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**CO<sub>2</sub> STORAGE  
EFFICIENCY IN DEEP  
SALINE FORMATIONS: A  
COMPARISON OF  
VOLUMETRIC AND  
DYNAMIC STORAGE  
RESOURCE ESTIMATION  
METHODS**

**Report: 2014/09**

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The following paper presents the Overview of the study which has been peer reviewed.



## **CO<sub>2</sub> STORAGE EFFICIENCY IN DEEP SALINE FORMATIONS: A COMPARISON OF VOLUMETRIC AND DYNAMIC STORAGE RESOURCE ESTIMATION METHODS (IEA/CON/13/208)**

### **Key Messages**

- CO<sub>2</sub> storage efficiency starts low, rises quickly, and then levels off in an asymptotic trend to a maximum in much the same way as oil recovery changes in an oil field through time. There is a distinct contrast between an open system, represented by the Minnelusa Formation, and a closed system represented by the Qingshankou and Yaojia Formations. In the Minnelusa Formation it would take 500 years to reach over 50% of the estimated storage capacity whereas this level of capacity could be reached in approximately 50 years in the Qingshankou and Yaojia Formations.
- Care needs to be applied to dynamic storage estimates. The dynamic efficiency method shows that the open aquifer cumulative injection capacity in 50 years is not significantly larger than the closed aquifer one. Consequently, there is a risk that storage capacities could be over-estimated if dynamic conditions are not applied and the properties of ‘open’ and ‘closed’ formations are not taken into account.
- Results from this study clearly show that storage capacity estimates are strongly time-dependent. However, it is important to recognize that a key objective of this study was to determine the maximum storage resource without an arbitrary limited time restriction.
- Additional optimisation operations can be implemented to 1) increase the rate at which storage efficiency increases or 2) increase the maximum storage efficiency.
- The dynamic results become roughly equivalent to the volumetric efficiency values after about 500 years. Volumetric efficiency values could be used if enough time were given for CO<sub>2</sub> to be injected.
- The biggest single factor that increases storage capacity is extraction of formation saline. There are much bigger differences (P10 – P90) in the modelled capacity of an Open system compared with a Closed system.
- Between 15% to 33% of the injected CO<sub>2</sub> could end up in solution in the first 50 years of injection, and this percentage could further increase by up to 16% to 41% after 2,000 years.

### **Background to the study**

The goal of this study was to compare the volumetric and dynamic CO<sub>2</sub> storage resource estimation methodologies used to evaluate the storage potential of deep saline formations (DSFs). This comparison was carried out to investigate the applicability and validity of using volumetric methods, which typically require less data and time to apply, to estimate the CO<sub>2</sub> storage resource potential of a given saline formation or saline system. The project has showed how different variables including saline extraction (pressure management), geological uncertainty, boundary conditions and trapping mechanisms affect storage capacity. Dynamic modelling also revealed how CO<sub>2</sub> storage capacity changes over time.

The project goals were accomplished by applying both volumetric and dynamic CO<sub>2</sub> storage resource estimation methodologies to the open-system upper Minnelusa Formation in the Powder River Basin, of the United States, and a closed-system comprising the Qingshankou and Yaojia Formations in the Songliao Basin, of north-east China. These two saline systems were selected because they are representative examples of an open and a closed system. The



upper Minnelusa Formation consists of aeolian sand dunes cemented and interspersed with carbonates which act as a single flow unit. The Qingshankou and Yaojia Formations consist of deltaic–fluvial deposits, with good storage properties, separated by lacustrine muds with low storage potential. These formations are representative of a linked stacked storage system and were modeled as one system. Both study areas are in intermontane basins; however, the Qingshankou and Yaojia system does not have areas of discharge and recharge while the Minnelusa does. This results in the Minnelusa Formation acting more as an open system, while the Qingshankou and Yaojia system is expected to behave in more of a closed or semiclosed manner. This contrast adds a further dimension and provides a better comparison between the volumetric and dynamic approaches. The volumetric methodology and open-system storage efficiency terms are described in the U.S. Department of Energy (DOE) Carbon Sequestration Atlas of the United States and Canada (U.S. Department of Energy National Energy Technology Laboratory, 2010, Carbon sequestration atlas of the United States and Canada [3rd ed.]) and the closed-system efficiency terms are described by Zhou and others (Zhou, Q., Birkholzer, J.T., Tsang, C.-F., and Rutqvist, J., 2008, A method for quick assessment of CO<sub>2</sub> storage capacity in closed and semiclosed saline formations: *International Journal of Greenhouse Gas Control*, v. 2, no. 4, p. 626–639). Both these terms were used to estimate the effective CO<sub>2</sub> storage resource potential and efficiency in both the upper Minnelusa and Qingshankou–Yaojia systems.

## **Model development**

The dynamic CO<sub>2</sub> storage resource potential and efficiency values were determined through the use of injection simulation. In both the volumetric and dynamic approaches, a geocellular model was constructed of the entire storage formation and the overlying sealing formations. In both the volumetric and dynamic approaches, the same geological model was used so that the assessments could be made on a consistent basis. For each system, the effective open-system and closed-system storage efficiency terms were calculated so they could be compared to the storage efficiency as determined using the dynamic approach.

Storage efficiency is defined as the estimated storage capacity, determined by dynamic modelling, expressed as a percentage of the theoretical storage resource. The theoretical storage resource represents the absolute total pore volume within a rock formation. In this study the theoretical resource limit only considers the formation properties that make it amenable to CO<sub>2</sub> storage, e.g., good porosity and permeability. The starting point for both approaches was the construction of a geocellular model. Background data was compiled on the selected formations from each basin. Data was retrieved from existing structure contour maps, isopach maps, facies maps, geophysical wellbore logs, core analysis data and general geological interpretation. Petrophysical analysis was then used to determine porosity and permeability properties which could be used to develop facies models that could then be used to determine CO<sub>2</sub> storage potential. The final step is to scale up the facies models within the formation across the entire basin. The procedure is summarised in Figure 1.

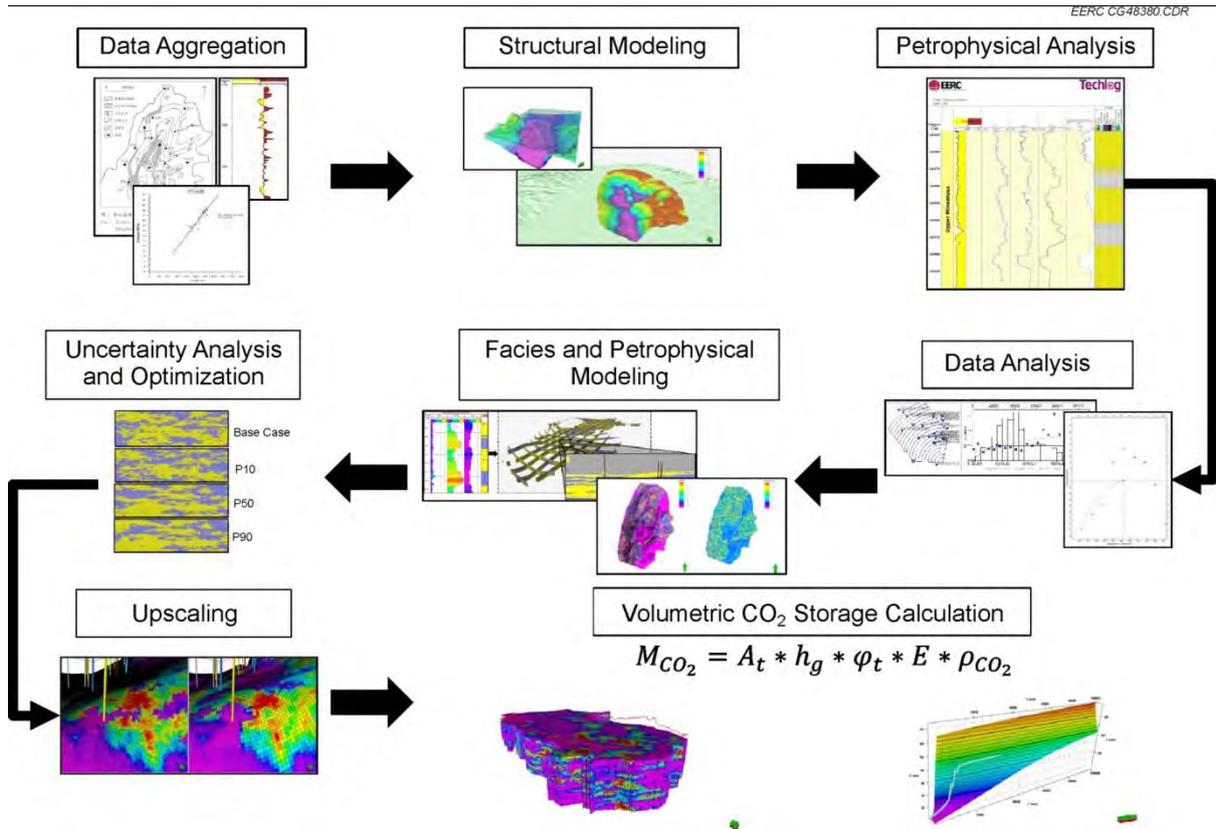


Figure 1 Workflow for the construction of geocellular models to calculate the effective storage resource potential.

Uncertainty analysis and reservoir optimization was also applied to the base line for the models. The high case for each example was a 90th percentile (P90) condition and contains more of the primary storage facies and more pore volume, while the low case was a 10th percentile (P10) condition which has less primary storage facies and less total pore volume. The mid case is represented by a 50th percentile (P50) and is similar to the base case condition. A further refinement was applied in this case by applying boundary conditions which determined the extent of suitable reservoir conditions determined by porosity and permeability thresholds (<5 mD in the Qingshakou–Yaojia system and <1 mD in the Minnelusa Formation). The geocellular model was comprised of interconnected cells which consisted of storage facies above these predetermined thresholds. The procedure is outlined in Figure 2.

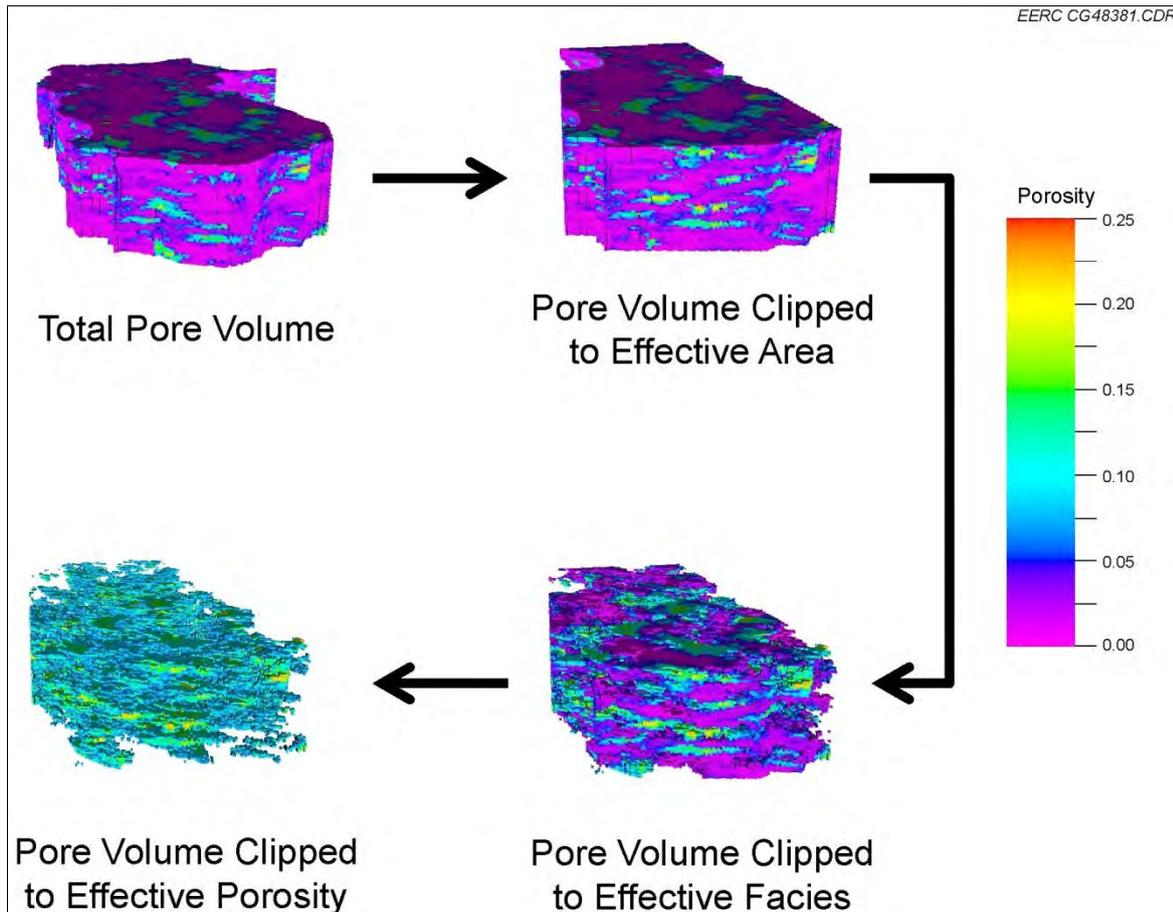


Figure 2. Sequential reduction in total pore volume to the effective pore volume in the upper Minnelusa Formation (the model is shown in Simbox (i.e., all of the cells have the same size and the thickness))

The study also explored how boundary conditions might affect storage capacity. The dynamic models were run for both the upper Minnelusa and Qingshankou–Yaojia systems with modifications to the peripheral cells in the geocellular model to simulate “open” and “closed” conditions”. The “actual” boundary conditions were defined by constructing the geocellular model to cover the entire formational extent, including areas too shallow to inject CO<sub>2</sub>; areas of discharge, recharge, and outcrops; and all of the overlying sealing formations to the surface. The overlying seals were assigned realistic porosity, permeability, and relative permeability values based on these formation types found in the literature. Constant pressure boundaries were then assigned to the surface, as well as recharge, discharge, and outcrop areas. The lateral edges of the formations were assigned no-flow boundaries. The inclusion of these additional areas outside of those typically considered for injection in the model made it possible to assess whether the systems are open, closed, or semiclosed. The “open” boundary conditions were defined by taking the same model conditions described in the actual boundary conditions and adding infinite acting boundary conditions to all lateral edges of the formation—including those terminating deep in the subsurface and those that would otherwise be closed because of sealing faults or other features. “Closed” boundaries were assigned the same conditions as the actual boundary conditions except for reducing the permeability to the overlying formations by a factor of 100. If the permeability in the overlying seals is already in the nanodarcy range, the results will not look significantly different than the actual boundary conditions scenario, with both acting as closed systems



## Model simulation results

The results of the model simulations for both systems are presented in Figure 3 which clearly shows a distinct contrast between the two systems. In the case of the upper Minnelusa Formation the results show a divergence of between an efficiency of 18% for an “open case” and 7.2% for a “closed” case after 2,000 years. In addition, the permeability of the overlying seals in the actual and open boundary conditions cases increased the storage efficiency in the actual and open scenarios by 53% and 147%, respectively, illustrating the important role that the formation seals can play in influencing storage efficiency, even in open systems. By contrast, changing the boundary conditions of the Qingshankou–Yaojia cases did little to affect the resulting storage efficiency after 50 and 2,000 years. After 50 years of injection, the Qingshankou–Yaojia system’s boundary condition cases had effective storage efficiencies ranging from 0.34% to 0.37%. After 2,000 years, these had increased but still did not vary significantly, with a resulting range of 0.62% to 0.67%. This is probably due to the very low permeability at the lateral edges and overlying seals in the actual boundary condition.

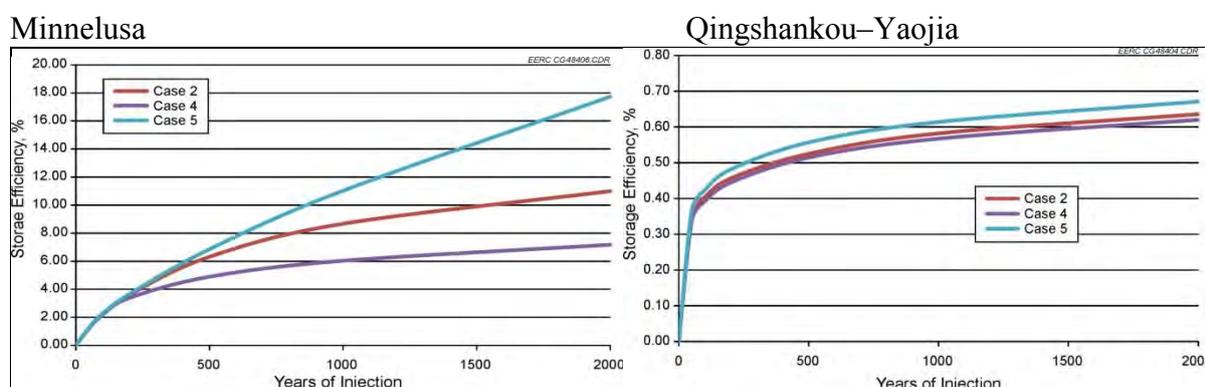


Figure 3 The Dynamic effective CO<sub>2</sub> storage efficiency over time for the actual, open, and closed boundary conditions cases in the Minnelusa and Qingshankou–Yaojia systems

A total of twelve simulation cases were run for both the upper Minnelusa and Qingshankou–Yaojia models to investigate the effects of trapping mechanisms, geologic uncertainty, boundary conditions, well configuration, and injection and extraction strategies. In each simulation run, the entire formation extent and overlying formations were included within the models in order to better understand the pressure buildup effects. Initially, injection was simulated for 50 years, and then the maximum dynamic storage was estimated by running a few cases with continuous injection for up to two thousand years until the maximum storage potential was reached. Based on the results of these simulations, the upper Minnelusa Formation behaved as an open system with dynamic CO<sub>2</sub> storage efficiency ranging between 0.55% to 1.7% after 50 years, 2.5% to 7.9% after 500 years, and 3.4% to 18% after 2,000 years of continuous injection in cases without water extraction (see Table 1).

	Low	High
Volumetric Efficiency – Closed System	0.54%	0.54%
Volumetric Efficiency – Open System	2.9%	11%
Dynamic Efficiency – 50 years’ Injection	0.55%	1.7%
Dynamic Efficiency – 200 years’ Injection	1.9%	4.3%
Dynamic Efficiency – 500 years’ Injection	2.5%	7.9%
Dynamic Efficiency – 2000 years’ Injection	3.4%	18%



These results are in very close agreement with the calculated effective volumetric CO<sub>2</sub> storage efficiency and indicate that the use of a volumetric methodology would be applicable in formations that behave in a truly open manner as long as enough time is given for the CO<sub>2</sub> to be injected. However, in the first 50 years of injection, these results are on the low side of the volumetric CO<sub>2</sub> storage resource potential, which could have implications for published CO<sub>2</sub> storage estimates made with volumetric methods. It should be stressed that in the Minnelusa system (for Cases 2, 6 and 12) between 7% and 12% of the total maximum capacity is stored in the first 50 years. For each of these cases it would take 500 years to store over 50% of the estimated capacity (Table 2).

Time years	Case 2* - Mt	%	Case 6** - Mt	%	Case 12*** - Mt	%
0						
50	1,672	11%	742	7%	2,263	12%
100	2,928	20%	1,504	14%	3,698	20%
200	4,830	33%	2,838	26%	5,826	32%
500	8,491	57%	5,830	54%	10,558	58%
1,000	11,662	79%	8,417	77%	14,363	79%
2,000	14,786	100%	10,867	100%	18,168	100%

\*Case 2 P50 Actual Boundary Conditions (Base case)

\*\*Case 6 P50 half the number of vertical injectors

\*\*\*Case 12 P50 Double the number of vertical injectors

In the case of the Qingshankou–Yaojia system, the dynamic approach resulted in the storage efficiency ranging between 0.28% to 0.40% after 50 years, 0.45% to 0.60% after 500 years, and 0.62% to 0.72% after 2,000 years of continuous injection in cases without water extraction (see Table 3). These results are in very close agreement with the calculated closed system efficiency values and indicate that the system is closed or semiclosed. This approach supports the use of a volumetric estimate for similar systems, as long as a closed-system storage efficiency is applied.

	Low	High
Volumetric Efficiency – Closed System	0.21%	0.21%
Volumetric Efficiency – Open System	1.3%	10%
Dynamic Efficiency – 50 years' Injection	0.28%	0.40%
Dynamic Efficiency – 200 years' Injection	0.39%	0.52%
Dynamic Efficiency – 500 years' Injection	0.45%	0.60%
Dynamic Efficiency – 2000 years' Injection	0.62%	0.72%

In contrast to the Minnelusa Formation the Qingshankou–Yaojia system would attain over 50% of its potential storage capacity within 50 years but the rate of storage would decline significantly after about 300 years (see Table 4 and Figure 3). The difference between these two modelled formations is attributed to the contrast in depositional environments and associated variation in facies within each formation.



Time years	Case 2* - Mt	%	Case 6** - Mt	%	Case 12*** - Mt	%
0						
50	3,066	55%	2,448	52%	3,312	58%
100	3,547	64%	3,010	64%	3,772	66%
200	4,005	72%	3,459	73%	4,220	74%
500	4,605	83%	3,936	84%	4,803	84%
1,000	5,107	92%	4,305	91%	5,266	92%
2,000	5,578	100%	4,711	100%	5,713	100%

\*Case 2 P50 Actual Boundary Conditions (Base case)

\*\*Case 6 P50 half the number of vertical injectors

\*\*\*Case 12 P50 Double the number of vertical injectors

The volumetric methodology was applied to the two systems, using both the open-system and closed-system efficiencies. This resulted in open-system effective CO<sub>2</sub> storage efficiency in the upper Minnelusa Formation from 2.9% to 11% and the closed-system effective CO<sub>2</sub> storage efficiency of 0.54%. In the Qingshankou–Yaojia system, the open-system efficiency was 1.3% to 10%, and the closed-system efficiency was 0.21%. This wide range in effective storage efficiency values is due to the large amount of uncertainty in both the geological properties and the flow properties of the system.

This study also investigated the effects of geological uncertainty, boundary conditions, the number and types of wells used, and water extraction techniques on the effective CO<sub>2</sub> storage efficiency. In both the open-system upper Minnelusa and closed-system Qingshankou–Yaojia system, the use of water extraction had the largest effect on CO<sub>2</sub> storage potential, increasing the storage efficiency by as much as 475% in the Qingshankou–Yaojia system and by approximately 100% in the upper Minnelusa Formation after 50 years of operation. The extraction rate and therefore the estimated level of increased storage efficiency compared with a volumetric base case depends not only on the numbers of injection and extraction wells but also if they are horizontal or vertical.

