EVALUATION OF LARGE-SCALE CARBON DIOXIDE STORAGE POTENTIAL IN THE BASAL SALINE SYSTEM IN THE ALBERTA AND WILLISTON BASINS IN NORTH AMERICA

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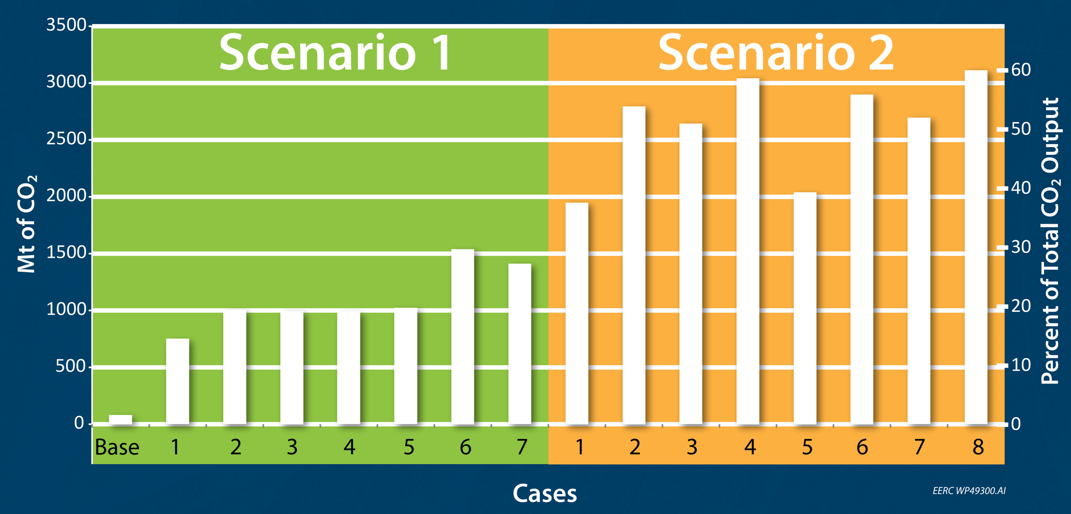
Introduction

A binational effort between the United States and Canada characterized the lowermost saline system in the Williston and Alberta Basins of North America. This project was led on the U.S. side by the Energy & Environmental Research Center (EERC) through the Plains CO_2 Reduction (PCOR) Partnership and on the Canadian side by Alberta Innovates Technology Futures (AITF). This effort was conducted to determine the geologic storage potential of carbon dioxide (CO_2) in rock formations of the 1,340,000 km^2 Cambro–Ordovician saline system (COSS). Characterization of COSS used well log and core data from three states and three provinces to create a heterogeneous 3-D model that was used to determine the effects of CO_2 storage in this system through dynamic simulation. The area underlain by COSS includes several large CO_2 sources that each emits more than 0.9 million tonnes (Mt) CO_2/year. Assuming that each of these sources will target COSS for the storage of its CO_2, the primary questions addressed by this study are 1) what is the CO_2 storage resource of COSS, 2) how many years of current CO_2 emissions will it be capable of storing, and 3) what will be required and what will be the effect of injecting 94 Mt/yr of CO_2 into COSS?

Dynamic Simulation

To evaluate this extensive saline system, and thus its viability as a potential sink, a 3-D geocellular model was used as the framework for an assessment of the dynamic storage capacity of the basal saline system with respect to the large-scale CO_2 sources in the region. Through the dynamic simulation effort, two main objectives were established: 1) assess the dynamic storage capacity of the saline system assuming the 16 aggregated major, large CO_2 sources located above or in close vicinity to this saline system will choose it for CO_2 storage during their respective lifetimes and 2) assess the effect of pressure-related changes induced by the injection of large volumes of CO_2.

Two dynamic injection scenarios, each with multiple cases that varied parameters affecting injection, were investigated. The first scenario positioned injection clusters at the locations of the 16 aggregated CO_2 sources. The second scenario partitioned the sources into 25 accumulation locations that were pipelined to regions with "better" reservoir characteristics (i.e., high permeability of connected volumes) to optimize injection. The varying cases build upon one another in regard to changes, including the vertical to horizontal permeability ratio (Kv/Kh), addition of water extraction wells, relative permeability, rock compressibility, and horizontal injection. All of the dynamic simulations were performed using Computer Modelling Group Ltd.'s (CMG's) software package.



