production, which indicates that the top-down injection scheme is working effectively and creating the desired oil bank. The current acid gas injection profile is shown in Figure 10. Cumulative injection is over 4000 tons of acid gas, with CO_2 contributing roughly 70% (2800 tons) of this total.

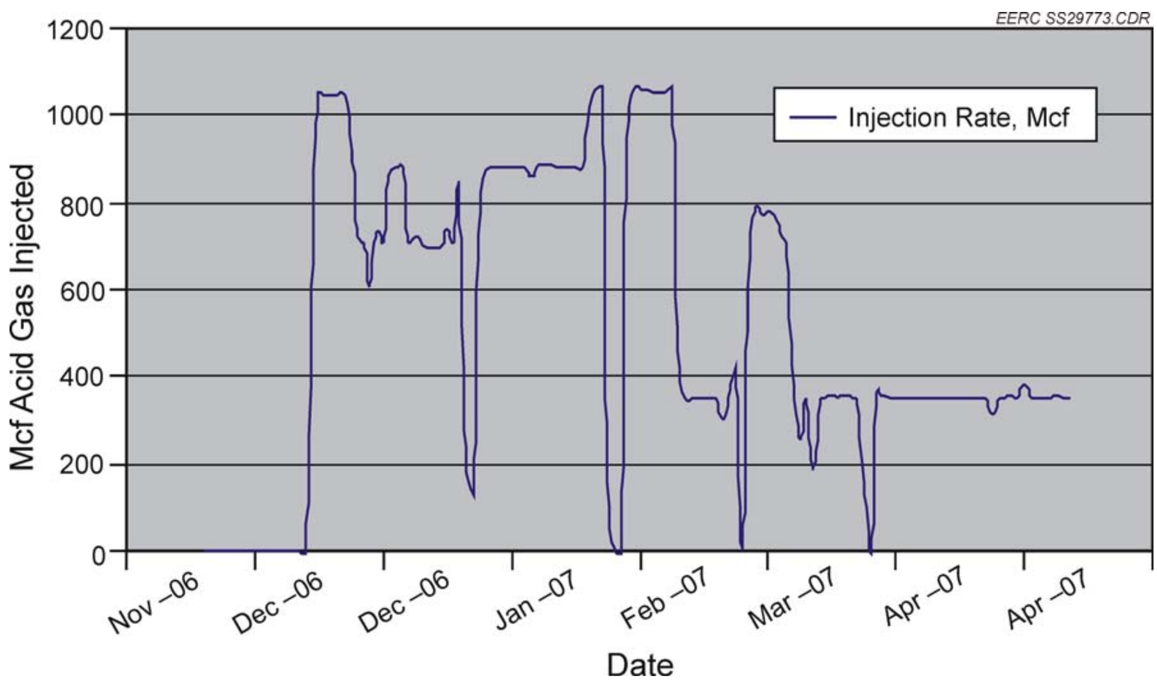

Figure 10. Current acid gas injection profile for the Zama Keg River F pool.

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