The study did not specifically examine the cost-effectiveness of different wells but it did compare the technical merits of well orientation. The study compared the effects on capacity assuming different combinations of vertical and horizontal injectors and extraction wells. The study included a comparison of an equal number of vertical and horizontal wells, and a volumetric capacity assuming a P50 condition, for both the Minnelusa and the Qingshankou-Yaojia formations. In the Minnelusa, there is 2% change from Case 2 (base case after 50 years). In the Qingshankou-Yaojia, there was a 3% change from the base case. If this is accurate, the horizontal wells provide no significant benefit over the vertical wells from a capacity standpoint, and they are certainly more expensive. In North America, horizontal wells may be 2-3 times more expensive per well than a vertical well. In the study the horizontals did not provide that much benefit even after 2,000 years, although they might have contributed 20% more capacity. On a site specific case, the use of horizontal wells may be a good option, however it will depend on a number of site specific variables.



Other factors including geological uncertainty and boundary conditions as well as the number and type of wells, did not play as significant a role in increasing the storage efficiency, as local pressure buildup and the concomitant reduction in the rate of injection in the upper Minnelusa Formation. Modelling results showed that regional pressure buildup was by far the biggest limiting factor in the Qingshankou–Yaojia system.

In open-system cases such as the Minnelusa Formation (see Figure 3), the dynamic CO<sub>2</sub> storage resource potential is time-dependent, and it asymptotically approaches the volumetric CO<sub>2</sub> storage resource potential over very long periods of time in the order of several hundred or thousands of years. This is very similar to resource industries, namely, mining and the oil and gas industries, where if CO<sub>2</sub> is treated in an equivalent manner to a resource its maximum storage potential can only be fully realized by using advanced technology, notwithstanding time, economics, regulatory, and other considerations. In closed systems, the maximum efficiency is reached much more quickly, and the results are roughly equivalent to the volumetric results calculated using a closed-system storage efficiency term. These results indicate that the volumetric assessments can be used as long as an open- or closed-system efficiency term is applied appropriately, with the understanding that the effective CO<sub>2</sub> storage efficiency of a formation will probably take hundreds of wells spaced throughout a formation's area, and it could take decades or possibly thousands of years of injection to fully realize the effective CO<sub>2</sub> storage resource potential.

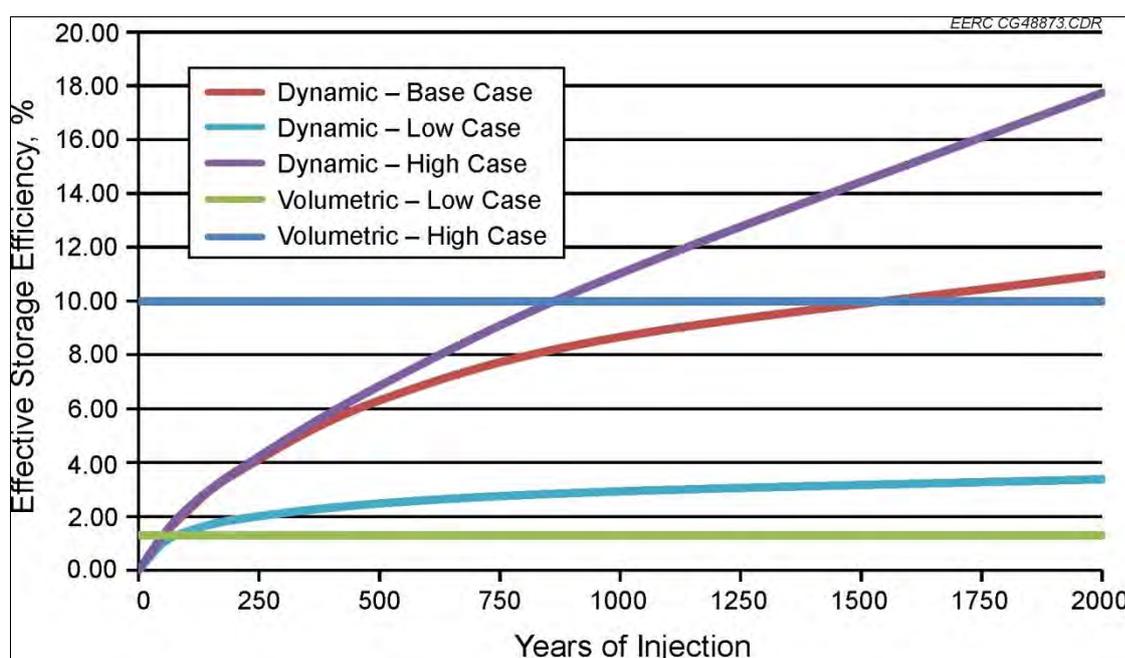


Figure 3. The dynamic CO<sub>2</sub> storage efficiency of open systems is very time-dependent and slowly reaches an asymptote over time which approaches the volumetric effective CO<sub>2</sub> storage efficiency, as shown here with the open-system Minnelusa Formation

Trapping mechanisms are likely to play different roles in storing CO<sub>2</sub> in a formation throughout the life of the storage project. In this study, the main concern was how these trapping mechanisms affect the effective CO<sub>2</sub> storage efficiency. Residual trapping occurs in a two part process, firstly CO<sub>2</sub> displaces the formation fluid and later, generally after the injection stops, the formation fluid (usually brine) imbibes back in and traps a portion of the CO<sub>2</sub> in the pore



spaces. Solubility trapping occurs throughout the injection stage and then continues post injection. CO<sub>2</sub> solubility is a function of temperature, pressure, salinity, and the rate of mixing between the CO<sub>2</sub> and undersaturated formation water.

A series of simulations were run to determine the relative effects of physical, hydrodynamic, residual gas, and solubility trapping on the effective CO<sub>2</sub> storage efficiency of each formation. Over time, the trapping mechanisms lock CO<sub>2</sub> in the reservoir and gradually decrease the amount of remaining storage potential. This principle holds true for all of the mechanisms except solubility trapping. As injected CO<sub>2</sub> mixes with the native formation waters, a portion of the CO<sub>2</sub> dissolves, taking up less space in the reservoir which increases the storage efficiency by decreasing formation pressure and allowing more CO<sub>2</sub> to be stored in the same pore volume.

In this study it was assumed that injection was continuous and that solubility trapping was a major component of the storage capacity during injection. In both cases (Minnelusa Formation and Qingshankou-Yaojia Formations) about 20%-30% of the storage was as dissolved CO<sub>2</sub> (solubility trapping) after 50 years and increased in percentage as more time passed in the case of the Qingshankou-Yaojia Formations, as convective mixing increased the trapping processes (Table 5). The difference in the predicted percentage of solubility trapped CO<sub>2</sub> between the Minnelusa and the Qingshankou-Yaojia Formations could be attributed to the contrast in brine salinity. It should be stressed that the potential accuracy of the model to estimate solubility trapping depends on the size of its cells. Because of the basin-wide scale of the model large cell sizes were used study. To simulate the mixing process more accurately fine grids are needed which was beyond the scope of this study.

The salinity from each formation was based on published values. The average in the usable pore volume of each case was 242,000 ppm in the Minnelusa and 20,000 ppm in the Qingshankou-Yaojia. As previously stated the difference in salinity concentration may account for the higher percentage of dissolved CO<sub>2</sub> in the Qingshankou-Yaojia formations. The solubility of CO<sub>2</sub> is lower in formations with higher salinities and temperatures

<b>Table 5 Comparison in CO<sub>2</sub> solubility between the Minnelusa and Qingshankou-Yaojia Formations</b>									
Minnelusa Formation									
Comparison of CO <sub>2</sub> in solution compared with Total CO <sub>2</sub> injected after 50 and 500 years injection									
Time	Case 2			Case 6			Case 12		
	total Injected	Mass CO <sub>2</sub> in solution		total Injected	Mass CO <sub>2</sub> in soln		total Injected	Mass CO <sub>2</sub> in solution	
50	1,674	348	21%	742	116	16%	2,263	515	23%
500	8,491	2,000	24%	5,830	1,000	17%	10,558	2,400	23%
Qingshankou-Yaojia Formations									
Comparison of CO <sub>2</sub> in solution compared with Total CO <sub>2</sub> injected after 50 and 500 years injection									
Time	Case 2			Case 6			Case 12		
50	3,067	845	28%	2,578	524	20%	3,312	1,080	33%
500	4,605	1,750	38%	3,936	1,100	28%	4,803	1,870	39%

It would be very difficult to determine how much CO<sub>2</sub> is trapped residually after injection stops without running further simulations. Solubility trapping will continue after injection stops as convective mixing continues. Additional simulations could be run for a fixed period of time



(50 years) post injection and then continued for several thousand years more to see what percent of free CO<sub>2</sub> becomes residually trapped CO<sub>2</sub>, solubility trapped CO<sub>2</sub>, and mineral trapped CO<sub>2</sub> (mineral trapping was ignored in this study). It cannot be assumed that the residual CO<sub>2</sub> trapped will be equal to the amount that remains after the solubility stops. There will be areas that will have free phase CO<sub>2</sub> that are trapped in structures and stratigraphic traps, there will be CO<sub>2</sub> that is mineral trapped and solubility trapping will continue for a very long period of time in a scenario like this as the CO<sub>2</sub> is spread out widely in the formation.

### **Expert Review Comments**

This study was reviewed by five experts. There was a general consensus that the study has been well-conceived, well-executed, well-written, well organized, and carefully compiled. There were some specific points raised including the selection of the 10,000 TDS threshold as an upper limit for formation water which should be excluded from CO<sub>2</sub> injection. (This threshold is the US definition of formation water that can be used as a source of potable water). The clear explanation of parameters used in models particularly the criteria for porosity cut-off and an explanation of model limitations including the pressure threshold used in models (20% > initial reservoir pressure) were added to the report. Other minor modifications included the clarification of units and footnotes in tables and the inclusion of well densities. The experts proposed the inclusion of key messages specifically analogies with extractive industries like oil and gas. CO<sub>2</sub> storage is a constrained resource comparable to oil and gas production.

### **Conclusions**

The dynamic CO<sub>2</sub> storage resource potential and efficiency was determined through the use of reservoir simulation. In both the volumetric and dynamic approaches, a geocellular model was constructed of the entire storage formations and the overlying sealing formations all the way to the surface. The same geological model was used so that the assessments made could be compared on a consistent basis. For the purposes of this study, three DSFs were selected in two different geographic regions, with different geological conditions, to try to determine the validity of the volumetric estimates and the level of agreement between the volumetric and dynamic approaches.

The simulation results for the upper Minnelusa Formation shows that it behaves in an open fashion, with dynamic CO<sub>2</sub> storage efficiency ranging from 0.55% to 1.7% after 50 years, 2.5% to 7.9% after 500 years, and 3.4% to 18% after 2,000 years of continuous injection in cases without water extraction. The dynamic results become roughly equivalent to the volumetric efficiency values after about 500 years, indicating that the volumetric efficiency values could be used if enough time were given for CO<sub>2</sub> to be injected. However, analysis of three case studies indicates that between 7% and 12% of the total estimated capacity is stored within 50 years and it would take 500 years to reach over 50% capacity. In contrast the Qingshankou–Yaojia system reaches over 50% capacity in 50 years but the rate of storage would decline significantly after about 300 years.

In the Qingshankou–Yaojia system, the dynamic efficiency varied from 0.28% to 0.40% after 50 years, 0.45% to 0.60% after 500 years, and 0.62% to 0.72% after 2,000 years of continuous injection in cases without water extraction. These results are in close agreement with the calculated closed-system efficiency values and indicate that the system is closed or semiclosed.



This supports the use of a volumetric approach for similar systems, as long as closed-system storage efficiency values are applied.

In the open-system upper Minnelusa Formation, geologic uncertainty and heterogeneity and the use of water extraction had the biggest effect on the effective CO<sub>2</sub> storage efficiency. The number and type of wells did not play such an important role, especially in the long-injection scenarios. In the closed Qingshankou–Yaojia system, the use of water extraction increased the storage efficiency by as much as 475% during a 50-year injection scenario. The other factors did not play much of a role in increasing the storage efficiency, as pressure buildup in the formation was by far the biggest limiting factor on the effective CO<sub>2</sub> storage efficiency.

In open-system cases, the dynamic CO<sub>2</sub> storage resource potential is time-dependent, and it asymptotically approaches the volumetric CO<sub>2</sub> storage resource potential over very long periods of time. This is very similar to other resource industries, namely, mining and the oil and gas industries. In closed systems, the maximum efficiency is reached much more quickly, and the results are roughly equivalent to the volumetric results calculated using a closed-system storage efficiency term. These results indicate that the volumetric assessments can be used as long as an open- or closed-system efficiency term is applied appropriately, with the understanding that the effective CO<sub>2</sub> storage efficiency of a formation is likely take hundreds of wells spaced throughout a formation's area. It is likely that it could take decades or, possibly, thousands of years of injection to fully realize the effective CO<sub>2</sub> storage resource potential.

## **Recommendations**

The results from this study are illustrative and only represent two contrasting depositional environments. It may be worthwhile to investigate additional formations to determine whether the results from this study compare with a wider cross section of geological conditions and depositional environments. Solubility trapping may also need to be investigated more in the future, as it may play an important role in the geological storage of CO<sub>2</sub>. One of the limitations of this study is the size of the cells used in the geocellular models. Models with a larger number of cells that model formations over the same areas should enhance the predictive results. However, there is a compromise between the modelling objectives and the sophistication and computational resources required to run a series of different cases. There are also concerns in this study as to whether or not the physics of the solubility trapping process are adequately captured by the grid dimensions and cell sizes used in this study.

# **CO<sub>2</sub> STORAGE EFFICIENCY IN DEEP SALINE FORMATIONS: A COMPARISON OF VOLUMETRIC AND DYNAMIC STORAGE RESOURCE ESTIMATION METHODS (IEA/CON/13/208)**

Revised Final Report

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**ABSTRACT**

As the field of carbon capture and storage (CCS) continues to advance, and large-scale implementation of geologic carbon dioxide (CO<sub>2</sub>) storage progresses, it will be important to understand the potential of geologic formations to store meaningful amounts of CO<sub>2</sub>. Geologic CO<sub>2</sub> storage in deep saline formations (DSFs) has been suggested as one of the best potential methods for reducing anthropogenic CO<sub>2</sub> emission to the atmosphere, and as such, updated storage resource estimation methods will continue to be an important component for the widespread deployment of CCS around the world. While there have been several methodologies suggested in the literature, most of these methods are based on a volumetric calculation of the pore volume of the DSF multiplied by a storage efficiency term and do not consider the effect of site-specific dynamic factors such as injection rate, injection pattern, timing of injection, pressure interference between injection locations, and overall formation pressure buildup. These volumetric methods may be excellent for comparing the potential between particular formations or basins, but they have not been validated through real-world experience or full-formation injection simulations. Several studies have also suggested that the dynamic components of geologic storage may play the most important role in storing CO<sub>2</sub> in DSFs but until now have not directly compared CO<sub>2</sub> storage resource estimates made with volumetric methodologies to estimates made using dynamic CO<sub>2</sub> storage methodologies. In this study, two DSFs, in geographically separate areas with geologically diverse properties, were evaluated with both volumetric and dynamic CO<sub>2</sub> storage resource estimation methodologies to compare the results and determine the applicability of both approaches.

In the end, it was determined that the dynamic CO<sub>2</sub> storage resource potential is time-dependent and it asymptotically approaches the volumetric CO<sub>2</sub> storage resource potential over very long periods of time in the two systems that were evaluated. These results indicate that the volumetric assessments can be used as long as the appropriate storage efficiency terms are used and it is understood that it will take many wells over very long periods of time to fully realize the storage potential of a target formation.

This subtask was funded through the Energy & Environmental Research Center (EERC)–U.S. Department of Energy (DOE) Joint Program on Research and Development for Fossil Energy-Related Resources Cooperative Agreement No. DE-FC26-08NT43291. Nonfederal funding was provided by the IEA Greenhouse Gas R&D Programme.

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## **EXECUTIVE SUMMARY**

The goal of this study was to compare the volumetric and dynamic CO<sub>2</sub> storage resource estimation methodologies used to evaluate the storage potential of deep saline formations (DSFs). This comparison was carried out to investigate the applicability of using volumetric methods, which typically require less data and time to apply, to estimate the CO<sub>2</sub> storage resource potential of a given saline formation or saline system. The project goals were accomplished by applying both the volumetric and dynamic CO<sub>2</sub> storage resource estimation methodologies to the open-system upper Minnelusa Formation in the Powder River Basin, United States, and a closed-system comprising the Qingshankou and Yaojia Formations in the Songliao Basin, China. These two saline systems were selected since they represent an open and a closed system, allowing for a better comparison of the volumetric and dynamic approaches. The volumetric methodology and open-system storage efficiency terms described in the U.S. Department of Energy (DOE) Carbon Sequestration Atlas of the United States and Canada (U.S. Department of Energy National Energy Technology Laboratory, 2010, Carbon sequestration atlas of the United States and Canada [3rd ed.]) and the closed-system efficiency term described by Zhou and others (Zhou, Q., Birkholzer, J.T., Tsang, C.-F., and Rutqvist, J., 2008, A method for quick assessment of CO<sub>2</sub> storage capacity in closed and semiclosed saline formations: *International Journal of Greenhouse Gas Control*, v. 2, no. 4, p. 626–639) were used to estimate the effective CO<sub>2</sub> storage resource potential and efficiency in both the upper Minnelusa and Qingshankou–Yaojia systems.

The dynamic CO<sub>2</sub> storage resource potential and efficiency values were determined through the use of reservoir simulation. In both the volumetric and dynamic approaches, a geocellular model was constructed of the entire storage formation and the overlying sealing formations. In both the volumetric and dynamic approaches, the same geologic model was used so that the assessments made could be compared on a consistent basis. For each system, the effective open-system and closed-system storage efficiency terms were calculated so they could be compared to the storage efficiency as determined using the dynamic approach. The volumetric methodology was applied to the two systems, using both the open-system and closed-system efficiencies. This resulted in open-system effective CO<sub>2</sub> storage efficiency in the upper Minnelusa Formation from 2.9% to 11% and the closed-system effective CO<sub>2</sub> storage efficiency of 0.54%. In the Qingshankou–Yaojia system, the open-system efficiency was 1.3% to 10%, and the closed-system efficiency was 0.21%. This wide range in effective storage efficiency values is due to the large amount of uncertainty in both the geologic properties and the flow properties of the system.

As a means of testing whether or not these two storage systems are open, closed, or semiclosed, dynamic reservoir simulations were performed on each model. A total of twelve simulation cases were run for both the upper Minnelusa and Qingshankou–Yaojia models to investigate the effects of trapping mechanisms, geologic uncertainty, boundary conditions, well configuration, and injection and extraction strategies. In each simulation run, the entire formation extent and overlying formations were included within the models in order to better understand the

pressure buildup effects. Initially, injection was simulated for 50 years, and then the maximum dynamic storage was estimated by running a few cases with continuous injection for hundreds or thousands of years until the maximum storage potential was reached. Based on the results of these simulations, the upper Minnelusa Formation behaved as an open system with dynamic CO<sub>2</sub> storage efficiency ranging between 0.55% to 1.7% after 50 years, 2.5% to 7.9% after 500 years, and 3.4% to 18% after 2000 years of continuous injection in cases without water extraction. These results are in very close agreement with the calculated effective volumetric CO<sub>2</sub> storage efficiency and indicate that the use of a volumetric methodology would be applicable in formations that behave in a truly open manner as long as enough time is given for the CO<sub>2</sub> to be injected (Table ES-1). However, in the first 50 years of injection, these results are on the low side of the volumetric CO<sub>2</sub> storage resource potential, which could have implications for published CO<sub>2</sub> storage estimates made with volumetric methods. In the case of the Qingshankou–Yaojia system, the dynamic approach resulted in storage efficiency ranging between 0.28% to 0.40% after 50 years, 0.45% to 0.60% after 500 years, and 0.62% to 0.72% after 2000 years of continuous injection in cases without water extraction. These results are in very close agreement with the calculated closed system efficiency values and indicate that the system is closed or semiclosed (Table ES-2). This supports the use of a volumetric approach for similar systems, as long as a closed-system storage efficiency is applied.

This study also investigated the effects of geologic uncertainty, boundary conditions, the number and types of wells used, and water extraction techniques on the effective CO<sub>2</sub> storage efficiency. In both the open-system upper Minnelusa and closed-system Qingshankou–Yaojia system, the use of water extraction had the largest effect on CO<sub>2</sub> storage potential, increasing the storage efficiency by as much as 475% in the Qingshankou–Yaojia system and by approximately 100% in the upper Minnelusa Formation after 50 years of operation. The other factors did not play as significant a role in increasing the storage efficiency, as local pressure buildup reduced the rate of injection in the upper Minnelusa Formation and regional pressure buildup was by far the limiting factor in the Qingshankou–Yaojia system.

In open-system cases, the dynamic CO<sub>2</sub> storage resource potential is time-dependent, and it asymptotically approaches the volumetric CO<sub>2</sub> storage resource potential over very long periods of time (Figure ES-1). This is very similar to other resource industries, namely, mining and the oil and gas industries, where CO<sub>2</sub> is a resource that can only be fully realized if it is exploited to its maximum using advanced technology, notwithstanding time, economics, regulatory, and other considerations. In closed systems, the maximum efficiency is reached much more quickly, and the results are roughly equivalent to the volumetric results calculated using a closed-system storage efficiency term. These results indicate that the volumetric assessments can be used as long as an open- or closed-system efficiency term is applied appropriately, with the understanding that the effective CO<sub>2</sub> storage efficiency of a formation will likely take hundreds of wells spaced throughout a formation's area, and it would likely take decades or possibly thousands of years of injection to fully realize the effective CO<sub>2</sub> storage resource potential.