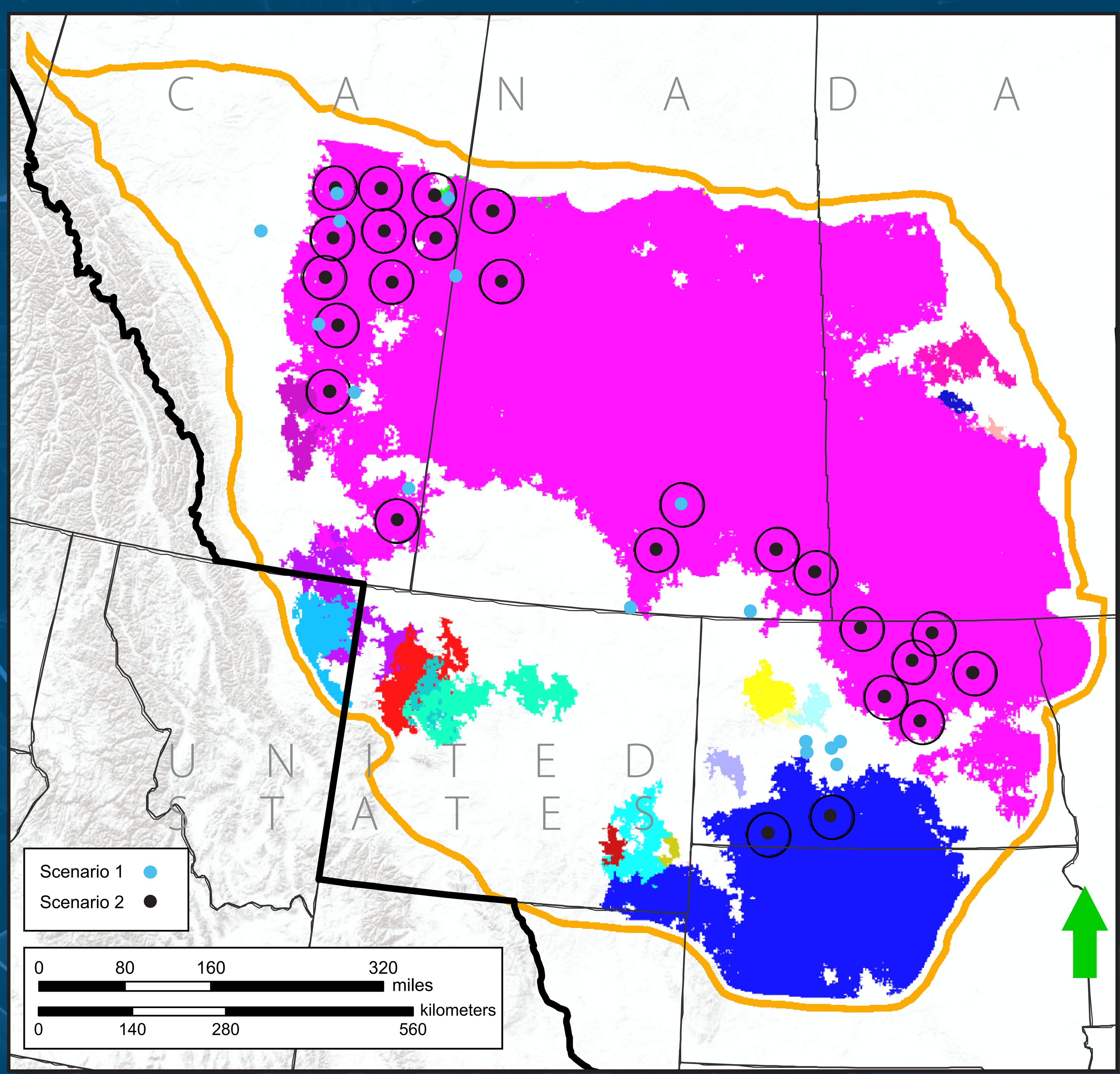
Cases are compared between Scenarios 1 and 2. The best simulation results in this study occurred in Scenario 2, with the inclusion of "better" geology and optimal operations.

Scenario 1				Scenario 2			
Case	Water Extraction	Kv/Kh Ratio	Real Perm. Curves	Case	Water Extraction	Horizontal Injection	Rock Compressibility
Base	No	0.1	No Change	1	No	No	Low
1	No	0.1	No Change	2	No	No	High
2	Yes	0.1	No Change	3	Yes	No	Low
3	Yes	0.4	No Change	4	Yes	No	High
4	Yes	0.6	No Change	5	No	Yes	Low
5	Yes	0.1	Changed	6	No	Yes	High
6	Yes	0.1	Same as Case 5	7	Yes	Yes	Low
7	Yes	0.1	Same as Case 5	8	Yes	Yes	High