**Table ES-1. Minnelusa System Effective CO<sub>2</sub> Storage Efficiency**

	Low	High
Volumetric Efficiency – Closed System	0.54%	0.54%
Volumetric Efficiency – Open System	2.9%	11%
Dynamic Efficiency – 50 years’ Injection	0.55%	1.7%
Dynamic Efficiency – 200 years’ Injection	1.9%	4.3%
Dynamic Efficiency – 500 years’ Injection	2.5%	7.9%
Dynamic Efficiency – 2000 years’ Injection	3.4%	

**Table ES-2. Qingshankou–Yaojia System Effective CO<sub>2</sub> Storage Efficiency**

	Low	High
Volumetric Efficiency – Closed System	0.21%	0.21%
Volumetric Efficiency – Open System	1.3%	10%
Dynamic Efficiency – 50 years’ Injection	0.28%	0.40%
Dynamic Efficiency – 200 years’ Injection	0.39%	0.52%
Dynamic Efficiency – 500 years’ Injection	0.45%	0.60%
Dynamic Efficiency – 2000 years’ Injection	0.62%	0.72%

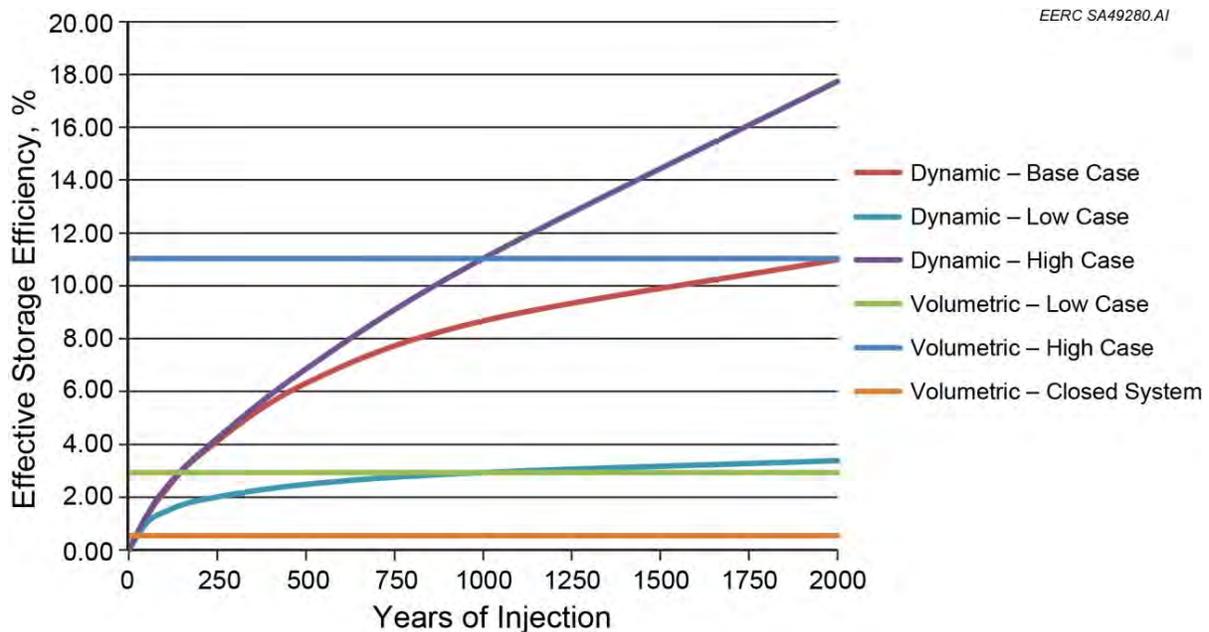


Figure ES-1. The dynamic CO<sub>2</sub> storage efficiency of open systems is very time-dependent and slowly reaches an asymptote over time which approaches the volumetric effective CO<sub>2</sub> storage efficiency, as shown here with the open-system Minnelusa Formation.

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## **INTRODUCTION**

As concern continues to mount over climate change, strategies are being considered to reduce anthropogenic carbon dioxide (CO<sub>2</sub>) emissions. One of the primary methods under consideration is CO<sub>2</sub> storage in deep saline formations (DSFs); however, the amount of CO<sub>2</sub> to be stored in order to make a significant reduction in annual emissions is on the order of hundreds of millions of tonnes of CO<sub>2</sub> a year. As a result, there is concern whether or not sufficient storage capacity in these types of formations exists. To increase stakeholder confidence, several methods have been developed to estimate the CO<sub>2</sub> storage capacity, or CO<sub>2</sub> storage resource potential, of DSFs, including methods developed by the U.S. Department of Energy (DOE) (2007, 2008, 2010; Litynski and others, 2010), the Carbon Sequestration Leadership Forum (CSLF) (2005, 2007, 2008; Bachu and others, 2007; Bradshaw and others, 2007), the IEA Greenhouse Gas R&D Programme (IEAGHG) (2009; Gorecki and others, 2009), the U.S. Geological Survey (USGS) (Brennan and others, 2010; Blondes and others, 2013), CO<sub>2</sub> GeoCapacity (Vangkilde-Pedersen and others, 2009), Zhou and others (2008), and Szulczewski and others (2012). These methods are based on volumetric approaches that do not consider the effect of site-specific dynamic factors such as injection rate, injection pattern, timing of injection, and pressure interference between injection locations. These methods may be excellent for comparing the potential between particular formations or basins, but they lack consistency between methods and have not been validated through real-world experience or full-formation injection simulations. As such, these methodologies may over- or underestimate the effective storage resource potential in DSFs. Numerical simulation is a method that can be used to validate the estimate of the effective storage resource potential of DSFs by addressing the effects of multiple large-scale CO<sub>2</sub> injections. Several studies have investigated the use of numerical simulation for determining the dynamic storage capacity of DSFs; however, these studies have not examined scenarios of injection into the entire effective reservoir volume but instead have focused on looking at pressure interference between injection sites, pressure buildup or relief, and brine migration within the same formation (Zhou and Birkholzer, 2011; Birkholzer and Zhou, 2009; IEA Greenhouse Gas R&D Programme, 2010; Nicot, 2008). Because of the concerns about the validity of the current CO<sub>2</sub> storage resource estimation methodologies, the main goal of this project is to compare volumetric storage resource estimates with estimates made using numerical simulation, referred to as dynamic storage resource. The Energy & Environmental Research Center (EERC) used these two approaches to estimate the effective CO<sub>2</sub> storage resource and efficiency of two deep saline systems, namely, the Minneulsa Formation in the Powder River Basin, United States, and the Qingshankou and Yaojia Formations (which act as a single-flow unit) in the Songliao Basin, China. The resulting storage resource estimates made with the dynamic and volumetric methods will be compared for the two case studies, and conclusions will be drawn based on the results of this comparison.

## **BACKGROUND**

### **Saline Formations**

Sedimentary basins exist around the world and consist of thick successional geologic formations, often consisting of DSFs. These DSFs offer the greatest potential for storage of anthropogenic CO<sub>2</sub> because of their large pore volume and spatial distribution. The characteristics of DSFs include the following: 1) they exist at a depth where CO<sub>2</sub> will reside in a dense, supercritical phase, typically at depths greater than 800 meters; 2) they contain formation fluids with total dissolved solids (TDS) in excess of the cutoff for protected underground sources of drinking water (USDW) (e.g., 10,000 ppm in the United States); and 3) they are overlain by a thick, laterally continuous sealing formation with properties that preclude vertical migration of the injected CO<sub>2</sub>.

### **Open, Closed, and Semiclosed Systems**

When a DSF is assessed for storage resource potential, it is important to understand the hydrogeology of the system and determine what type of boundary conditions exist. Zhou and others (2008) nicely illustrate the various boundary conditions in the concept of open, closed, and semiclosed systems (Figure 1). Saline formations typically have a large areal extent and often act as open systems; however, there are cases in which they are compartmentalized by lateral flow boundaries created by stratigraphic pinch-outs or sealing faults. In these cases, the saline formation acts in a closed or semiclosed manner, as suggested by Zhou and others (2008). In addition to the lateral boundaries, the properties of the sealing formations are also important, as it is possible to displace the in situ fluid out of the DSF and into the cap rock without allowing the injected CO<sub>2</sub> to migrate out of the formation because of capillary forces (IEA Greenhouse Gas R&D Programme, 2010; Cavanagh and Wildgust, 2011). A previous investigation by Permedia (IEA Greenhouse Gas R&D Programme, 2010) demonstrated that it is possible to have formation seals with permeability at a level where in situ formation fluids can move out of the injection formation while retaining the injected CO<sub>2</sub> and result in an open or semiopen system, even if the formation has lateral boundaries that are closed. The concepts of open, closed, and semiclosed systems are important to this study as they directly relate to the pressure buildup and fall off, as well as brine movement, that can occur during the course of CO<sub>2</sub> injection in DSFs and could potentially limit the applicability or usefulness of volumetric storage resource estimates.

### **CO<sub>2</sub> Storage Mechanisms in Deep Saline Formations**

Geologic storage of CO<sub>2</sub> is accomplished through its injection into permeable formations where it is subsequently trapped by several physical and geochemical processes (Intergovernmental Panel on Climate Change, 2005). When CO<sub>2</sub> is injected, it can be physically trapped in structural or stratigraphic closures or as residual gas because of relative permeability hysteresis. Geochemically, CO<sub>2</sub> can be trapped by adsorption onto organic material or through dissolution into the formation brine (solubility trapping), where it can interact with the rock matrix and eventually precipitate into stable carbonate minerals (mineral trapping). Injected CO<sub>2</sub>

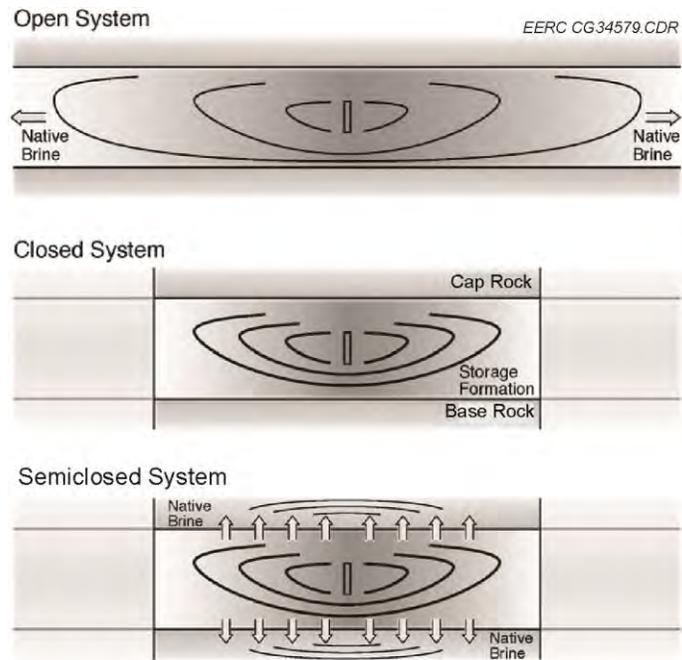


Figure 1. Diagram representing the three potential storage systems (from Zhou and others, 2008).

can also be trapped through hydrodynamic trapping, which is a complex combination of the previously mentioned trapping mechanisms (Intergovernmental Panel on Climate Change, 2005). When the storage resource potential of a geologic storage target is considered, each of the trapping mechanisms has differing importance on different time scales. Figure 2, from the Intergovernmental Panel on Climate Change (2005) special report on climate change, illustrates the relative importance of each trapping mechanism over time.

Physical trapping occurs immediately after CO<sub>2</sub> is injected into a permeable formation below a low-permeability regional seal. CO<sub>2</sub> is immobilized through physical trapping when it is trapped in structural or stratigraphic traps by the buoyancy forces created by the density difference between the injected CO<sub>2</sub> and the formation water.

Residual CO<sub>2</sub> trapping occurs because of relative permeability hysteresis. This process occurs after the injection operations stop as the CO<sub>2</sub> moves away from the original injection point and the displaced brine imbibes back into the pore space previously occupied by CO<sub>2</sub> and traps a portion of the retreating CO<sub>2</sub>. Because residual trapping occurs primarily after injection operation ceases, it does not play an important role in estimating storage efficiency or the amount of CO<sub>2</sub> that can be stored (IEA Greenhouse Gas R&D Programme, 2009).

Solubility trapping occurs when injected CO<sub>2</sub> mixes with the formation waters and a portion of the injected CO<sub>2</sub> subsequently dissolves into the formation waters. The amount of CO<sub>2</sub> that dissolves into the formation water is a function of temperature, pressure, and water salinity. Solubility trapping occurs immediately after injection begins and is dependent on the amount of

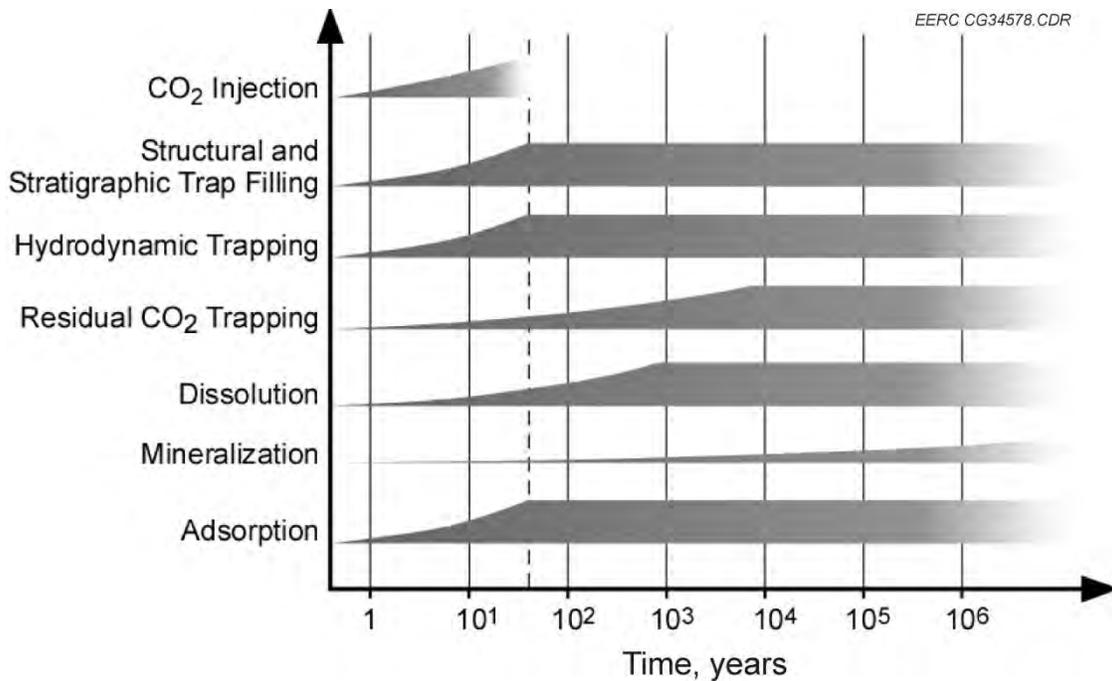


Figure 2. Over the course of a CO<sub>2</sub> storage project, the physical and geochemical processes and the relative importance of each change over time (Intergovernmental Panel on Climate Change, 2005).

mixing between the injected CO<sub>2</sub> and the formation waters. Solubility trapping can play an important role in the long-term trapping of CO<sub>2</sub>, and once CO<sub>2</sub> becomes dissolved, the CO<sub>2</sub> takes up much less space in the reservoir, allowing more CO<sub>2</sub> to be injected, possibly increasing the storage potential of a formation.

Mineral trapping occurs after the injected CO<sub>2</sub> is dissolved in the formation waters and is a geochemical process where the formation waters, injected CO<sub>2</sub>, and the formation rock interact and precipitate minerals. Mineral precipitation is the least well understood, and it is believed that it will only become an important trapping mechanism on very long time frames, on the order of tens to hundreds of thousands of years (Carbon Sequestration Leadership Forum, 2005; Intergovernmental Panel on Climate Change, 2005).

CO<sub>2</sub> can also be trapped hydrodynamically; this occurs when CO<sub>2</sub> is injected into a formation where there are no large structural or stratigraphic closures to contain it laterally (Intergovernmental Panel on Climate Change, 2005). The injected CO<sub>2</sub> moves away from the source both upward until it contacts the cap rock and laterally until natural formation pressure gradients, and corresponding in situ fluid flow, exceed the forces driving CO<sub>2</sub> flow. At this point, the injected CO<sub>2</sub> is eventually trapped through physical trapping, solubility, residual gas, and mineral trapping (Bradshaw and others, 2007).

On the timescales that are being considered for geologic CO<sub>2</sub> storage, it is likely that the most important trapping mechanisms for storing CO<sub>2</sub> in saline formations will be physical and hydrodynamic trapping and, to a lesser extent, solubility trapping.

### **Volumetric and Dynamic CO<sub>2</sub> Storage Resource Estimates**

Volumetric CO<sub>2</sub> storage resource estimates are conducted by calculating or estimating the pore volume of the storage target (a field, a portion or all of a saline formation, a geologic basin, etc.) and then multiplying the volume by an appropriate storage efficiency term (E). The pore volume of an area is estimated by multiplying the porosity by the average thickness and total area. The efficiency term (E) represents the fraction of the pore volume that CO<sub>2</sub> can occupy and is affected by boundary conditions, sweep efficiency, heterogeneity, etc. Volumetric estimates do not consider things such as number of wells, timing or length of injection, pressure buildup over time, or injection rate.

Dynamic CO<sub>2</sub> storage resource estimates are conducted by investigating the effective of dynamic variables such as the number of wells, length of injection, rate of injection, and the time required to inject a given mass of CO<sub>2</sub> into a target storage volume. This is typically accomplished by constructing geocellular models of the injection volume and running numerical simulations where different scenarios evaluate variables such as number and type of wells, rate of injection, length of injection, water extraction, and other optimization techniques. The storage efficiency term can be estimated at any time by dividing the mass of CO<sub>2</sub> injected by the total mass of CO<sub>2</sub> that could have been stored if all of the pore space of the target storage volume had been filled with CO<sub>2</sub>. It should be noted that, in a dynamic estimate, the storage efficiency changes with time, starting very low and increasing over time, as long as the total storage volume remains the same.

## **APPROACH**

### **Methodology Comparison and Selection**

The first effort in this work focused on identifying the existing published methodologies for estimating the volumetric “static” CO<sub>2</sub> storage resource of DSFs developed in previous work. In order to compare the methods on a consistent level, the CO<sub>2</sub> storage resource classification system developed in the IEAGHG report on CO<sub>2</sub> storage efficiency (IEA Greenhouse Gas R&D Programme, 2009) was used (Figure 3). This system builds off of the terminology and classification systems developed by DOE (2008), CSLF (2007), the Society of Petroleum Engineers (SPE) and others (2007), and the Cooperative Research Center for Greenhouse Gas Technologies (CO<sub>2</sub>CRC) (IEA Greenhouse Gas R&D Programme, 2008) and combines them into a classification system utilizing a consistent terminology to evaluate a storage estimate in a stepwise fashion. Theoretical storage resource is the base of this classification system and represents the absolute total pore volume within a rock formation. At this level, the theoretical maximum, no restrictions are placed on the formation geology. The characterized storage resource is a subset of the theoretical storage resource that considers only the geology with properties making it amenable to CO<sub>2</sub> storage, e.g., good porosity and permeability. Effective

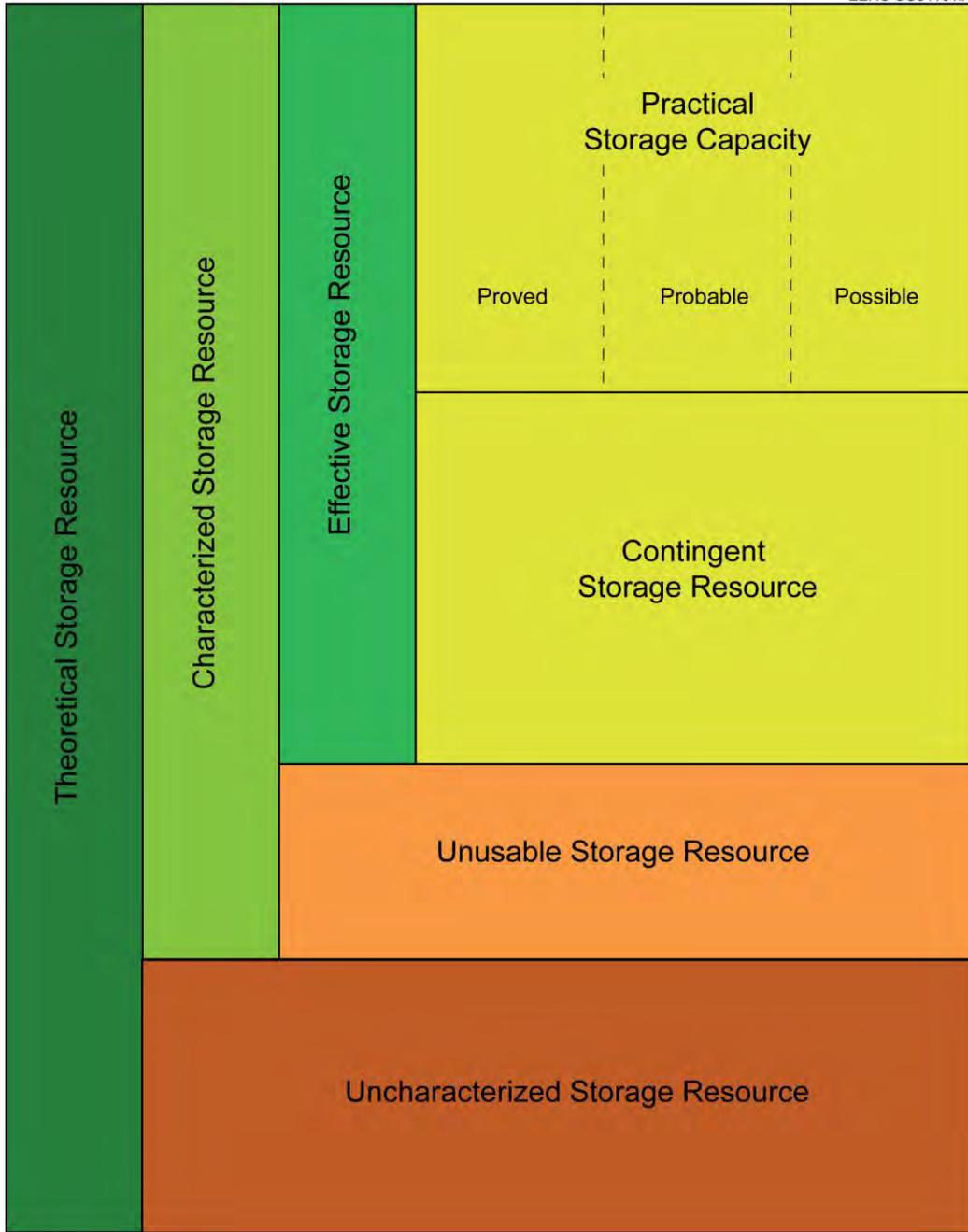


Figure 3. Storage resource/capacity classification system (IEA Greenhouse Gas R&D Programme, 2009).

storage resource further refines this estimate by considering the technical limitations that may constrain the amount of CO<sub>2</sub> that may be stored in a target formation, e.g., injectivity. The effective storage resource is the level at which most of the published CO<sub>2</sub> storage resource estimation methodologies evaluate the CO<sub>2</sub> storage in saline formations. In order to further refine the effective storage resource, economic limitations are applied, with this level referred to as the practical storage capacity. The practical storage capacity estimates for CO<sub>2</sub> storage are equivalent to a reserve estimate in the oil and gas industry. An important distinction is made between storage resources that are viable under current economic conditions (practical) versus future economic conditions (contingent). It is acknowledged that, at this time, there is an absence of a well-established carbon market to make the estimation of practical storage capacities possible; however, it is useful to define such classifications since economic and commercial implications could be considered as the industry matures (IEA Greenhouse Gas R&D Programme, 2009).

While the existing storage resource estimation methodologies were evaluated, it was important to consider them on a consistent basis. The effective storage resource level of the previously described classification system seemed to be the best basis for comparison, as it considers both the geologic and technical constraints affecting the CO<sub>2</sub> storage potential of a given saline formation. The literature examines several methodologies, including those developed by the CSLF (Carbon Sequestration Leadership Forum, 2005 and 2007), DOE (U.S. Department of Energy, 2008 and 2010), the USGS (Brennan and others, 2010), Szulczewski and others (2012), and Zhou and others (2008). It was decided that the methodology utilized in the 3rd edition of the Carbon Sequestration Atlas of the United States and Canada (U.S. Department of Energy, 2008, 2010, 2012) would be utilized since previous work has compared it to the CSLF methodology and found it to be equivalent (IEA Greenhouse Gas R&D Programme, 2009). Additionally, the DOE (2008 and 2010), CSLF (2007), USGS (Brennan and others, 2010), Szulczewski and others (2012), and Zhou and others (2008) methods have been compared, with all resulting in CO<sub>2</sub> storage resource potential values on the same order of magnitude (U.S. Department of Energy, 2012). As a result, it was determined that the DOE method presented in the 2010 Atlas (U.S. Department of Energy, 2010) would adequately represent all volumetric CO<sub>2</sub> storage resource estimation methodologies. Also, since the closed-system compressibility method described by Zhou and others (2008) consistently resulted in some of the lowest storage resource estimates, it was determined that the closed-system approach and resulting coefficients would be used for comparison purposes.

### **Effective Volumetric CO<sub>2</sub> Storage Resource Estimation Methodologies**

The basis for all DSF volumetric CO<sub>2</sub> storage resource estimation methodologies is essentially the pore volume of the storage target multiplied by some “efficiency” term (E), multiplied by the density of the CO<sub>2</sub> at reservoir conditions ( $\rho_{CO_2}$ ), resulting in a CO<sub>2</sub> storage resource potential defined as the mass of CO<sub>2</sub> that could be stored in the target formation ( $M_{CO_2}$ ) (Equation 1). The pore volume is typically defined as the total area ( $A_t$ ), multiplied by the gross thickness ( $h_g$ ), multiplied by the effective porosity ( $\varphi_t$ ), but pore volume was more accurately described by the CSLF (2007) by integrating porosity in three dimensions (Equation 2), as porosity is a heterogeneous property that typically varies quite widely throughout any formation.

$$M_{CO_2} = A_t * h_g * \varphi_t * E * \rho_{CO_2} \quad [\text{Eq. 1}]$$

$$M_{CO_2} = \iiint \varphi_t dx dy dz * E * \rho_{CO_2} \quad [\text{Eq. 2}]$$

The efficiency term (E) represents the percentage of the formation's pore volume that can be occupied by CO<sub>2</sub> and is represented differently between open and closed systems. In open systems, the efficiency term represents the fraction of the geology that is amenable to storage and the portion of that pore space that CO<sub>2</sub> can occupy by displacing the original formation fluids during the course of injection ( $E_E$ ) (Equation 3). The amenable geology is defined as the fraction of the total formation volume that has suitable geology for CO<sub>2</sub> storage ( $E_{geol}$ ) and is a multiplicative combination of the net-to-total area ( $E_{A_n/A_t}$ ), the net-to-gross thickness ( $E_{h_n/h_g}$ ), and the effective-to-total porosity ( $E_{\varphi_{eff}/\varphi_t}$ ) (Equation 4).  $E_{geol}$  is generally defined as the area where there is sufficient formation at a depth where CO<sub>2</sub> will remain in the supercritical state, typically around 800 meters, and in some jurisdictions, where the salinity of the formation fluids is above the TDS cutoff for protected USDW (10,000 ppm in the United States). It also excludes intervals in the formation with unsuitable geology for injection. The second factor contained in  $E_E$ , the displacement efficiency ( $E_D$ ), is split into the volumetric displacement efficiency ( $E_{vol}$ ) and the microscopic displacement efficiency ( $E_d$ ). The volumetric displacement efficiency is the combined fraction of the pore volume that can be contacted by CO<sub>2</sub> from injection wells and the fraction of the net thickness that is contacted by CO<sub>2</sub> as a result of the density difference between the injected CO<sub>2</sub> and the formation fluids. The microscopic displacement efficiency represents the fraction of the contacted pore space that can be filled by CO<sub>2</sub> and is directly related to the irreducible water saturation.

$$E_E = E_{geol} * E_D \quad [\text{Eq. 3}]$$

$$E_{geol} = E_{A_n/A_t} * E_{h_n/h_g} * E_{\varphi_{eff}/\varphi_{tot}} \quad [\text{Eq. 4}]$$

$$E_D = E_{vol} * E_d \quad [\text{Eq. 5}]$$

In closed systems, the effective storage resource estimate is made by multiplying the total pore volume by a compressibility efficiency term ( $E_{comp}$ ). The compressibility efficiency represents the fraction of the pore space that is amenable to storage through the compression of the formation fluids ( $c_w$ ), dilatation of the pores ( $c_f$ ), and the pressure space created by the difference between the final pressure and the initial pressure ( $\Delta P$ ) (Equation 6) (Zhou and others, 2008).

$$E_{comp} = \Delta P * (c_w + c_f) \quad [\text{Eq. 6}]$$

## Geologic Modeling

Geologic modeling was used as the basis for comparison of the volumetric and dynamic CO<sub>2</sub> storage resource estimates and provides a way to compare estimates in an “apples to apples” manner. This begins with a literature review of the readily available published and unpublished site-specific data for any target formation. The data that can be compiled for targeted formations include structure contour maps, isopach maps, facies maps, geophysical well logs, core analysis data, and general geologic interpretations. The most beneficial data in saline formation evaluations

include maps representing properties for the entire formational extent across the given geologic basin. These data are then further conditioned with geophysical well logs from the formation that best represent the properties of the formation of study and are used to reduce uncertainty in the basin-scale models. Geologic interpretation includes cross sections, petrophysical results, and structure tops; these descriptions are used to help guide the model development.

In this study, data from the literature review were compiled into relational databases in order to organize, correlate, and export the data in useful formats. Gathered structure and isopach maps were digitized using GIS (geographic information system) and exported as grid points representing measured depth or thickness. Geophysical logs were categorized according to type and assigned to the appropriate well with a spatial location. Structural tops were loaded from available sources or picked based on geological interpretation. Core analysis data were imported to display histograms for porosity and permeability and their correlative relationship.

Following site characterization and compilation of geologic properties, a static 3-D geologic modeling workflow was performed by building a structural framework; performing petrophysical interpretation; performing data analysis; conducting a geostatistical interpolation of reservoir properties into a 3-D model; performing uncertainty analysis to create high, mid, and low pore volume cases; upscaling for dynamic simulation; and calculating the volumetric CO<sub>2</sub> storage resource potential (Figure 4).

The structural framework for these models are built containing three main contour surfaces that stretch across the entire basin of interest: the top representing the ground surface elevation, the structural top of the DSF of interest, and the base of the DSF. This creates two main zones of the model: the top representing the cap rock and overburden and the bottom being the reservoir of interest. The reservoir is further split into major flow zones as necessary. These zones were created by interpolating the grid points derived from structure and isopach maps and were further refined by available or picked structural well log tops.

Petrophysical interpretation is performed using Schlumberger's Techlog to first develop a shale volume model using available gamma ray logs and appropriate cutoff. The calculated shale volume is used to construct a facies model utilizing any other available geophysical logs. A porosity model is developed and directly correlated to each facies. Crossplots are created to examine core analysis data in order to produce a permeability model. This bivariate distribution of porosity and permeability is utilized in the model to create a dynamic relationship between porosity and permeability that will be utilized during geostatistical modeling.

The goal of data analysis is to geostatistically determine the vertical and lateral relationship among reservoir properties, thus representing the formation's heterogeneity and honoring the spatial correlation of the input data. A vertical variogram helps determine the additional layering that was added to each flow zone. The horizontal variogram establishes connectivity between control points and creates a directional and spatial model to follow outside of well control.

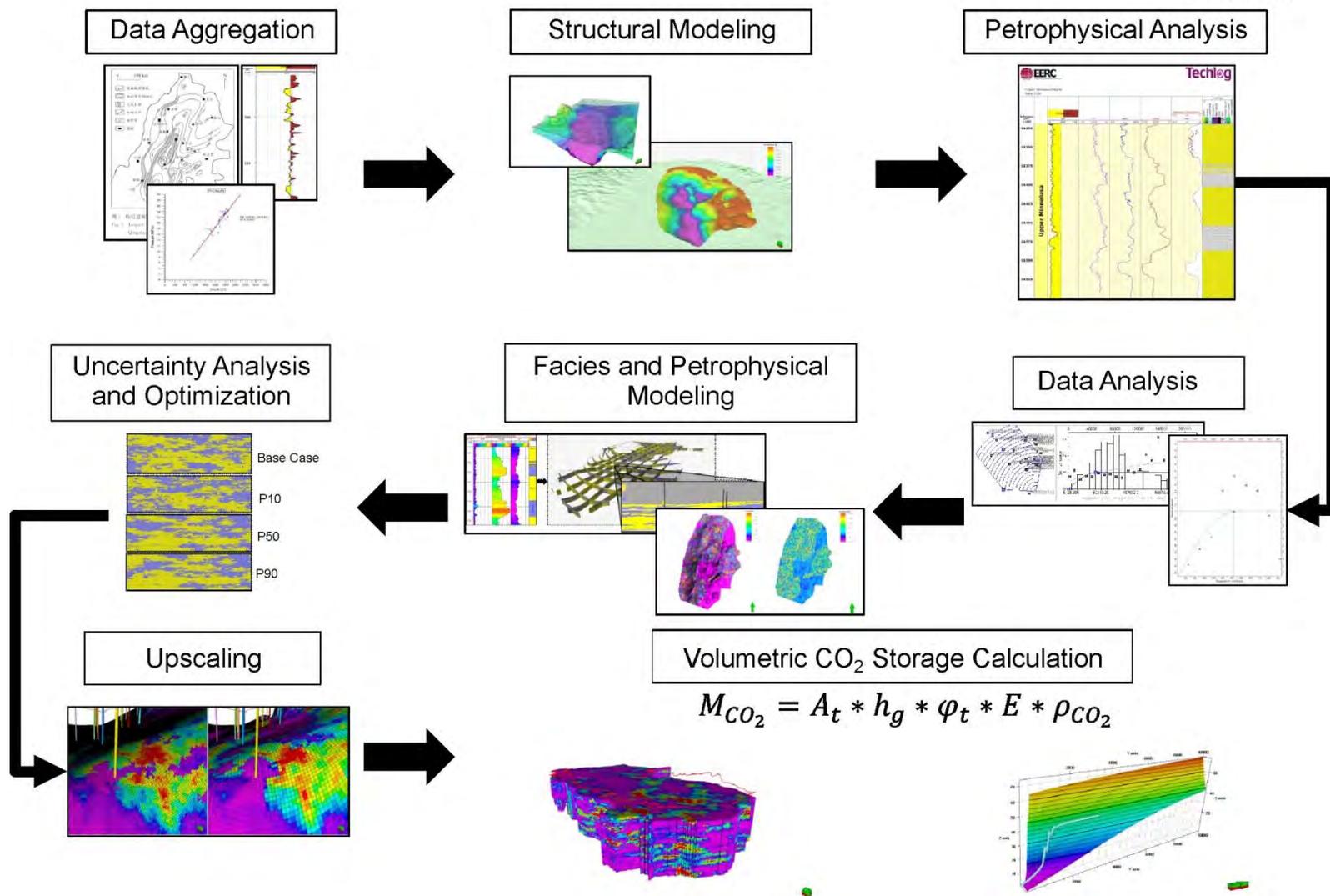


Figure 4. Workflow for the construction of geocellular models to calculate the effective storage resource potential. Each model is then passed on to simulation to perform a dynamic effective storage resource estimate.

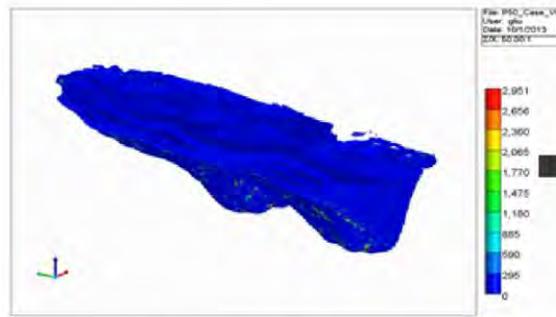
A 3-D model is constructed by combining the structural framework, petrophysics, and data analyses into a geocellular model with the following properties: facies, porosity, and permeability. Temperature and pressure are populated in the model for determining fluid properties such as CO<sub>2</sub> density, viscosity, and dissolution coefficients used in dynamic simulation. Additionally, TDS information is used in the dynamic simulation as a parameter for fluid properties and can be used in the volumetric model as a way to eliminate portions of the geologic formation where TDS values are below the threshold permitted to inject CO<sub>2</sub>, as well as calculating dissolution of CO<sub>2</sub>. Sequential indicator simulation stochastic modeling is used to populate the facies property. This approach honors the proportional input data from the petrophysical workflow for each facies and the variograms from the data analysis, which helps to optimize the distribution of model properties. Porosity and permeability were distributed by Gaussian random function simulation and conditioned to the facies property. The porosity and permeability properties are populated using a bivariate distribution established in the petrophysical workflow. Each facies has its own statistical set of porosity and permeability values. A total pore volume can then be established for each base case model.

High, mid, and low case pore volume realizations are computed for each model by performing uncertainty analysis on the facies property. The facies property was the most uncertain reservoir property in both models, and its uncertainty has a large effect on the connected volumes and overall pore volume. By randomly varying the good reservoir facies, different probabilistic models were produced which resulted in high, mid, and low pore volume cases to evaluate the effect on storage coefficients. The high case is a 90th percentile (P90) and contains more of the primary storage facies and more pore volume, while the low case is a 10th percentile (P10) and has less primary storage facies and less total pore volume. The mid case is represented by a 50th percentile (P50) and is similar to the base case realization. In order to compare volumetric and dynamic approaches to storage resource potential, the static models are prepared for numerical simulation using upscaling methods. Static models are upscaled to reduce overall cell count while still honoring the geologic heterogeneity. At this point, the effective volumetric storage resource can be calculated for each pore volume model representing the formation extent in the basin.

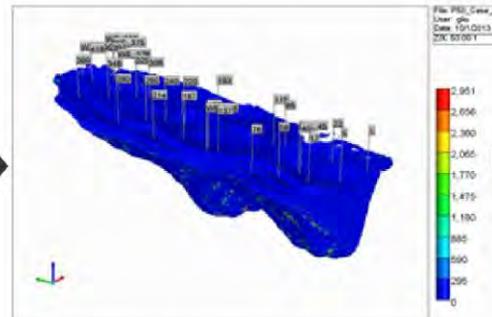
### **Dynamic Modeling**

Following upscaling and calculation of the effective volumetric CO<sub>2</sub> storage resource potential, simulation is performed on the same upscaled models to determine the effective dynamic CO<sub>2</sub> storage resource potential and efficiency. The dynamic simulation workflow is conducted by importing and quality-controlling the geologic models, determining injection simulation design, exploring boundary conditions, enhancing operational storage capacity, and calculating the effective dynamic CO<sub>2</sub> storage resource potential and efficiency. Finally, the estimates made using the volumetric approach can be compared to those estimated through the dynamic simulation (Figure 5).

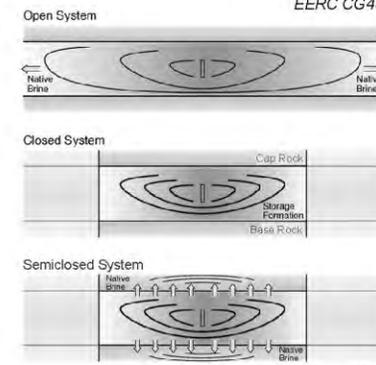
Grid sensitivity analysis, numerical tuning, injection rate sensitivity analysis, and dynamic simulations are performed using the Computer Modelling Group's GEM software. To better understand the uncertainty in some of the formation properties and to test different operation conditions, twelve simulation cases were performed on each case study. The mid case was considered the base case model and had initial simulations performed followed by optimization



Geocellular Models with High, Mid, and Low Pore Volume

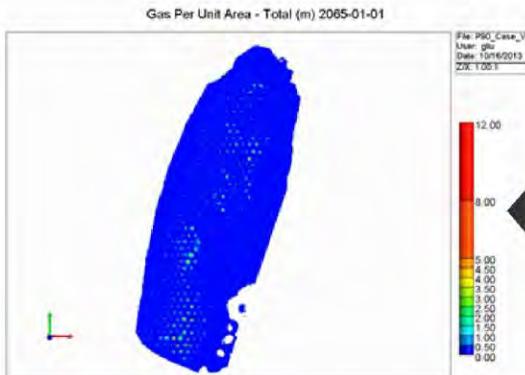


Injection Simulation Design

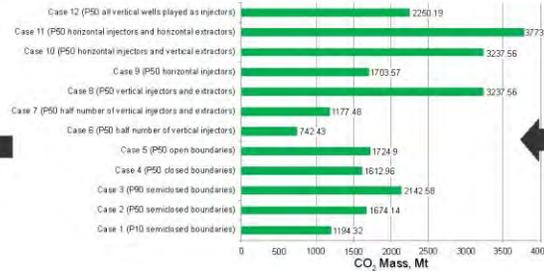


(Zhou et al., 2008)

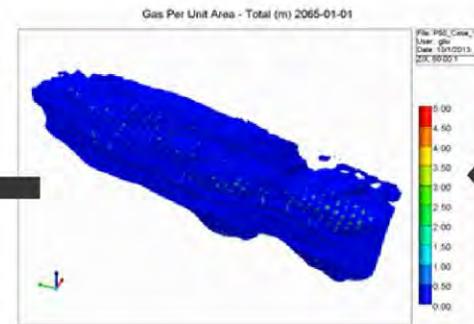
Boundary Condition Explorations



Storage Resource Comparisons and Analysis



Dynamic Storage Resource Plays



Operational Storage Resource Enhancement

Figure 5. A dynamic modeling workflow was developed for estimating the dynamic CO<sub>2</sub> storage resource potential for each case study.

techniques looking into injection simulation design, boundary conditions, and operational storage capacity enhancements. High and low cases were also simulated but with minimal optimization scenarios.

Determining the ultimate effective storage resource of a target formation through dynamic simulation can be very difficult because of the very large extent and the number of wells that would be required to fully utilize the formation's pore volume. A python script was developed to determine the number of wells, well placement and pattern, and perforation intervals selecting location based on the best formation properties in the grid. This script allowed control of the spacing between wells, as well as the ability to determine which type of well to create, i.e., injector, producer, and horizontal wells. The script also calculates the maximum bottomhole pressure for each well based on a pressure gradient and the well's measured depth. In addition, the wells are perforated in cells that exceed an injectivity cutoff (permeability multiplied by thickness) for each well by summing the injectivity of the well's individual k-layers. These functions allowed the different realizations and operational considerations for each case to be populated quickly.

The simulations allowed for 50 years of continuous CO<sub>2</sub> injection followed by 50 years of postinjection to access plume movement and pressure transient. Regression functions were fitted to the results when plotted versus time to predict ultimate storage capacity for time beyond the simulation capabilities. This method was validated by running several of the simulation cases for each model until the function asymptote, thus recording maximum effective CO<sub>2</sub> storage resource potential and efficiency. The effective dynamic CO<sub>2</sub> storage resource potential and efficiency was then calculated on the high, mid, and low pore volume cases and was compared to the volumetric cases for each model.

## **CASE STUDIES**

### **Formation Selection**

Three DSFs were selected for this study, representing different depositional environments in different basins that may be considered for future CO<sub>2</sub> storage. These three formations (represented in two geologic models) cover similarly sized areas but contain different depositional environments, geologic properties, and flow properties. The first is the upper Minnelusa Formation, Powder River Basin, United States, representing a single flow unit consisting of aeolian sand dunes cemented and interspersed with carbonates, both with fair storage properties. The second and third formations are the Qingshankou and Yaojia Formations, Songliao Basin, China. Although the Qingshankou and Yaojia are separate formations, they act as a single flow unit and were modeled as one system representing a stacked storage system consisting of deltaic-fluvial deposits with good storage properties separated by lacustrine muds with low storage potential (Figure 6). Both study areas are in intermontane basins; however, the Qingshankou and Yaojia system does not have areas of discharge and recharge while the Minnelusa does. This results in the Minnelusa Formation acting more as an open system, while the Qingshankou and Yaojia system is expected to behave in more of a closed or semiclosed manner.

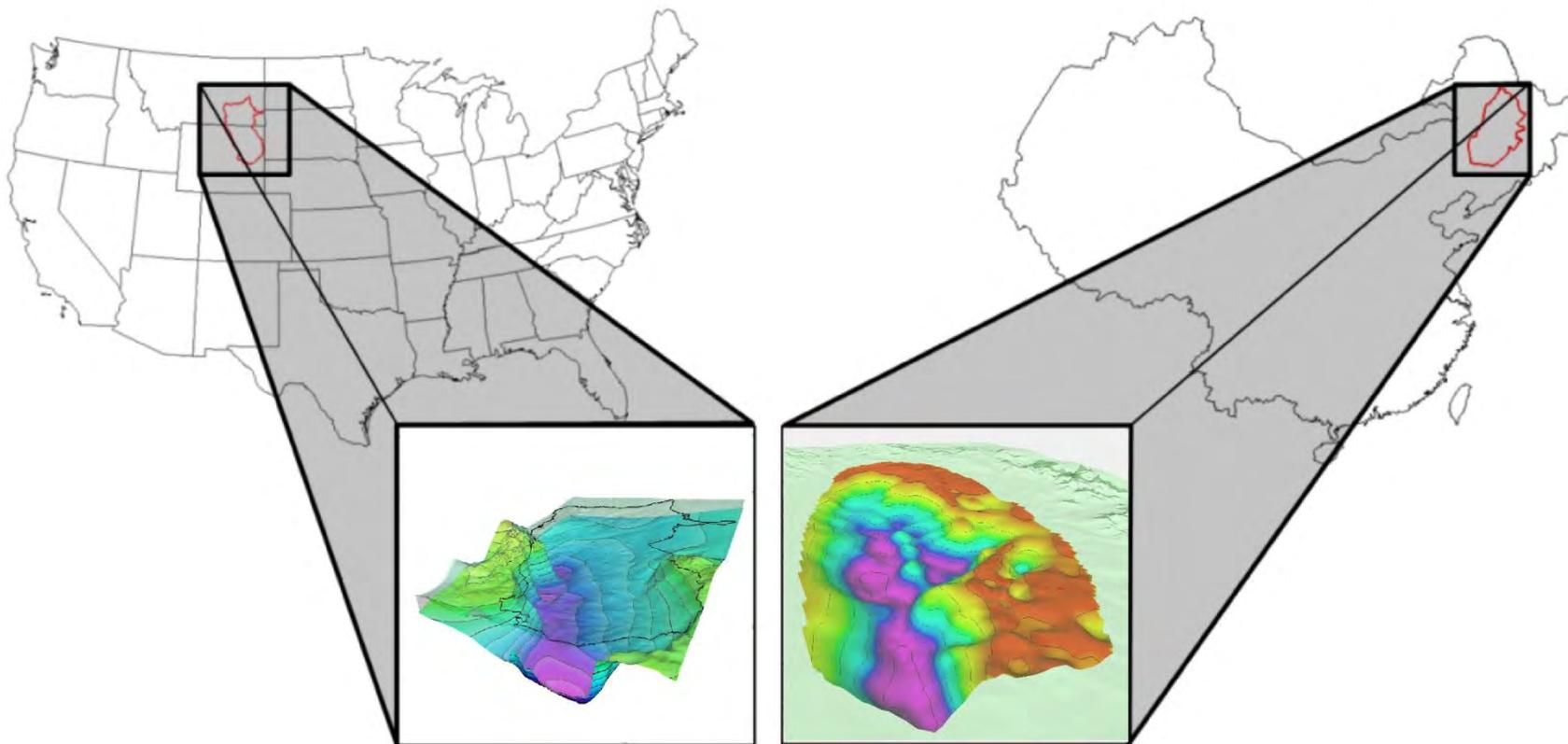


Figure 6. Geographic location of the Minnelusa Formation (left) and Qingshankou–Yaojia system (right).