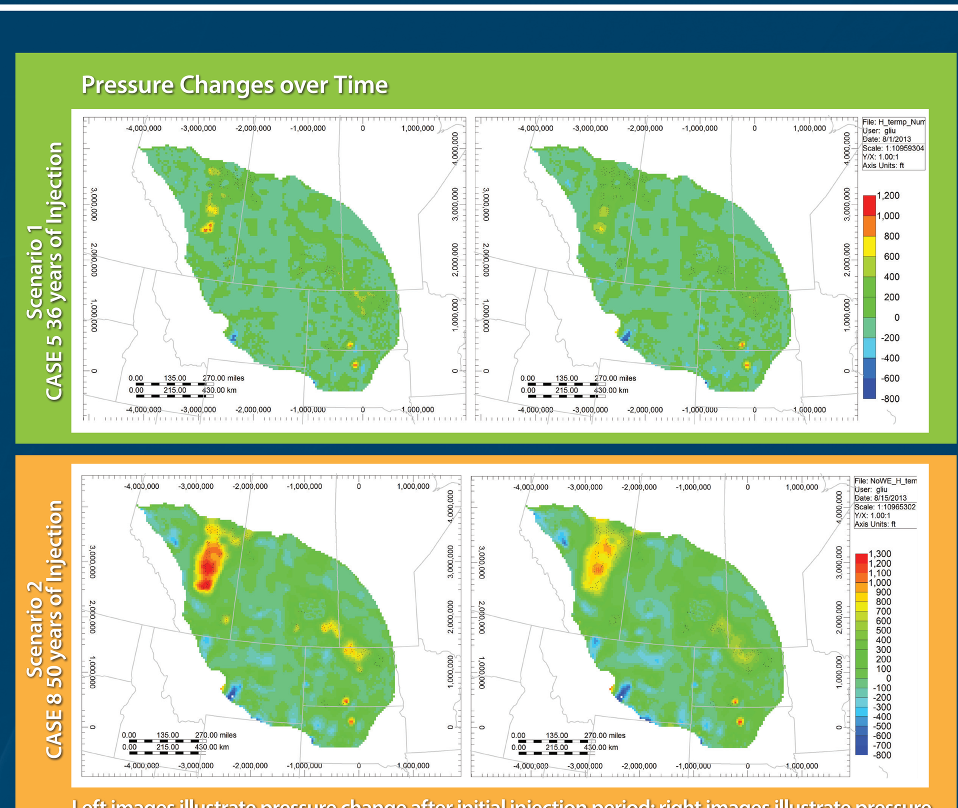
Static CO_2 Storage Resource vs. Dynamic CO_2 Storage Capacity

The static CO_2 storage resource potential was estimated to be approximately 198, 373, and 640 Gt at the P10, P50, and P90 confidence intervals, respectively. With this magnitude of storage potential, COSS should be able to store between 2100 and 6780 years of the current 94 Mt/yr of point source CO_2 emissions from the overlying sources. Thus it should be relatively straightforward to store 94 Mt /yr for 36 or 50 years, resulting in a total storage of 3396 or 4717 Mt, respectively. However, when different cases were investigated to simulate the injection and storage into COSS using wells injecting at a target rate of ~0.45 Mt/yr for 50 years, this total goal was not met. In each case, injectivity was a limiting factor, and in all cases, many more wells would have been required to meet the storage target. The postsimulation analysis reveals that to inject and store 94 Mt /yr of CO_2 for 50 years (4717 Mt) in COSS, a total of 378 to 1050 wells would have been required, instead of the 211 wells that were used in the simulation. This would require dispersing the CO_2 to a greater number of injection areas than the 25 that were simulated.

In a comparison of the total static CO_2 resource value for the 25 injection areas of Scenario 2 to the high- and low-case injection totals in the dynamic simulations, only a relatively small fraction of the total capacity was used. However, it should be noted that this does not imply that the efficiency factors used in this investigation are inaccurate. The dynamic simulations in Scenario 2 were only run for 50 years, and for a majority of the cases, the slope of the injection rate was constant across that time period. The steady injection rate indicates that COSS was still accepting CO_2, and the true dynamic capacity had not yet been reached.



Connected volumes of the basal saline system with a cutoff of permeability greater than 50 mD. Twenty-five injection clusters of Scenario 2 are located in the connected volumes as marked by black circles.



Left images illustrate pressure change after initial injection period; right images illustrate pressure change after a 36-year postinjection period.

Conclusions

Reservoir heterogeneity plays a crucial role in overall CO_2 injection. The basal saline system has ideal characteristics but relies on optimal operations which selected the "better" geologic injection location to sink the total emitted CO_2.

The first injection scenario considered seven cases where the target was to inject this total mass of CO_2 for 36 or 50 years in 16 injection areas using a total of 211 wells. The number of wells is based on an assumed per well injection rate of ~0.45 Mt/yr. The second scenario investigated eight new cases where the original 16 injection locations were disaggregated and moved (pipelined) to areas defined by the model as having good reservoir volume connection (geobodies) based on permeabilities greater than 50 mD.

However, even in the "better" areas, COSS was not able to support 211 injection wells with an average injection rate of 0.45 Mt/yr. In the second scenario, the average annual per well injection rate was between 168,000 and 249,500 Mt/yr. At these injection rates, a total of 378 to 563 wells would have been required to meet the injection target. Pressure differences monitored in the second scenario show small changes in the 50-year injection time period. These minimal pressure differences indicate low risks of leakage from the reservoir and impact to the integrity of the sealing cap rock as a result of CO_2 injection in COSS. Although this broad-scale study should not be used for site-specific interpretation, COSS should be considered as a large-scale, viable target for CO_2 storage across the central interior of North America. The reservoir pressure in all of the cases with water extraction is lower than the cases without water extraction, indicating that water extraction could play a significant role in reservoir management and risk assessment.

PCOR Partnership 2003 – Present

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