The detailed description and development of both geocellular models are included in Appendix A. The resulting pore volumes for both the upper Minnelusa and Qingshankou–Yaojia systems are included in Tables 1 and 2.

## VOLUMETRIC CO<sub>2</sub> STORAGE RESOURCE ESTIMATION

The completed, upscaled geocellular models were now ready to be utilized to estimate the effective storage resource potential of the different model realizations. The total pore volume in each model was clipped sequentially to calculate the fraction ( $E_{geol}$ ) of the formations that is amenable to storage. This was accomplished by first clipping the model to an effective area ( $E_{A_n/A_t}$ ) by removing the areas where CO<sub>2</sub> could not be injected because of insufficient depth or because TDS values fall into the range of protected USDWs. Then a portion of the net thickness ( $E_{h_n/h_g}$ ) was removed by clipping out the nonreservoir facies. Next, using an effective porosity cutoff ( $E_{\phi_{eff}/\phi_t}$ ) of 7% for the Minnelusa and 14.5% Qingshankou–Yaojia, the rest of the noneffective porosity was removed (Figures 7 and 8). This porosity cutoff was determined by performing a detailed connected-volumes analysis. This type of analysis is conducted by creating connected volumes by selecting cutoff values for both porosity and permeability. All cells that meet the selected criteria are saved, while all others are made null. The saved cells are then viewed in 3-D and compared with the actual injectivity values used during numerical simulation. During the connected-volumes analysis, several values were used, both above and below the final selected porosity cutoff. From a reservoir flow standpoint, this method is used to eliminate poor-quality rock that would have low injectivity because of low flow zones. The porosity eliminated is known as microeffective porosity and usually is not interconnected or has low permeability. The eliminated pore volume in each system accounts for less than 1% of the total

**Table 1. Input Parameters Used for Upper Minnelusa Modeling and the Total Calculated Pore Volume for the P10, P50, and P90 Upper Minnelusa Formation Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Area	$A_t$	km <sup>2</sup>	70,300	70,300	70,300
Average Formation Thickness	$h_g$	m	73	73	73
Average Formation Porosity	$\phi_{tot}$		0.03	0.03	0.04
Total Formation Pore Volume	$V_{PV}$	km <sup>3</sup>	153	174	212

**Table 2. Input Parameters Used for Qingshankou–Yaojia System Modeling and the Total Calculated Pore Volume for the P10, P50, and P90 Qingshankou–Yaojia System Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Area	$A_t$	km <sup>2</sup>	123,000	123,000	123,000
Average Formation Thickness	$h_g$	m	370	370	370
Average Formation Porosity	$\phi_{tot}$		0.03	0.06	0.09
Total Formation Pore Volume	$V_{PV}$	km <sup>3</sup>	742	1290	1810

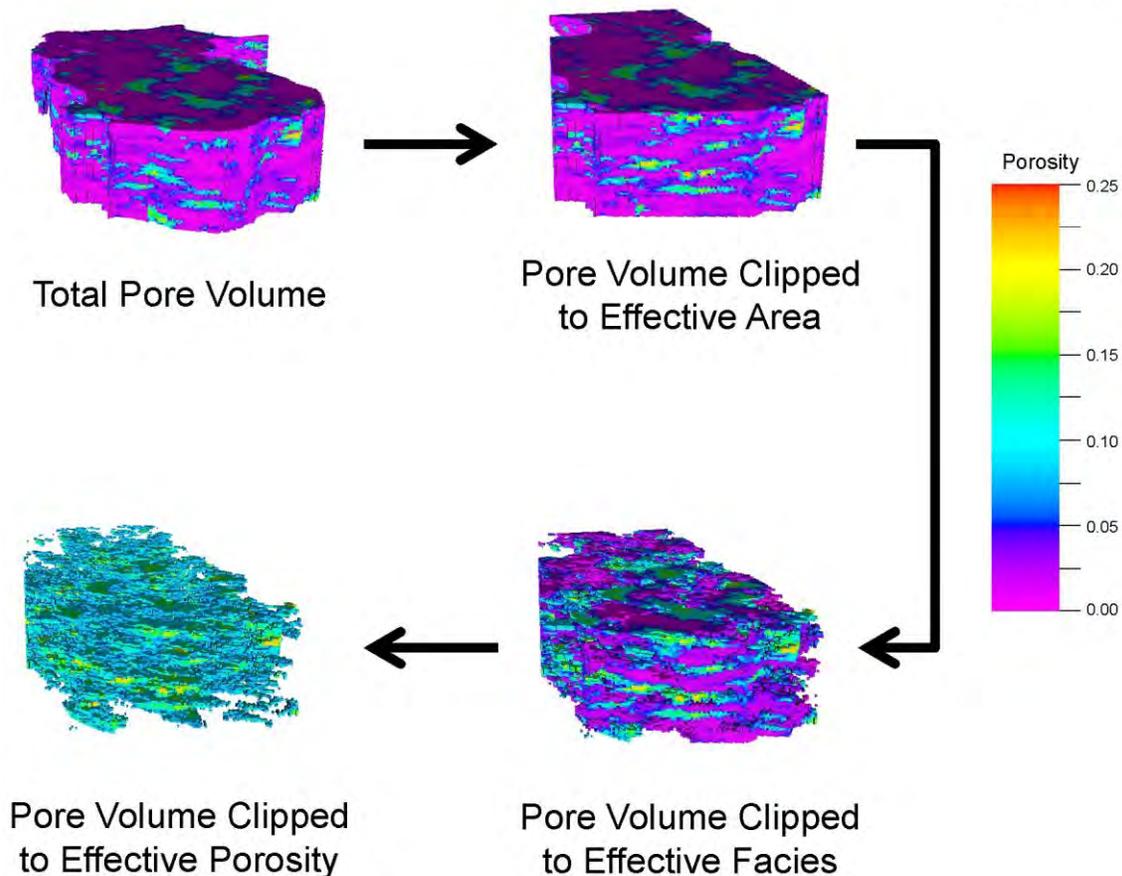


Figure 7. Sequential reduction in total pore volume to the effective pore volume in the upper Minnelusa Formation (the model is shown in Simbox (i.e., all of the cells have the same size and the thickness)).

pore volume in that system. The cutoff is different between the two systems because the rock quality is different, thus affecting the overall connected volumes. Figure 9 shows the permeability–porosity relationship for both systems. The selected porosity cutoffs for each system significantly reduced the cell count with permeabilities less than 5 mD in the Qingshakou–Yaojia system and less than 1 mD in the Minnelusa Formation. Figure 10 shows an example of connected volumes. Finally, the pore volume amenable to CO<sub>2</sub> storage was calculated for the P10, P50, and P90 realizations for each model (Tables 3 and 4).

Once the effective pore volume was estimated for each realization, the effective volumetric CO<sub>2</sub> storage resource was calculated. This was accomplished by using the displacement efficiency terms ( $E_D$ ) from the Carbon Sequestration Atlas of the United States and Canada (U.S. Department of Energy, 2010) (Table 5).

The values for the displacement efficiency terms in Table 5 can be used when the effective pore volume and the ratio of the effective-to-total geology ( $E_{geol}$ ) are known (U.S. Department of

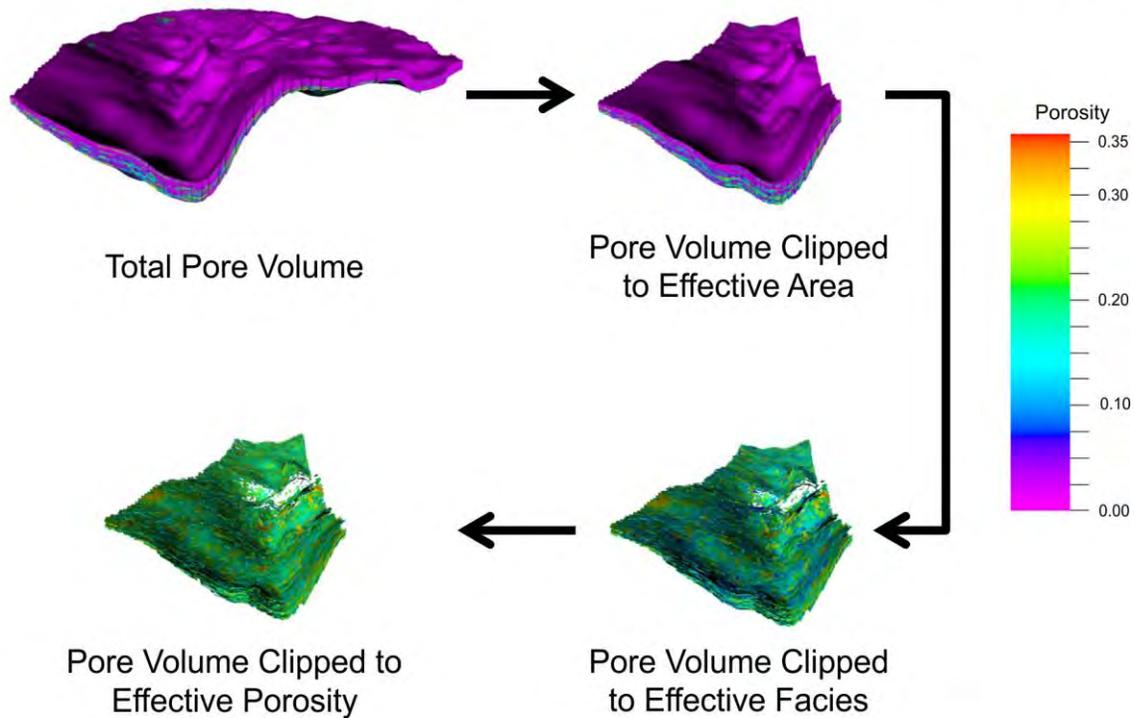


Figure 8. Sequential reduction in total pore volume to the effective pore volume in the Qingshankou–Yaojia system is used to estimate  $E_{geol.}$

Energy, 2010). Since the injectable portion of the upper Minnelusa is predominantly composed of aeolian sand deposits and the Qingshankou–Yaojia of fluvial sand deposits, the clastic formation volumetric displacement ( $E_D$ ) values from Table 5 were used to estimate the effective CO<sub>2</sub> storage efficiency for each DSF. The values for  $E_{geol}$  calculated from the geologic modeling (Tables 3 and 4) were multiplied by the appropriate  $E_D$  to calculate a P10, P50, and P90 value for the effective storage resource coefficient ( $E_E$ ), as shown earlier in Equation 3. Finally, using Equation 1, the effective storage coefficient was multiplied by the total pore volume for the P10, P50, and P90 model realizations and the expected CO<sub>2</sub> density at reservoir conditions at the end of injection to determine the effective CO<sub>2</sub> storage resource mass in each target formation (Tables 6 and 7).

If the upper Minnelusa Formation or the Qingshankou–Yaojia system were to behave as a closed system and not allow formation fluids to be displaced into the overlying formations, or laterally outward, then the closed-system compressibility method could be more applicable. The values for calculating the formation compressibility efficiency term and the resulting storage resource potential (Eq. 6) of the upper Minnelusa and Qingshankou–Yaojia P10, P50, and P90 models are shown in Tables 8 and 9, respectively. It is worth noting that in both the upper Minnelusa Formation and the Qingshankou–Yaojia system, the closed-system compressibility method results in an effective CO<sub>2</sub> storage resource estimate and effective storage efficiency that is an order of magnitude lower than the values estimated with the open-system methodology.

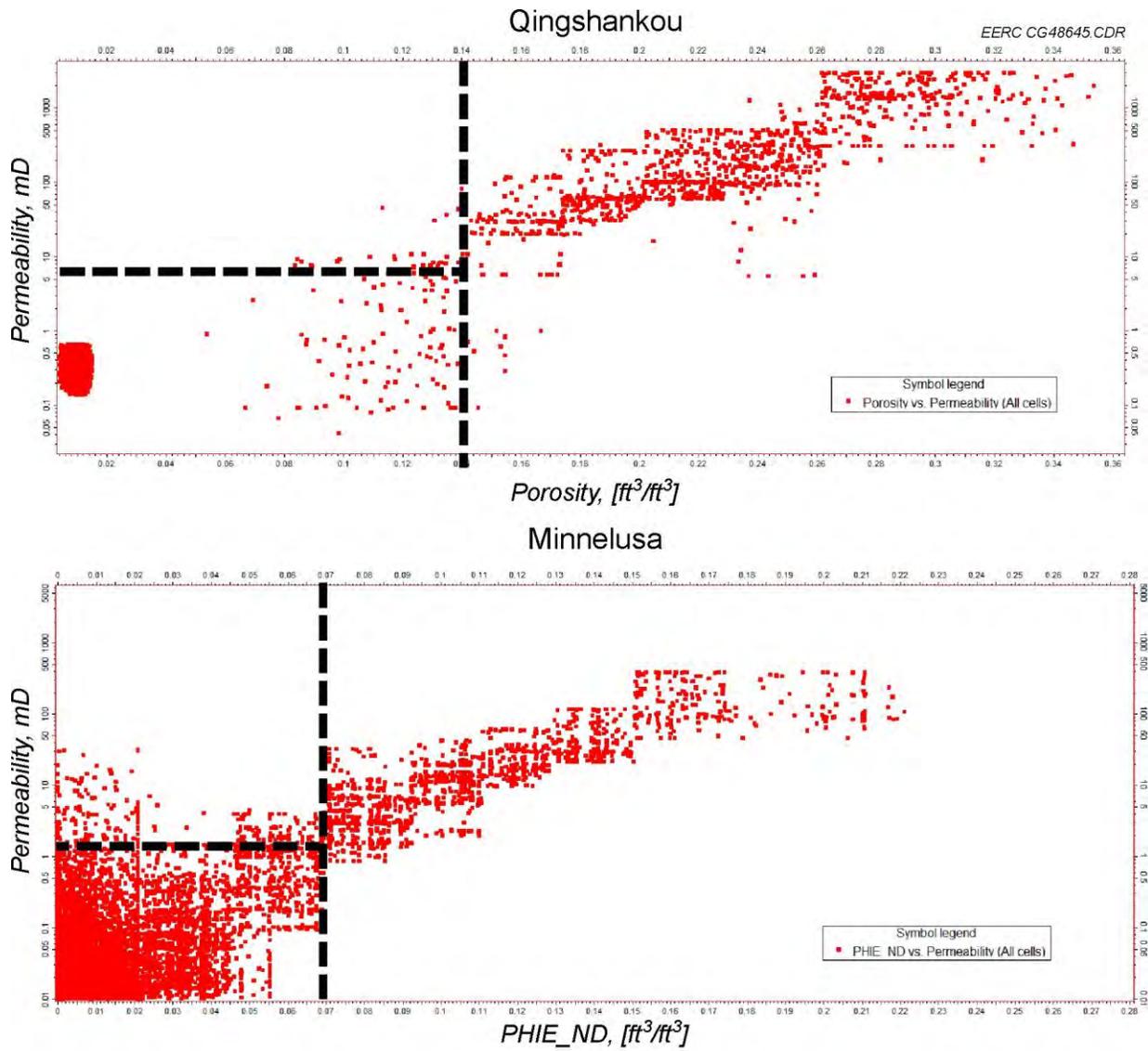


Figure 9. Permeability–porosity crossplot representing reservoir property values that are geostatistically populated into the geocellular model for the Qingshankou–Yaojia and Minnelusa systems. The vertical stippled line represents the cutoff point chosen to eliminate microporosity from the effective pore volume calculation, where all cells with values represented on the left side of the line are removed. The horizontal stippled line represents the connected-volumes permeability cutoff for reference; however, all of the cells represented above and below this line are removed from the effective pore volume calculation.

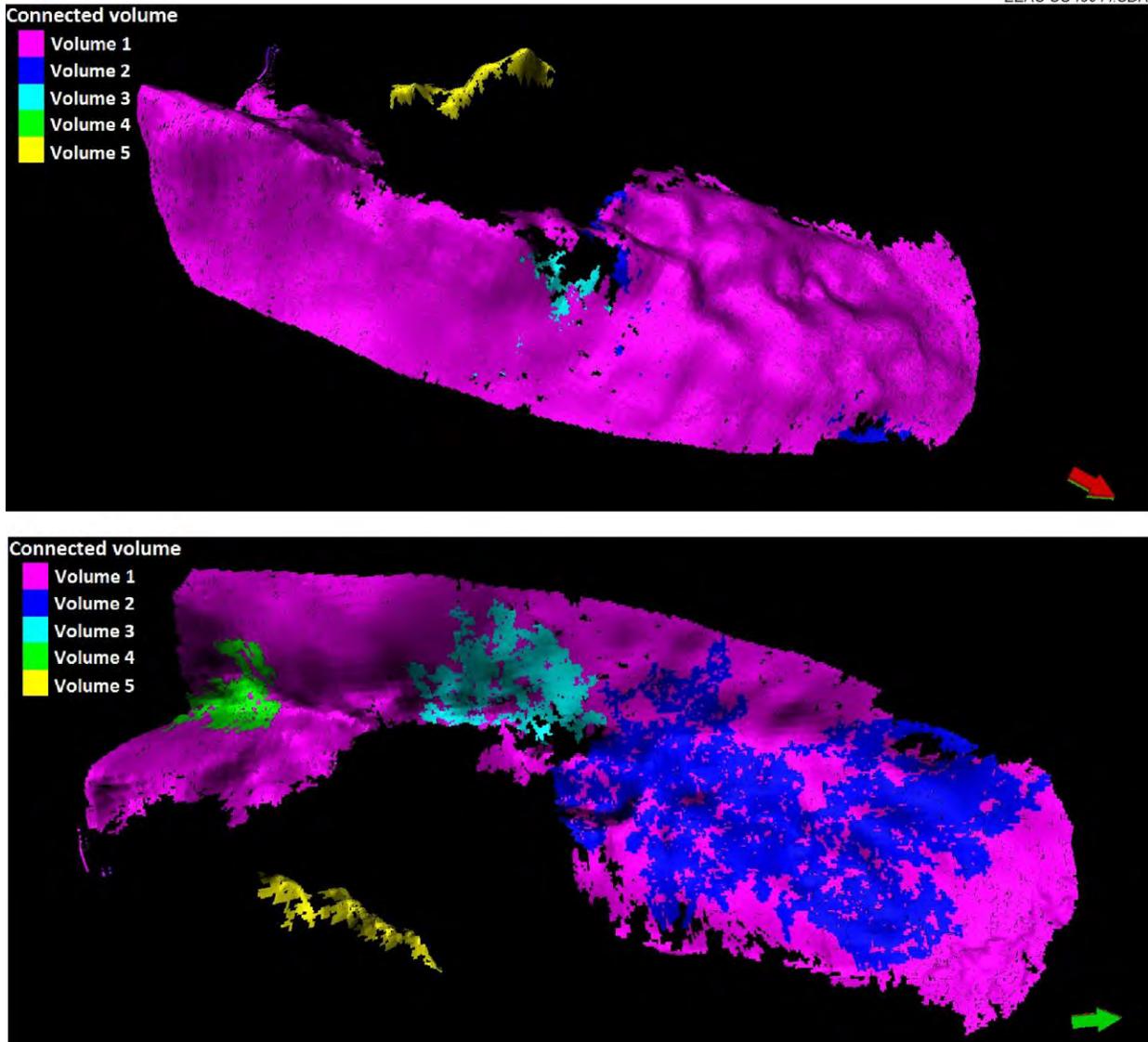


Figure 10. Connected-volumes analysis for the Qingshankou–Yaojia system. The top image is looking up from below the system. The bottom image is looking from the top down.

**Table 3. Effective Pore Volumes and Ratios for the P10, P50, and P90 Upper Minnelusa Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Pore Volume	$V_{PV}$	km <sup>3</sup>	153	174	212
Pore Volume Clipped to Effective Area	$V_{PVC}$	km <sup>3</sup>	130	151	178
Net-to-Total Area Percentage	$E_{A_n/A_t}$		85%	87%	84%
Pore Volume Clipped to Effective Facies		km <sup>3</sup>	101	127	158
Net-to-Gross Thickness Percentage	$E_{h_n/h_g}$		78%	84%	89%
Pore Volume Clipped to Effective Porosity Cutoff or Effective Pore Volume		km <sup>3</sup>	60.6	78.7	98.5
Effective-to-Total Porosity Percentage	$E_{\varphi_{eff}/\varphi_t}$		60%	62%	62%
Effective-to-Total Pore Volume Percentage	$E_{geol}$		40%	45%	47%

**Table 4. Effective Pore Volumes and Ratios for the P10, P50, and P90 Qingshakou–Yaojia Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Pore Volume	$V_{PV}$	km <sup>3</sup>	742	1290	1810
Pore Volume Clipped to Effective Area	$V_{PVC}$	km <sup>3</sup>	415	773	1120
Net-to-Total Area Percentage	$E_{A_n/A_t}$		56%	60%	62%
Pore Volume Clipped to Effective Facies		km <sup>3</sup>	168	507	818
Net-to-Gross Thickness Percentage	$E_{h_n/h_g}$		40%	66%	73%
Pore Volume Clipped to Effective Porosity Cutoff or Effective Pore Volume		km <sup>3</sup>	135	422	790
Effective-to-Total Porosity Percentage	$E_{\varphi_{eff}/\varphi_t}$		80%	83%	97%
Effective-to-Total Pore Volume Percentage	$E_{geol}$		18%	33%	44%

**Table 5. Saline Formation Displacement Efficiency Terms,  $E_D$  (U.S. Department of Energy, 2010)**

Lithology	P10	P50	P90
Clastics	7.4%	14%	24%
Dolomites	16%	21%	26%
Limestones	10%	15%	21%

**Table 6. Effective Storage Efficiency Factors and Resulting Effective Storage Resource for the P10, P50, and P90 Upper Minnelusa Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Pore Volume	$V_{PV}$	km <sup>3</sup>	153	174	212
Effective-to-Total Pore Volume Ratio	$E_{geol}$		40%	45%	47%
Volumetric Displacement Efficiency	$E_D$		7.4%	14%	24%
Effective Storage Efficiency Factor	$E_E$		2.9%	6.3%	11%
Effective Storage Volume		km <sup>3</sup>	4.48	11	23.7
Average CO <sub>2</sub> Density	$\rho_{CO_2}$	kg/m <sup>3</sup>	773*	773*	773*
Effective CO <sub>2</sub> Storage Mass	$M_{CO_2,E}$	Mt**	3466	8519	18,282

\* CO<sub>2</sub> density was calculated at average reservoir properties of 33.6 MPa and 81°C.

\*\* Million tonnes.

**Table 7. Effective Storage Efficiency Factors and Resulting Effective Storage Resource for the P10, P50, and P90 Qingshakou–Yaojia Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Pore Volume	$V_{PV}$	km <sup>3</sup>	742	1290	1810
Effective-to-Total Pore Volume Ratio	$E_{geol}$		18%	33%	44%
Volumetric Displacement Efficiency	$E_D$		7.4%	14%	24%
Effective Storage Efficiency Factor	$E_E$		1.3%	4.6%	10%
Effective Storage Volume		km <sup>3</sup>	10	59.1	190
Average CO <sub>2</sub> Density	$\rho_{CO_2}$	kg/m <sup>3</sup>	680*	680*	680*
Effective CO <sub>2</sub> Storage Mass	$M_{CO_2,E}$	Mt	6792	40,138	128,840

\* CO<sub>2</sub> density was calculated at average reservoir properties of 15 MPa and 48°C.

**Table 8. Closed-System Compressibility Storage Efficiency Factors and Resulting Compressibility Storage Resource for the P10, P50, and P90 Upper Minnelusa Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Pore Volume	$V_{PV}$	km <sup>3</sup>	153	174	212
Water Compressibility*	$c_w$	1/kPa	4.13E-07	4.13E-07	4.13E-07
Pore Compressibility*	$c_p$	1/kPa	5.58E-07	5.58E-07	5.58E-07
Initial Pressure	$P_0$	kPa	28,032	28,032	28,032
Maximum Pressure**	$P_{max}$	kPa	33,638	33,638	33,638
Percent Pore Volume from Compressibility	$E_{comp}$		0.54%	0.54%	0.54%
Compressible Reservoir CO <sub>2</sub> Storage Volume	$V_{CO_2,comp}$	km <sup>3</sup>	.831	.949	1.15
Average CO <sub>2</sub> Density Max	$\rho_{max}$	kg/m <sup>3</sup>	773	773	773
Compressible Reservoir CO <sub>2</sub> Storage Mass	$M_{CO_2,comp}$	Mt	643	733	891

\* Obtained from Liu and Li (2013), Brady and Lee (1998), and Pitts (2005).

\*\* Maximum allowable injection pressure was determined by adding 20% to the initial pressure.

**Table 9. Closed-System Compressibility Storage Efficiency Factors and Resulting Compressibility Storage Resource for the P10, P50, and P90 Qingshankou–Yaojia System Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Pore Volume	$V_{PV}$	km <sup>3</sup>	742	1290	1810
Water Compressibility*	$c_w$	1/kPa	3.93E-07	3.93E-07	3.93E-07
Pore Compressibility*	$c_p$	1/kPa	4.50E-07	4.50E-07	4.50E-07
Initial Pressure	$P_0$	kPa	12,542	12,542	12,542
Maximum Pressure**	$P_{max}$	kPa	15,051	15,051	15,051
Percent Pore Volume from Compressibility	$E_{comp}$		0.21%	0.21%	0.21%
Compressible Reservoir CO <sub>2</sub> Storage Volume	$V_{CO_2,comp}$	km <sup>3</sup>	1.57	2.73	3.82
Average CO <sub>2</sub> Density Max	$\rho_{max}$	kg/m <sup>3</sup>	680	680	680
Compressible Reservoir CO <sub>2</sub> Storage Mass	$M_{CO_2,comp}$	Mt	1067	1852	2597

\* Obtained from Zhao and others (2012), Esken and others (2012), and Zhang and others (2005).

\*\* Maximum allowable injection pressure was determined by adding 20% to the initial pressure.

## DYNAMIC EFFECTIVE CO<sub>2</sub> STORAGE RESOURCE ESTIMATION

The results of the volumetric effective CO<sub>2</sub> storage resource estimate indicate that if the upper Minnelusa Formation acts as an open system, then it should have approximately 3466 to 18,282 million tonnes of effective CO<sub>2</sub> storage resource potential or 2.9% to 11% efficiency. If the upper Minnelusa Formation acts as a closed system, then the resulting effective CO<sub>2</sub> storage resource potential would be approximately 643 to 891 million tonnes of effective CO<sub>2</sub> storage resource potential or about 0.54% efficiency. Likewise, the results indicate that the Qingshankou–Yaojia system should have approximately 6792 to 128,840 million tonnes of effective CO<sub>2</sub> storage resource potential or 1.3% to 10% efficiency, if it behaves as an open system and approximately 1067 to 2597 million tonnes of effective CO<sub>2</sub> storage resource potential or 0.21% efficiency if it behaves as a closed system. As a means of testing whether or not these two storage systems are open, closed, or semiclosed, dynamic reservoir simulations were performed on each model. Simulations were performed on the high, mid, and low pore volume realizations for each model, followed by simulation runs using optimization techniques. A total of twelve simulation cases were run for both the upper Minnelusa and Qingshankou–Yaojia models to investigate the effects of boundary conditions, well configurations, and injection and extraction strategies (Table 10).

In each simulation run, the entire formation extent within the upscaled geocellular models was used in order to better understand the pressure buildup effects. The overlying seals were also included in the models and assigned porosity, permeability, etc., from the literature. Initially, each case had injection for 50 years, with a 50-year postinjection period to observe pressure transient in the formations. The simulation runs were given wells according to the python script previously described, which selected the optimal location and perforation for each well

(Figures 11 and 12). As a result, each geologic model had a different number of wells, well

**Table 10. Simulation Cases and Simulation Notes**

Simulation Cases	Notes
1 – P10 Actual Boundary Conditions	Testing geologic sensitivity
2 – P50 Actual Boundary Conditions	Base run for comparison
3 – P90 Actual Boundary Conditions	Testing geologic sensitivity
4 – P50 Closed Boundaries	Testing boundary conditions
5 – P50 Open Boundaries	Testing boundary conditions
6 – P50 Half the Number of Vertical Injectors	Testing well configuration
7 – P50 Half the Number of Vertical Injectors and Extractors	Testing well configuration and extraction
8 – P50 Vertical Injection and Extractors	Testing well configuration and extraction
9 – P50 Horizontal Injectors	Testing the effect of horizontal wells
10 – P50 Horizontal Injectors and Vertical Extractors	Testing well configuration and extraction
11 – P50 Horizontal Injectors and Extractors	Testing well configuration and extraction
12 – P50 Double the Number of Vertical Injectors	Testing well configuration

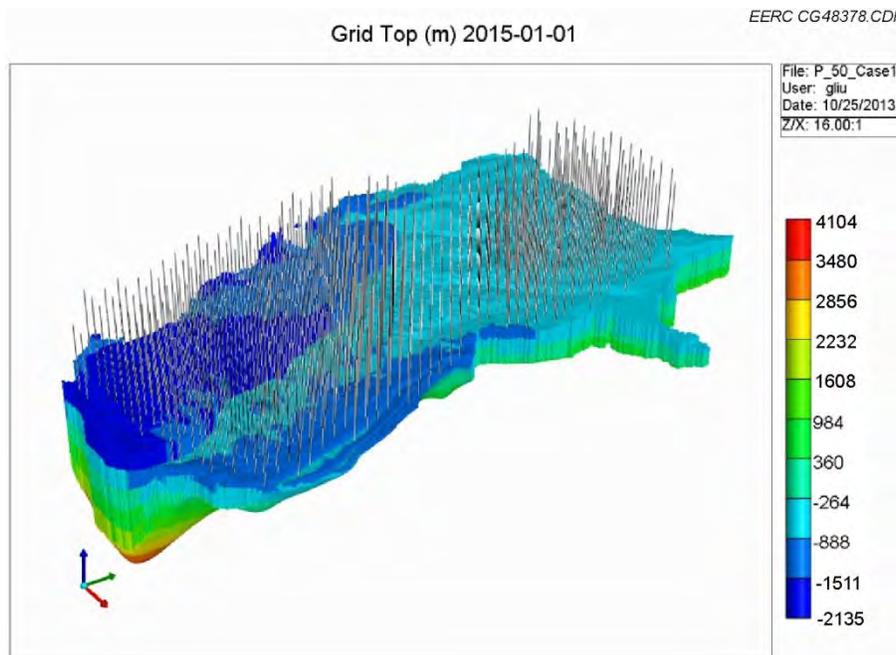


Figure 11. Upper Minnelusa Formation injection and extraction well locations.

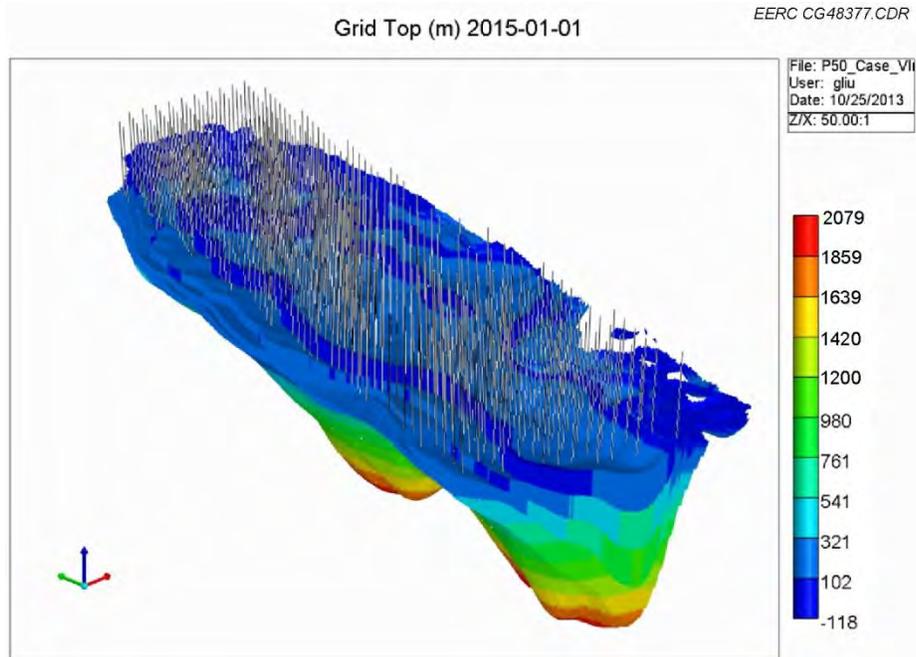


Figure 12. Qingshankou–Yaojia system injection and extraction well locations.

configurations, and perforated intervals. The well densities for each system for all simulation cases are shown in Table 11 and were approximately one to four wells per 200 km<sup>2</sup>, depending on the case. Rock and water compressibility were assigned to the upper Minnelusa and Qingshankou–Yaojia models from the literature and were the same values used in calculation of the closed-system effective storage efficiency (Tables 8 and 9). In each system, the initial pressure was determined from the literature and was roughly equal to the hydrostatic pressure. The maximum bottomhole pressure in each simulation case was determined by added 20% to the initial pressure. In addition, all simulation cases included CO<sub>2</sub> solubility and residual trapping. A full description of the simulation cases can be found in Appendix B.

The purpose of these injection simulations was not to determine the precise storage efficiency around an individual well; rather, the goal was to determine the effective storage efficiency by using a large group of wells injecting into a formation. As such, the actual CO<sub>2</sub> plume footprints were not estimated, and the main focus was on the pressure buildup in the formation and the pressure interference among wells. In the injection simulations, the actual effective dynamic CO<sub>2</sub> storage resource efficiency ( $E_E$ ) was determined by dividing the total mass of CO<sub>2</sub> injected by the total mass of CO<sub>2</sub>, which would occupy 100% of the pore space (if it were possible to completely fill 100% of the pore space with CO<sub>2</sub>) in the target formation. In addition, when the effective CO<sub>2</sub> storage resource potential is determined, it is also important to consider the physical and geochemical processes that take place through the injection process. These processes vary depending on the target, and in the case of storing CO<sub>2</sub> in entire formations through hundreds of injection wells, the primary short-term trapping mechanisms are physical and hydrodynamic. In these two storage scenarios, the hydrodynamic trapping will prevail, with

**Table 11. Well Density for Both Systems**

Cases	Minnelusa System				Qingshankou–Yaojia System			
	No. of Injection Wells	No. of Extraction Wells	Area, km <sup>2</sup>	Density, wells/km <sup>2</sup>	No. of Injection Wells	No. of Extraction Wells	Area, km <sup>2</sup>	Density, wells/km <sup>2</sup>
Case 1	462	NA	58,632	0.008	391	NA	45,995	0.009
Case 2	475	NA	58,632	0.008	432	NA	45,995	0.009
Case 3	492	NA	58,632	0.008	441	NA	45,995	0.010
Case 4	475	NA	58,632	0.008	432	NA	45,995	0.009
Case 5	475	NA	58,632	0.008	432	NA	45,995	0.009
Case 6	238	NA	58,632	0.004	216	NA	45,995	0.005
Case 7	238	237	58,632	0.008	216	216	45,995	0.009
Case 8	475	345	58,632	0.014	432	395	45,995	0.018
Case 9	475	NA	58,632	0.008	432	NA	45,995	0.009
Case 10	475	345	58,632	0.014	432	395	45,995	0.018
Case 11	475	345	58,632	0.014	432	395	45,995	0.018
Case 12	820	NA	58,632	0.014	827	NA	45,995	0.018

solubility trapping increasing as a result of the free-phase CO<sub>2</sub> contacting more unsaturated brine. Solubility trapping may play an important role in the storage resource potential of a target formation, especially if it occurs early in the project, decreasing the pressure buildup in the formation and increasing the amount of CO<sub>2</sub> that can be injected into the target reservoir. The effective CO<sub>2</sub> storage efficiency values that were developed as a result of this project take into account physical, hydrodynamic, solubility, and residual gas trapping. However, because of the complex nature of mineral trapping and the unknown factors associated with it, mineral trapping was not considered part of this project. As initially expected, the results of injection operations indicate that the two systems behave very differently; as such, the discussion of the simulation cases will be addressed individually.

### **Upper Minnelusa Formation Dynamic Simulation Results**

The results of the simulations after 50 years of injection operations for the upper Minnelusa Formation are shown in Table 12. After 50 years of injection, the cases with water extraction showed the highest increase in the storage efficiency, although the number of injection wells also seems to play an important role, indicating that Case 2 did not have enough wells and that local area pressure buildup due to injection may also be an important limiting factor in maximizing CO<sub>2</sub> storage in the first 50 years of injection.

At the end of the 50-year injection period, the upper Minnelusa Formation had not reached a maximum storage resource potential in any case, as was evident from the nearly linear increase in the cumulative storage over time in all of the injection cases (Figures 13a and 13b). To better determine the maximum effective CO<sub>2</sub> storage resource potential and efficiency in the upper Minnelusa Formation, several cases were run for an extended period of time, continuously injecting CO<sub>2</sub> to determine when the cumulative injection mass plateaued at an effective maximum storage. These long simulation runs produced logarithmic functions, with the cumulative CO<sub>2</sub> mass stored gradually leveling off in the first 1000 years of injection (Figure 14). In the rest of the cases without water extraction, the injected volumes were predicted by fitting a logarithmic function, to the data and extrapolating the results out to 2000 years (Figure 15). It is worth noting that some of the extrapolations likely over- or underestimate the long-term storage resource potential, as only 50 years of data was used to make these extrapolations. Cases 7, 8, 10 and 11 included water extraction and were not extrapolated out beyond the simulation data. This was decided because extrapolating cumulative maximum storage for these cases was difficult since it is likely that the storage resource potential would have continued to increase until CO<sub>2</sub> was produced at the extraction wells, causing them to shut in. However, it is assumed that the maximum would be higher in the simulation cases with water extraction than in cases without extraction, as demonstrated by the first 50 years of data. When the storage mass for each case (Table 13) and the accompanying effective CO<sub>2</sub> storage efficiency (Table 14) are examined over time and compared to the effective storage efficiency values from the volumetric assessment, it appears that the upper Minnelusa Formation behaves like an open system. After only 50 years of injection into the upper Minnelusa Formation, the dynamic effective storage efficiency was over 1% for all cases except for Case 6; however, none of the simulation runs had reached a maximum storage, as efficiencies in all of the cases were still

**Table 12. Upper Minnelusa Simulations Results after 50 years of Injection Operation**

Case	Injection Wells	Extraction Wells	Mass CO <sub>2</sub> Injected, Mt	E, %	Change from Case 2, %
1	462	NA*	1194	1.01	-19
2	475	NA	1674	1.24	0
3	492	NA	2143	1.31	5
4	475	NA	1613	1.20	-4
5	475	NA	1725	1.28	3
6	238	NA	742	0.55	-56
7	238	237	1177	0.88	-30
8	475	345	3238	2.41	93
9	475**	NA	1704	1.27	2
10	475**	345	3238	2.41	93
11	475**	345**	3774	2.81	125
12	820	NA	2250	1.67	34

\* Not applicable.

\*\* Indicates horizontal wells.

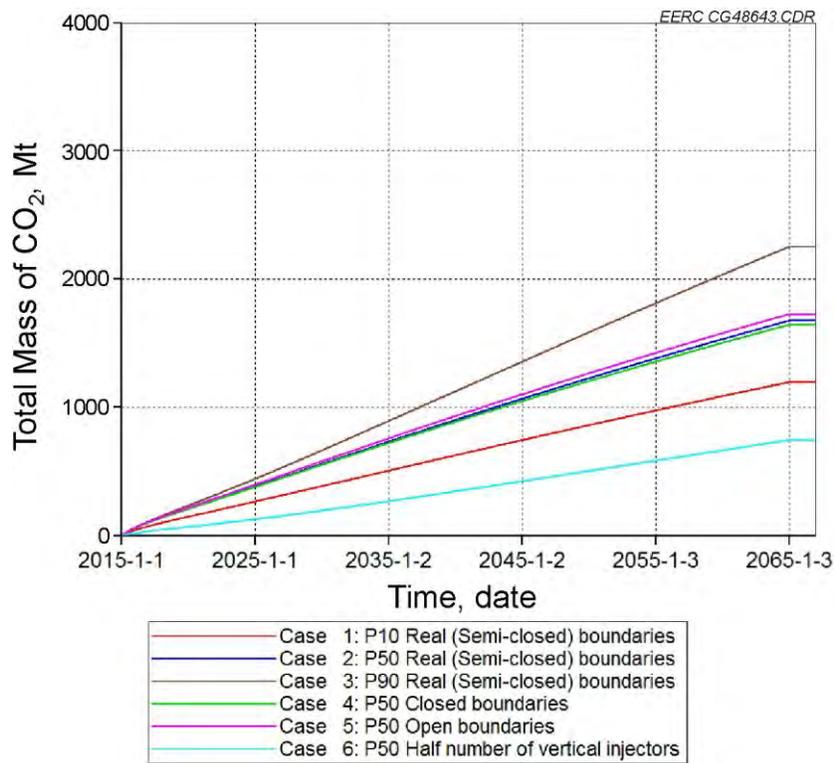


Figure 13a. Upper Minnelusa Formation simulation results (Cases 1–6), illustrating the nearly linear increase in the dynamic storage potential over time.

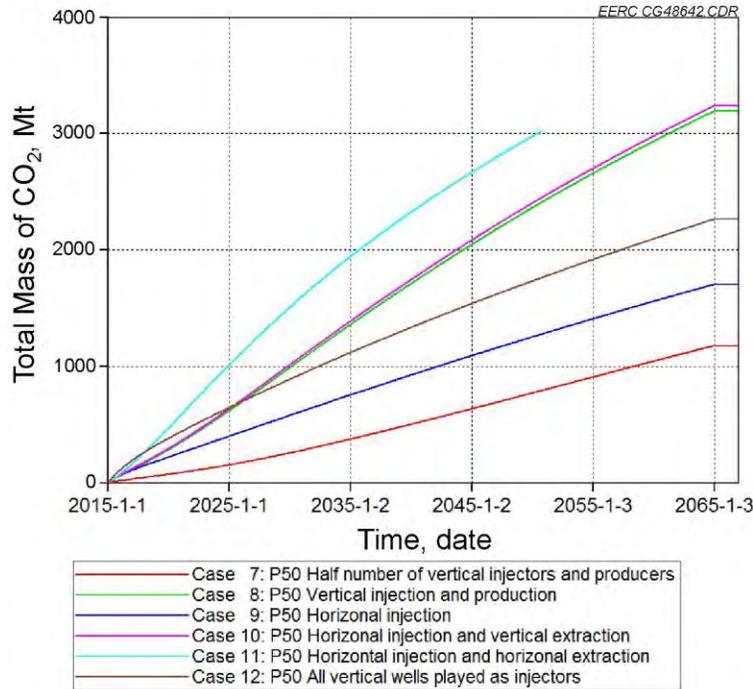


Figure 13b. Upper Minnelusa Formation simulation results (Cases 7–12), illustrating the nearly linear increase in the dynamic storage potential over time.

increasing in a nearly linear manner. When the simulations were run for longer periods of time or extrapolated out for the 2000 years of injection, the effective storage efficiency was in the same range as the volumetric estimates of 2.9% to 11% (Figure 16). If the upper Minnelusa were a closed or semiclosed system, the effective dynamic storage efficiency should have been approximately 0.54% (Table 8), and this was exceeded by all of the simulation cases in the first 50 years of injection operations.

### Qingshankou–Yaojia System Dynamic Simulation Results

The results of the simulations after 50 years of injection operations for the Qingshankou–Yaojia system are shown in Table 15. The results of these simulation runs indicate that pressure buildup in the formations plays the biggest role in determining the cumulative amount of CO<sub>2</sub> injected. This is evident by looking at the effective storage efficiency results without water extraction compared to those results with water extraction. In every case without water extraction, the effective storage efficiency varies by less than 25%; however, those cases which include water extraction (pressure maintenance) have effective storage efficiency over 100% higher, indicating that pressure buildup is the most limiting factor in this case. All simulation cases considered CO<sub>2</sub> solubility and residual trapping.

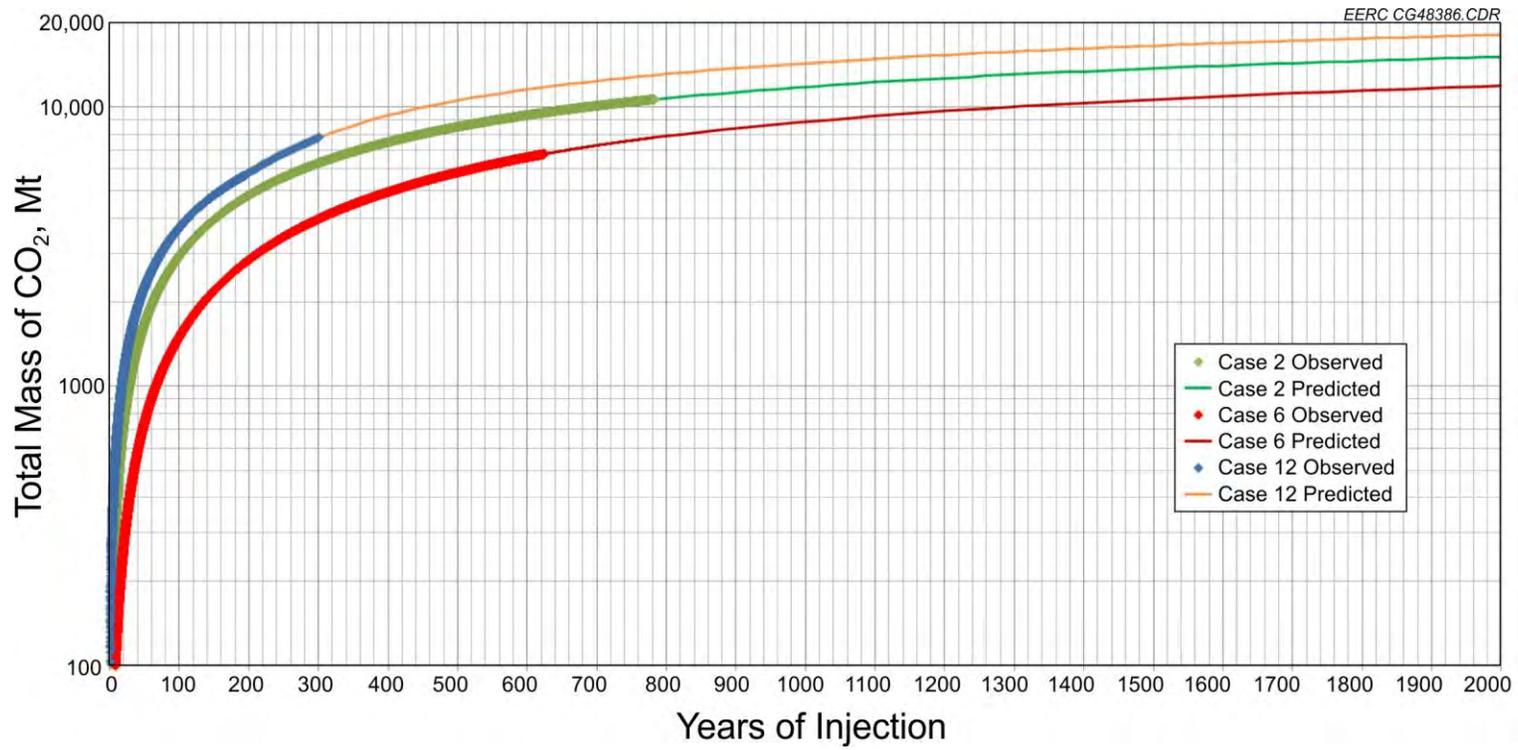


Figure 14. Long-period injection simulations in the upper Minnelusa Formation indicate that the effective storage mass in Cases 2, 6, and 12 level off very quickly after 300 years of injection.

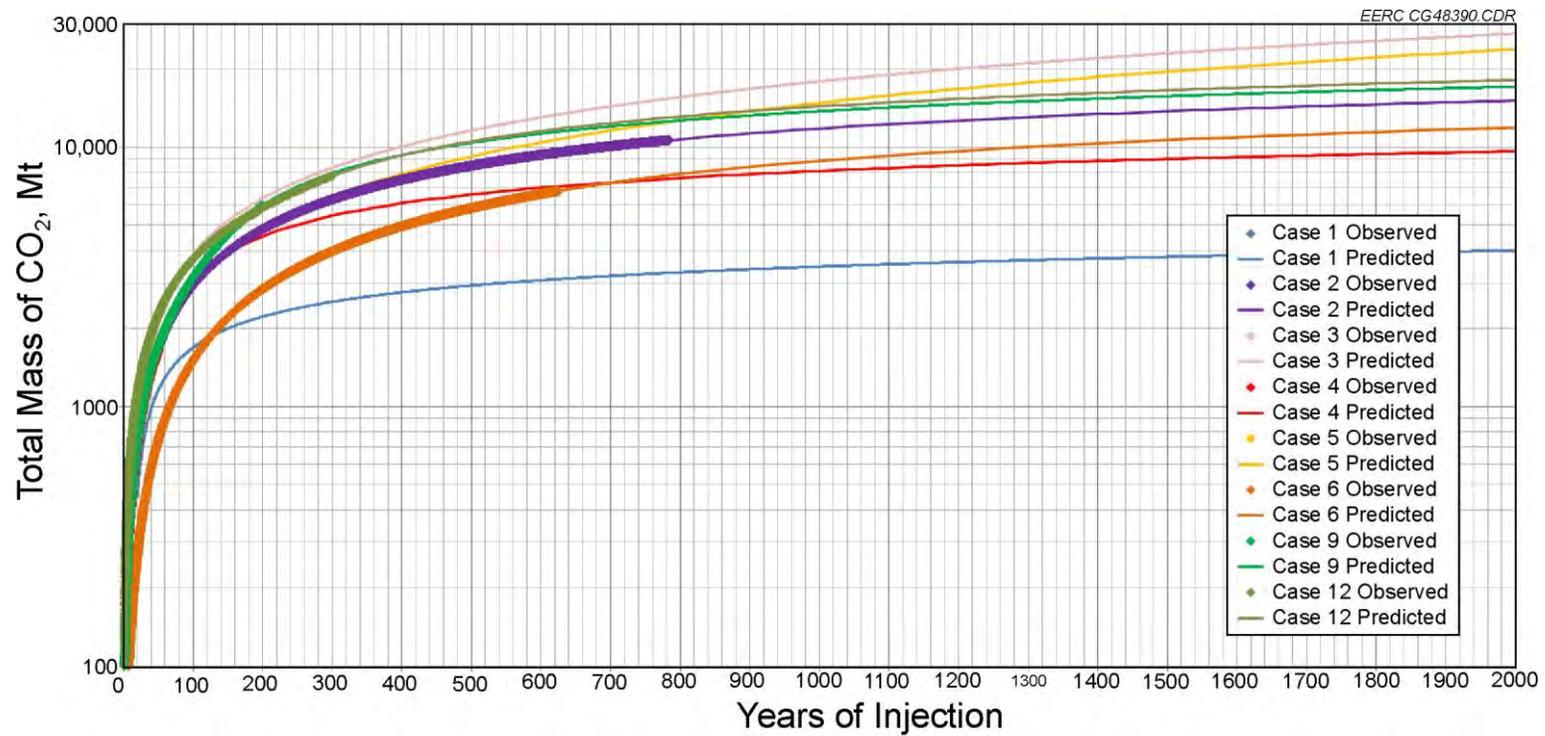


Figure 15. The cumulative mass of injected CO<sub>2</sub> levels off very quickly after the first 200 years of injection and shows little increase beyond 500 years of injection in the upper Minnelusa Formation.

**Table 13. Upper Minnelusa Formation Cumulative CO<sub>2</sub> Storage Mass over Time for the Simulation Cases Without Water Extraction, Mt**

Time, years	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 12
0	0	0	0	0	0	0	0	0
50	1193	1672	2248	1641	1724	742	1470	2263
100	1689	2928	3873	3007	3056	1504	2389	3698
200	2223	4830	6348	4544	4916	2838	3124	5826
500	2931	8491	11,626	6576	9218	5830	4097	10,558
1000	3464	11,662	17,933	8112	14,830	8417	4829	14,363
2000	3998	14,786	27,412	9649	23,859	10,867	5563	18,168

**Table 14. Upper Minnelusa Formation Effective CO<sub>2</sub> Storage Coefficients over Time for the Simulation Cases Without Water Extraction**

Time, years	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 12
0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
50	1.01%	1.24%	1.37%	1.22%	1.28%	0.55%	1.09%	1.68%
100	1.43%	2.18%	2.36%	2.24%	2.27%	1.12%	1.78%	2.75%
200	1.88%	3.59%	3.87%	3.38%	3.65%	2.11%	2.32%	4.33%
500	2.48%	6.31%	7.09%	4.89%	6.85%	4.33%	3.05%	7.85%
1000	2.93%	8.67%	10.94%	6.03%	11.03%	6.26%	3.59%	10.68%
2000	3.38%	10.99%	16.73%	7.17%	17.74%	8.08%	4.14%	13.51%

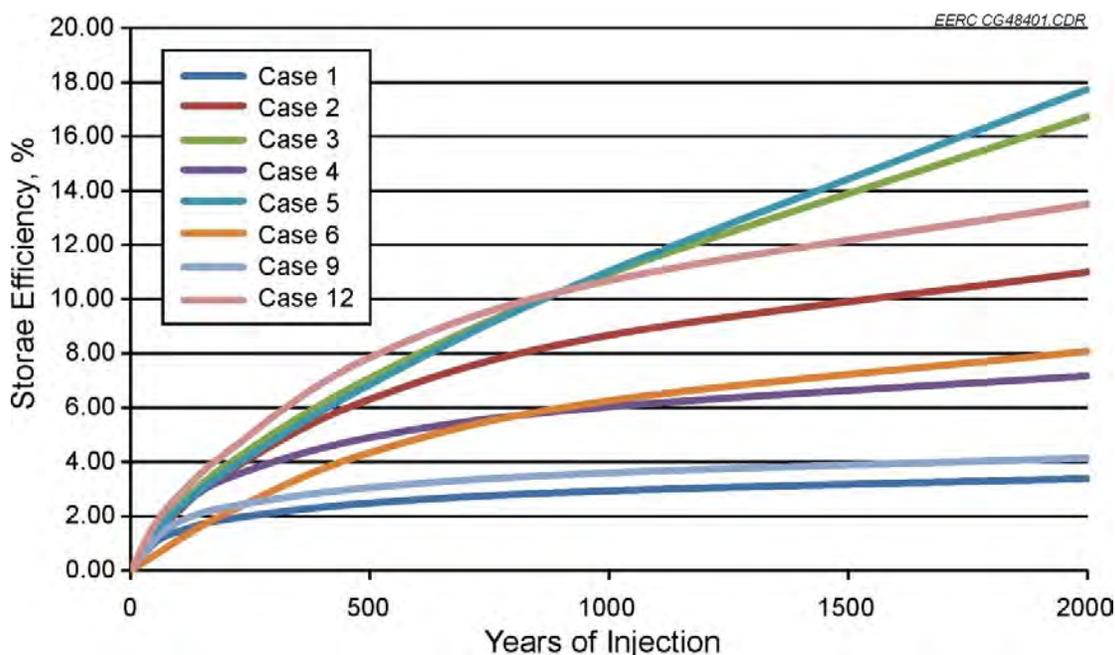


Figure 16. The effective CO<sub>2</sub> storage efficiency in the upper Minnelusa Formation rises fairly linearly for the first couple of hundred years and then increases more slowly in the long term.

**Table 15. Qingshankou–Yaojia System Simulations Results after 50 years of Injection Operation**

Case	Injection Wells	Extraction Wells	Mass CO <sub>2</sub> Injected, Mt	E, %	Change from Case 2, %
1	391	NA*	1402	0.28	-21
2	432	NA	3067	0.35	0
3	441	NA	4917	0.40	14
4	432	NA	2975	0.34	-3
5	432	NA	3222	0.37	5
6	216	NA	2578	0.29	-16
7	216	216	8297	0.95	171
8	432	395	17,281	1.97	463
9	432**	NA	3158	0.36	3
10	432**	395	17,487	1.99	470
11	432**	395**	17,625	2.01	475
12	827	NA	3312	0.38	8

\* Not applicable.

\*\* Indicates horizontal wells.

At the end of the 50-year injection period, the Qingshankou–Yaojia system had not reached a maximum storage resource potential in all cases, as is evident from the continued increase in the cumulative storage in all of the injection cases, although the rate of increase in the cumulative storage amount did begin to decrease by the end of 50 years of injection in most cases because of pressure buildup (Figures 17a and 17b). In order to determine the maximum effective storage resource in the Qingshankou–Yaojia system, several cases were run for 2000 years, continuously injecting CO<sub>2</sub> to determine when the cumulative injection mass plateaued at an effective maximum storage. These long simulation runs produced logarithmic functions, with the cumulative CO<sub>2</sub> mass stored dropping off quickly after 100 years of injection (Figure 18). In the rest of the cases without water extraction, the injected volumes were predicted by fitting a logarithmic function to the data and extrapolating the results out to 2000 years (Figure 19). Cases 7, 8, 10 and 11 contained water extraction and were not extrapolated out beyond the simulation data as it was difficult to make any future extrapolations about the cumulative maximum storage; however, it is assumed that the maximum would be much higher than cases without extraction, as demonstrated by the first 50 years of data. When the storage mass for each case (Table 16) and the accompanying effective CO<sub>2</sub> storage efficiency values (Table 17) are examined over time and compared to the effective storage efficiency values from the volumetric assessment, it appears that the Qingshankou–Yaojia system behaves like a closed or semiclosed system. If the formation were an open system, then the effective storage coefficients should be approximately 1.3% for the P10 realizations, 4.6% for the P50 realizations, and 10% for the P90 realizations (Table 7). In all of the simulation cases without water extraction, the effective storage efficiency was less than 1% even after 2000 years of injection operations, and the increase in the efficiency starts to plateau after the first 100 years (Figure 20).

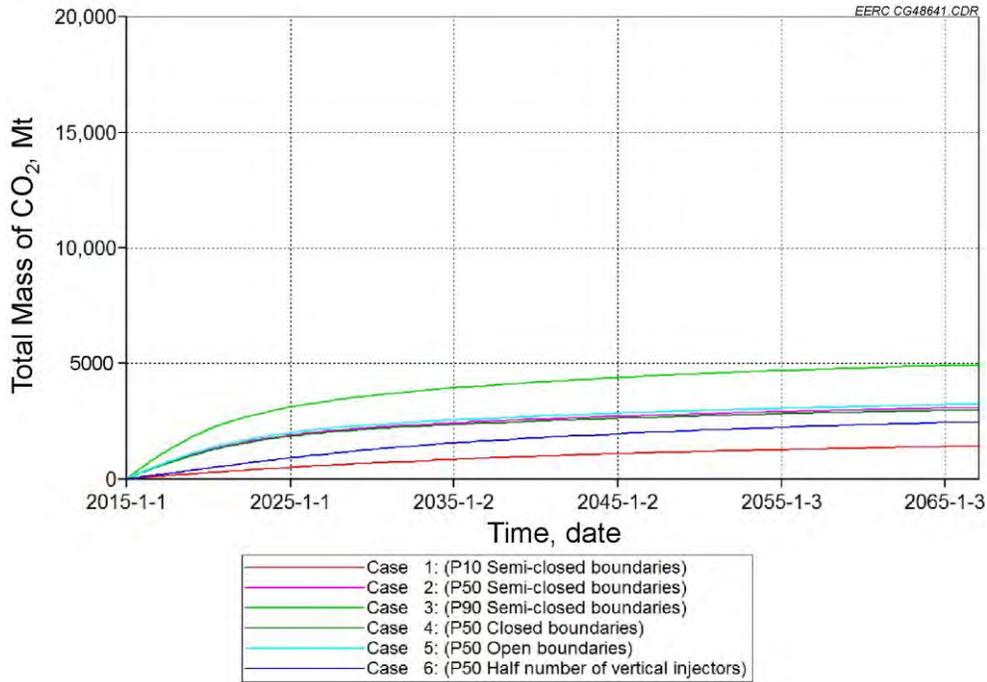


Figure 17a. Qingshankou–Yaojia system simulation results (Cases 1–6), illustrating the slow increase in the dynamic storage potential over time.

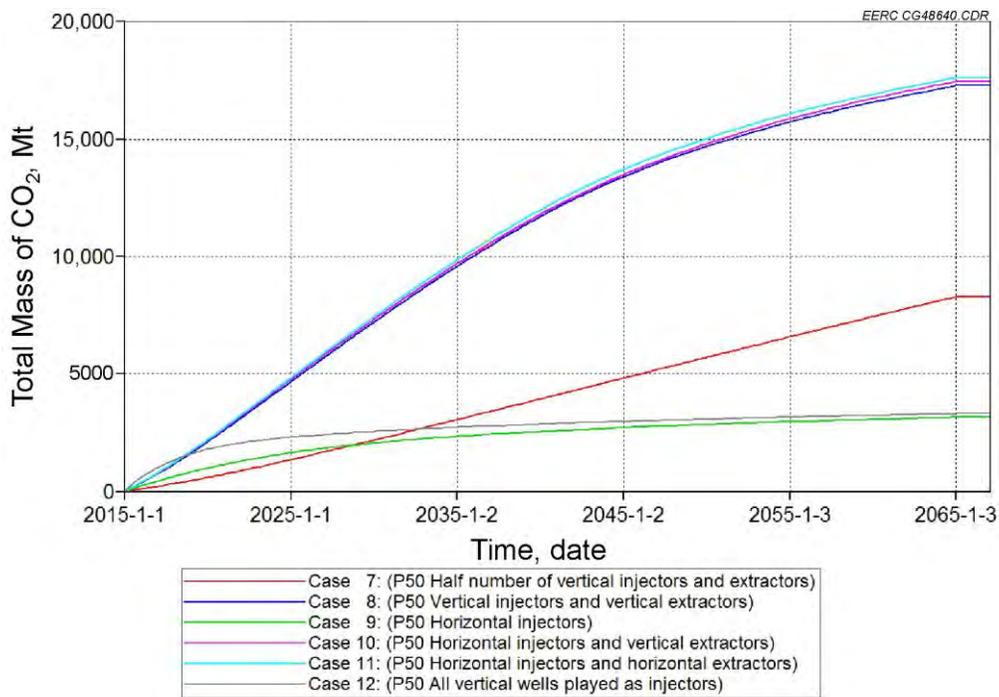


Figure 17b. Qingshankou–Yaojia system simulation results (Cases 7–12), illustrating the slow increase in the dynamic storage potential over time.

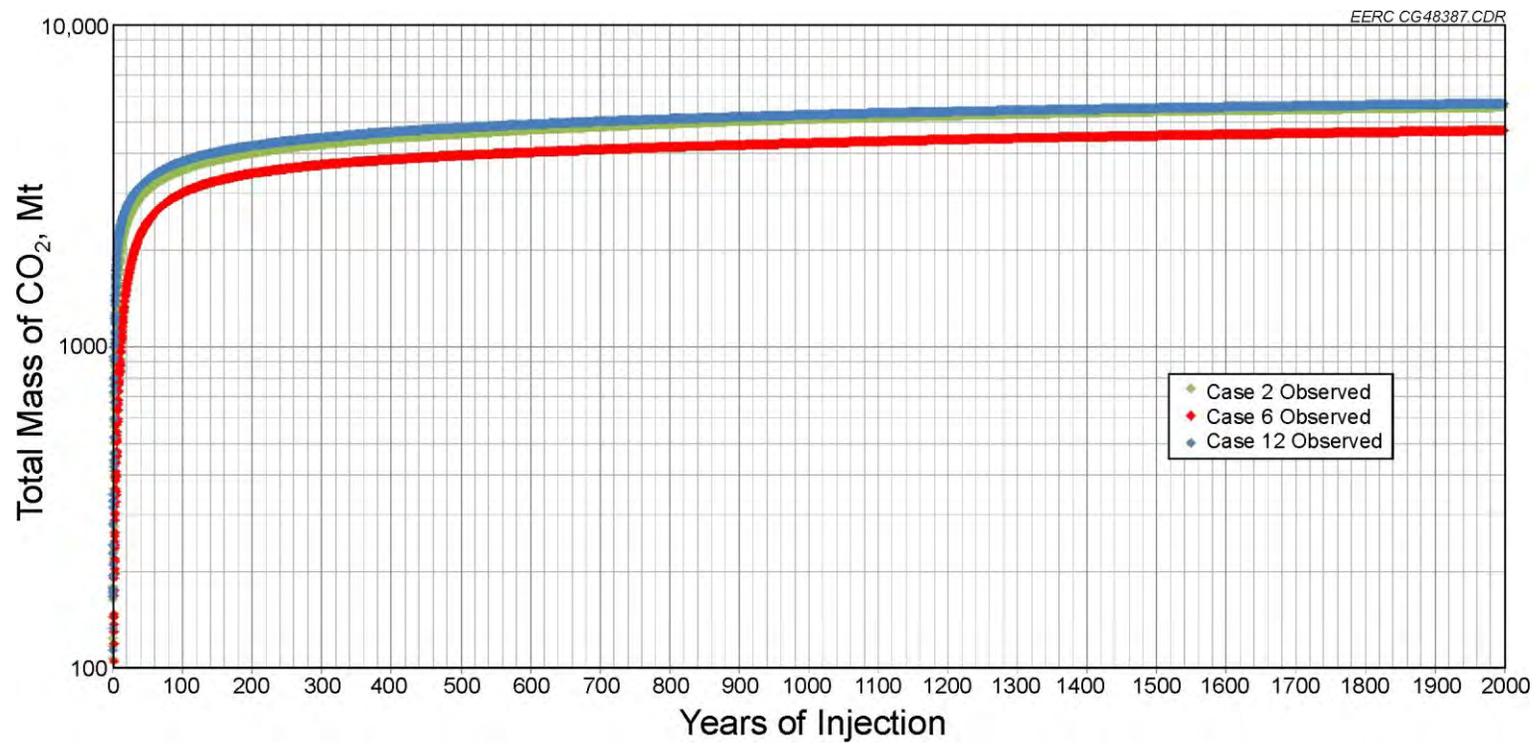


Figure 18. Long-period injection simulations in the Qingshankou–Yaojia system indicate that the effective storage mass in Cases 2, 6, and 12 drops off very quickly after 100 years of injection.

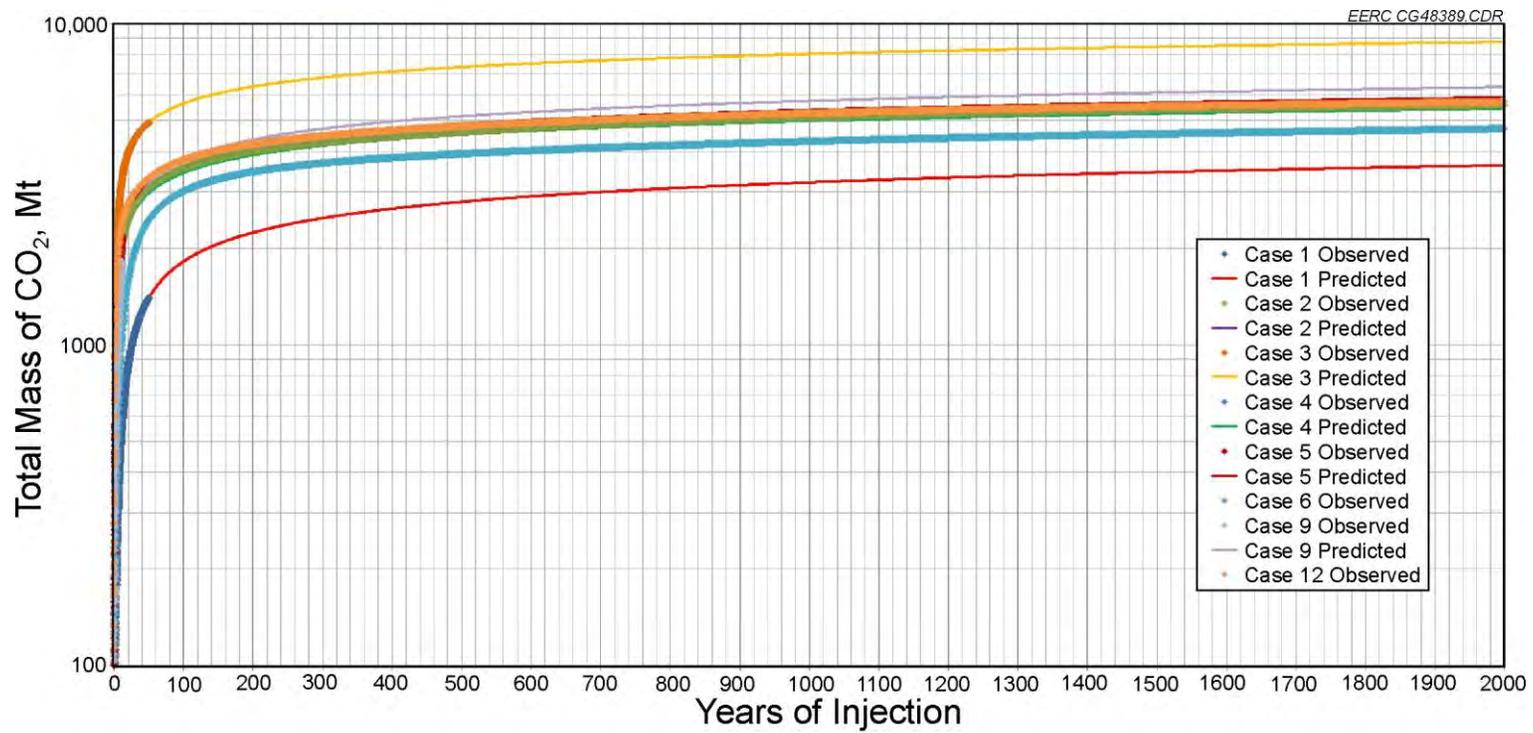


Figure 19. The cumulative mass of injected CO<sub>2</sub> drops off very quickly after the first 50 years of injection and shows little increase beyond 500 years of injection in the Qingshankou–Yaojia system.

**Table 16. Qingshankou–Yaojia System Cumulative CO<sub>2</sub> Storage Mass over Time for the Simulation Cases Without Water Extraction, Mt**

Time, years	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 12
0	0	0	0	0	0	0	0	0
50	1402	3066	4917	2974	3221	2448	3158	3312
100	1820	3547	5648	3437	3721	3010	3759	3772
200	2237	4005	6371	3900	4222	3459	4358	4220
500	2788	4605	7328	4513	4885	3936	5149	4803
1000	3205	5107	8050	4977	5386	4305	5747	5266
2000	3622	5578	8774	5441	5888	4711	6346	5713

**Table 17. Qingshankou–Yaojia System Effective CO<sub>2</sub> Storage Coefficients over Time for the Simulation Cases Without Water Extraction**

Time, years	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 12
0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
50	0.28%	0.35%	0.40%	0.34%	0.37%	0.28%	0.36%	0.38%
100	0.36%	0.40%	0.46%	0.39%	0.42%	0.34%	0.43%	0.43%
200	0.44%	0.46%	0.52%	0.44%	0.48%	0.39%	0.50%	0.48%
500	0.55%	0.52%	0.60%	0.51%	0.56%	0.45%	0.59%	0.55%
1000	0.64%	0.58%	0.65%	0.57%	0.61%	0.49%	0.66%	0.60%
2000	0.72%	0.64%	0.71%	0.62%	0.67%	0.54%	0.72%	0.65%

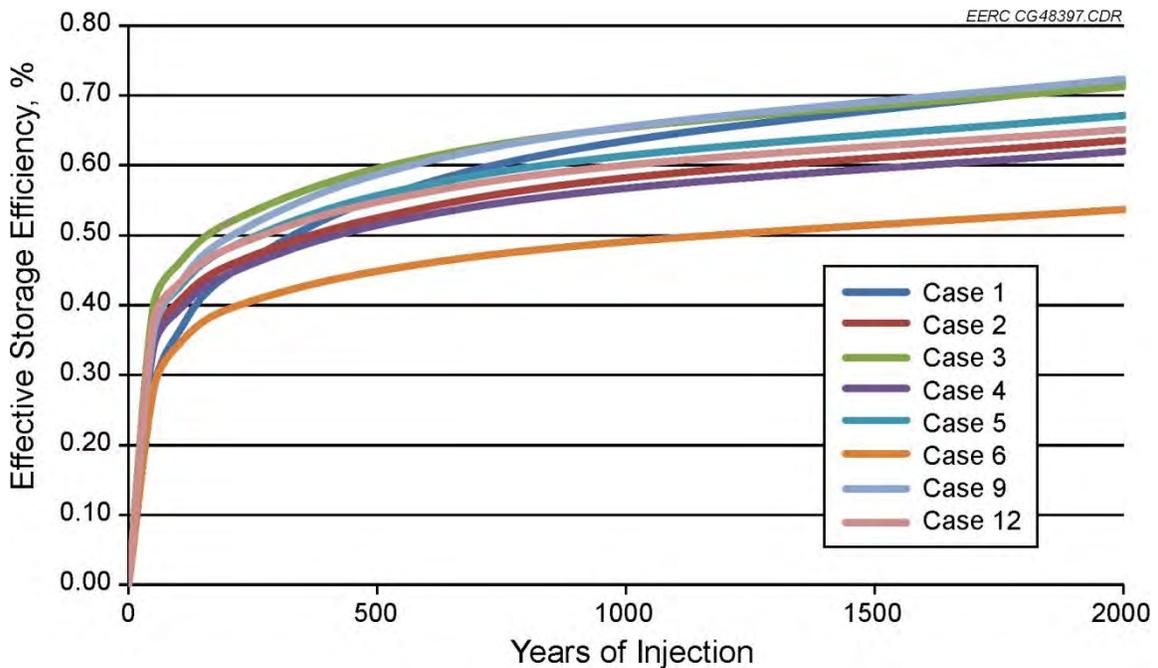


Figure 20. The effective storage efficiency in the Qingshankou–Yaojia system rises quickly, and then all cases begin to plateau after the first 100 years of injection.

## DISCUSSION OF SIMULATION RESULTS

The following sections discuss in detail the various factors affecting dynamic effective CO<sub>2</sub> storage resource estimates that were investigated in this study. These factors include geologic CO<sub>2</sub> storage trapping mechanisms, geologic uncertainty and heterogeneity, formation boundary conditions, the number and types of wells, and storage optimization through water extraction. In addition, these factors and the resulting dynamic effective CO<sub>2</sub> storage resource potentials were also compared to the volumetric effective CO<sub>2</sub> resource potentials, and conclusions were drawn based on the comparison.

### Trapping Mechanisms

As previously mentioned, it is expected that different trapping mechanisms will play different roles in trapping CO<sub>2</sub> in the reservoir throughout the life of the storage project. However, in this study, the main concern was with how these trapping mechanisms affect the effective CO<sub>2</sub> storage resource potential and efficiency. In the simulations previously described, physical, hydrodynamic, residual gas, and solubility trapping were utilized to understand the effective CO<sub>2</sub> storage resource potential of the target formations. Over time, the trapping mechanisms lock CO<sub>2</sub> in the reservoir and gradually decrease the amount of remaining storage potential. This principle holds true for all the mechanisms except solubility trapping. As injected CO<sub>2</sub> mixes with the native formation waters, a portion of the CO<sub>2</sub> dissolves into the water, increasing its density, and the CO<sub>2</sub> takes up less space when dissolved, thus decreasing the formation pressure and allowing more CO<sub>2</sub> to be stored in the same area (Ennis-King and Paterson, 2005). This dissolution process is a function of not only temperature, pressure, and salinity but also the mixing rate of the fluids. In reservoir simulations, the rate of mixing may be dependent on the grid size utilized for the simulations, with larger cells overestimating the rate of mixing, thus allowing more CO<sub>2</sub> to go into solution earlier than is likely to happen in an actual injection project. With that said, injection wells were placed throughout each target formation based on whether or not the geologic properties were amenable to CO<sub>2</sub> injection. As a result, most of the injection occurred in areas without a significant local structural or stratigraphic trap, allowing the CO<sub>2</sub> to be more mobile and potentially contact more of the unsaturated formation waters.

In the upper Minnelusa Formation simulations, the amount of CO<sub>2</sub> dissolved in each case varied but was less than 25% in all cases after the first 50 years of injection simulation. As discussed earlier, this amount may be an overestimation because of the large cells in the simulation grid that was used and, if so, may overestimate the total amount of CO<sub>2</sub> that could be stored in the upper Minnelusa Formation. If the mass of CO<sub>2</sub> that was trapped in solution were removed from the total mass stored, the resulting dynamic effective CO<sub>2</sub> storage efficiencies would be reduced (Table 18). The results from the upper Minnelusa Cases 2, 6, and 12 were plotted to determine the percentage of CO<sub>2</sub> that is dissolved in the formation water over 500 years of injection (Figure 21). These results indicate that the percentage of CO<sub>2</sub> trapped in these cases remains roughly constant over this time period. It is also worth noting that the percentage of CO<sub>2</sub> in solution also correlates well with the number of injection wells used in the simulation. Cases 2, 6, and 12 had 475, 238, and 820 injection wells, respectively, and this

**Table 18. Upper Minnelusa Effective Storage Efficiency with and Without Dissolution after 50 years of Injection Operation**

Case	Mass CO <sub>2</sub> Injected, Mt	E, %	Mass CO <sub>2</sub> in Solution, Mt	Efficiency (E) Excluding CO <sub>2</sub> in Solution, %
1	1194	1.01	252	0.80
2	1674	1.24	348	0.98
3	2143	1.31	261	1.15
4	1613	1.20	344	0.94
5	1725	1.28	344	1.02
6	742	0.55	116	0.46
7	1177	0.88	207	0.73
8	3238	2.41	571	1.98
9	1704	1.27	357	1.00
10	3238	2.41	581	1.98
11	3774	2.81	950	2.10
12	2250	1.67	515	1.29

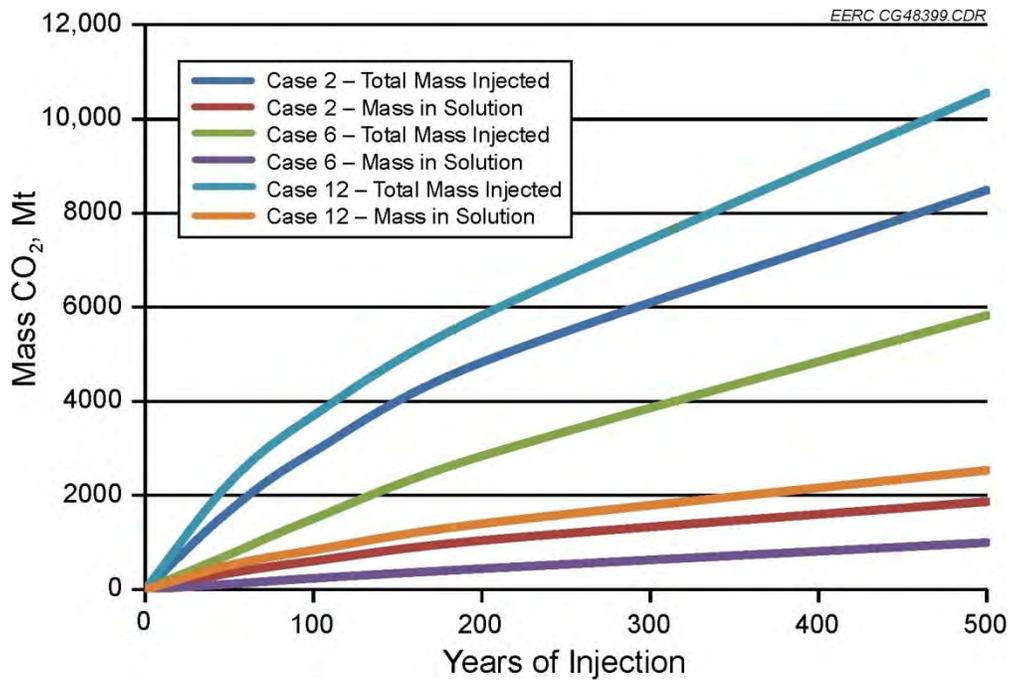


Figure 21. In the upper Minnelusa Formation simulation, CO<sub>2</sub> solubility trapping accounted for approximately 16% to 24% of the total CO<sub>2</sub> storage through the first 500 years of injection in these cases.

correlated to 22%, 16%, and 25% of the CO<sub>2</sub> in solution at the end of 500 years. This is likely due to more injection locations, creating more locations for unsaturated formation waters to mix with the injected CO<sub>2</sub>, increasing the overall solubility trapping effect.

In the case of the Qingshankou–Yaojia system, the amount of CO<sub>2</sub> dissolved in each simulation case was not insignificant, increasing quickly in the beginning of the project and then more slowly in the longer time periods. To further illustrate this point, the three cases from the Qingshankou–Yaojia system simulations were run for several thousand years, and then the mass of CO<sub>2</sub> injected and the mass of CO<sub>2</sub> in solution were plotted versus time (Figure 22). After the first 50 years of injection simulation, over 21% to 33% of the injected CO<sub>2</sub> is dissolved in the formation waters, and after 2000 years, this increased to 37% to 41%. Because of the complex fluid interactions involved in the convective mixing of CO<sub>2</sub> and the reservoir fluid, a fine-scaled model is needed to accurately simulate this effect. The simulation models used in this project had grid sizes too large to model this mixing with a high degree of accuracy. This may account for the small increase in dissolved CO<sub>2</sub> between 50 and 2000 years of injection, since the CO<sub>2</sub> does not contact many new grid cells after the first 50 years.

As previously mentioned, this increases the amount of CO<sub>2</sub> that can be injected into the formation because the dissolved CO<sub>2</sub> takes up much less space in the formation than the free-phase CO<sub>2</sub>. In the cases where water extraction is used, mixing between the injected CO<sub>2</sub> and unsaturated formation water increases, further enhancing this effect and increasing the storage efficiency. If CO<sub>2</sub> solubility trapping were not included in the dynamic effective CO<sub>2</sub> storage

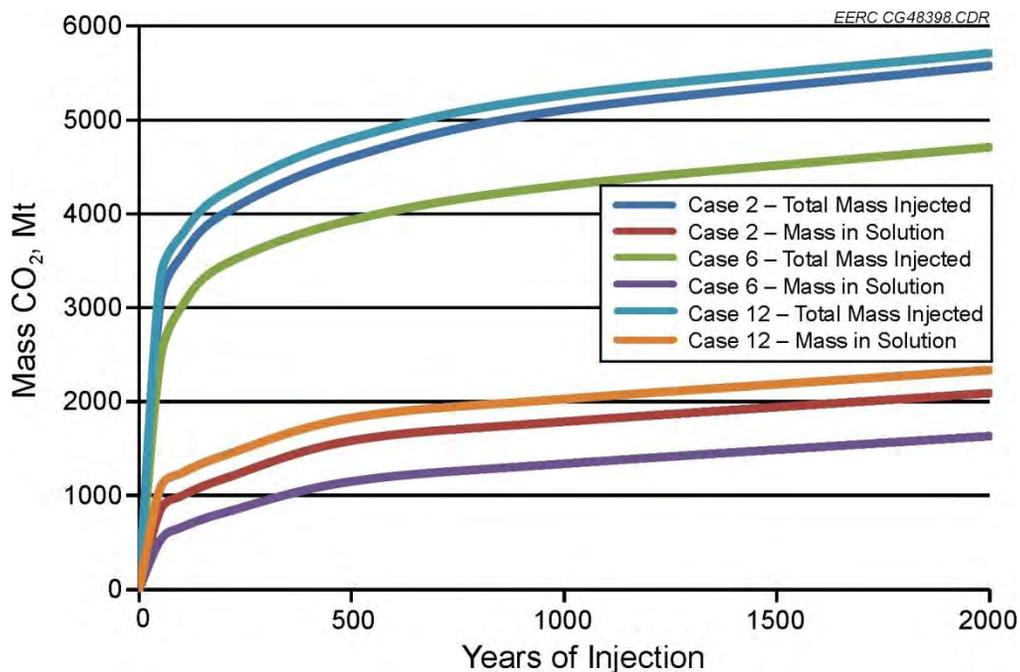


Figure 22. In the Qingshankou–Yaojia system, simulation CO<sub>2</sub> solubility trapping played a large role in CO<sub>2</sub> storage, and based on these three cases, solubility trapping accounted for approximately one-third of the total CO<sub>2</sub> storage.

efficiency calculations, the results would be less and are included in Table 19. Based on the simulation results for both the upper Minnelusa and Qingshankou–Yaojia models, it is expected that over time the contribution of solution trapping on storage efficiency will increase, potentially up to 50% of the effective storage potential after 2000 years of injection.

It is difficult to determine whether or not the amount of dissolution trapping in these cases is reasonable because of the grid size of the models. A very fine-scale model is needed to accurately model the convective mixing resulting from the injection of CO<sub>2</sub> into a reservoir. It is expected that the models used in this project artificially enhance this mixing early, resulting in the overestimation of CO<sub>2</sub> dissolution in the first 50 years and then a much smaller increase later as very little CO<sub>2</sub> contacts new grid cells. It was beyond the scope of this project to look specifically at the amount of CO<sub>2</sub> trapped as a result of dissolution; however, it is recommended based on the results of these simulations that the role of CO<sub>2</sub> solubility trapping on the effective CO<sub>2</sub> storage resource potential be investigated on a formation scale with multiple injectors to more accurately determine its effect on storage efficiency.

### Geologic Uncertainty

In order to evaluate the effects of geologic uncertainty and of different geologic realizations on the effective CO<sub>2</sub> storage efficiency, high (P90), mid (P50), and low (P10) pore volume cases were generated for both the upper Minnelusa and Qingshankou–Yaojia models. In the upper Minnelusa Formation, the variations in the geologic model resulted in the percentage of geology amenable to storage ( $E_{geol}$ ) ranging from 40% for the P10 to 47% for the P90 model realizations. This variability in the geology appears to play a significant role in the overall storage efficiency for the upper Minnelusa Formation, as the dynamic CO<sub>2</sub> storage efficiency ranges from 1.0% (P10) to 1.4% (P90) after 50 years and increases to 3.4% (P10) to 17% (P90) after 2000 years (Figure 23). These results indicate that the upper Minnelusa Formation is an

**Table 19. Qingshankou–Yaojia System Effective Storage Efficiency with and Without Dissolution after 50 years of Injection Operation**

Case	Mass CO <sub>2</sub> Injected, Mt	E, %	Mass CO <sub>2</sub> in Solution, Mt	Efficiency (E) Excluding CO <sub>2</sub> in Solution, %
1	1402	0.28	324	0.22
2	3067	0.35	845	0.25
3	4917	0.40	1428	0.28
4	2975	0.34	656	0.27
5	3222	0.37	888	0.27
6	2578	0.29	524	0.23
7	8297	0.95	1264	0.81
8	17,281	1.97	2780	1.65
9	3158	0.36	722	0.28
10	17,487	1.99	2835	1.67
11	17,625	2.01	2891	1.68
12	3312	0.38	1080	0.26

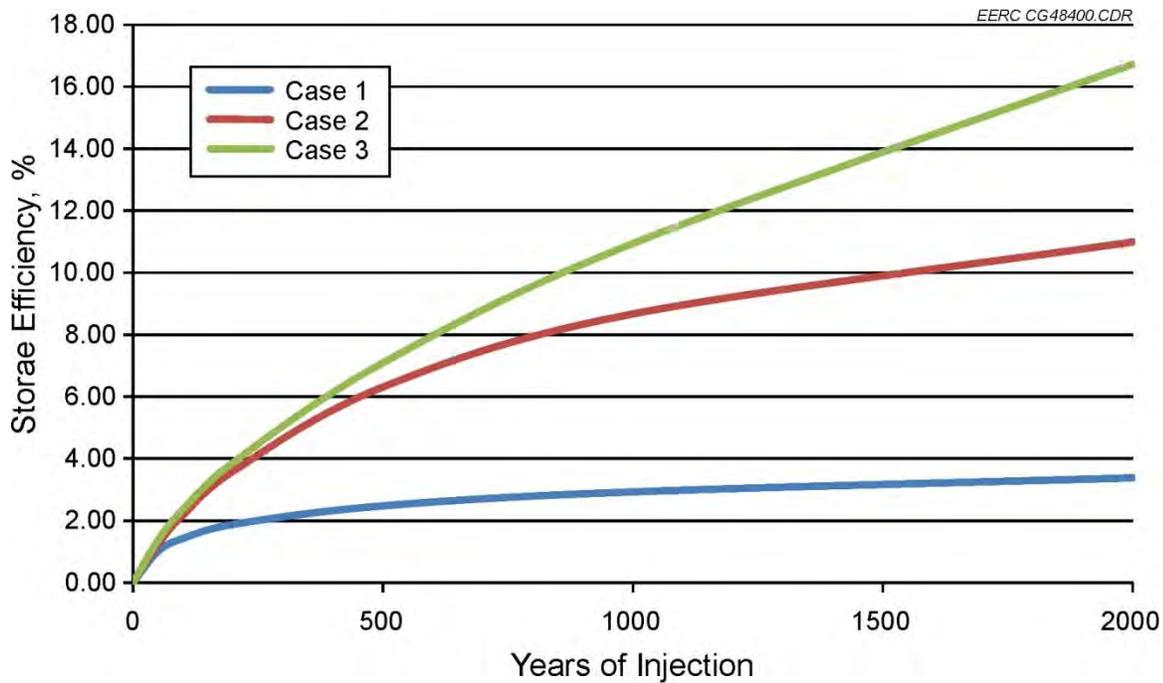


Figure 23. Effective CO<sub>2</sub> storage efficiency over time for the P10, P50, and P90 upper Minnelusa model geologic realizations.

open system, because although the dynamic injection simulations predict a slightly higher effective CO<sub>2</sub> storage efficiency, there is still very good agreement between the dynamic estimates and the estimates for the volumetric storage efficiency (i.e., 2.9% to 11%). This difference in storage efficiencies between the two methodologies may be due to the simulations overestimating the amount of CO<sub>2</sub> in solution (as previously discussed) and/or a poor prediction in particular for Case 3 (P90 geologic realization). In either case, the results from simulation indicate the upper Minnelusa is an open system and that both the volumetric and dynamic resource assessment methodologies will predict effective storage efficiencies that are roughly equivalent. Additionally, the results from the upper Minnelusa Formation show that geologic heterogeneity can have a strong effect on how efficiently an open system can store CO<sub>2</sub>.

In the Qingshankou–Yaojia system, the percentage of pore volume amenable to storage ranged from 18% for the P10 to 44% for the P90 model realizations. Even though the geologic heterogeneity was higher in these formations than the upper Minnelusa, the geologic variation did not appear to play as important a role. The results of the dynamic investigation on the Qingshankou–Yaojia system predicted dynamic storage efficiencies ranging from 0.28% to 0.40% after 50 years, increasing only slightly from 0.64% to 0.72% after 2000 years (Figure 24). The effective storage efficiency predicted from the volumetric assessment predicts 1.3% to 10% for open systems and 0.21% for closed systems. These results indicate that the Qingshankou–Yaojia system acts as a closed system or semiclosed system, since the values from simulation were much closer to those of the closed-system efficiency values, especially if the portion of the

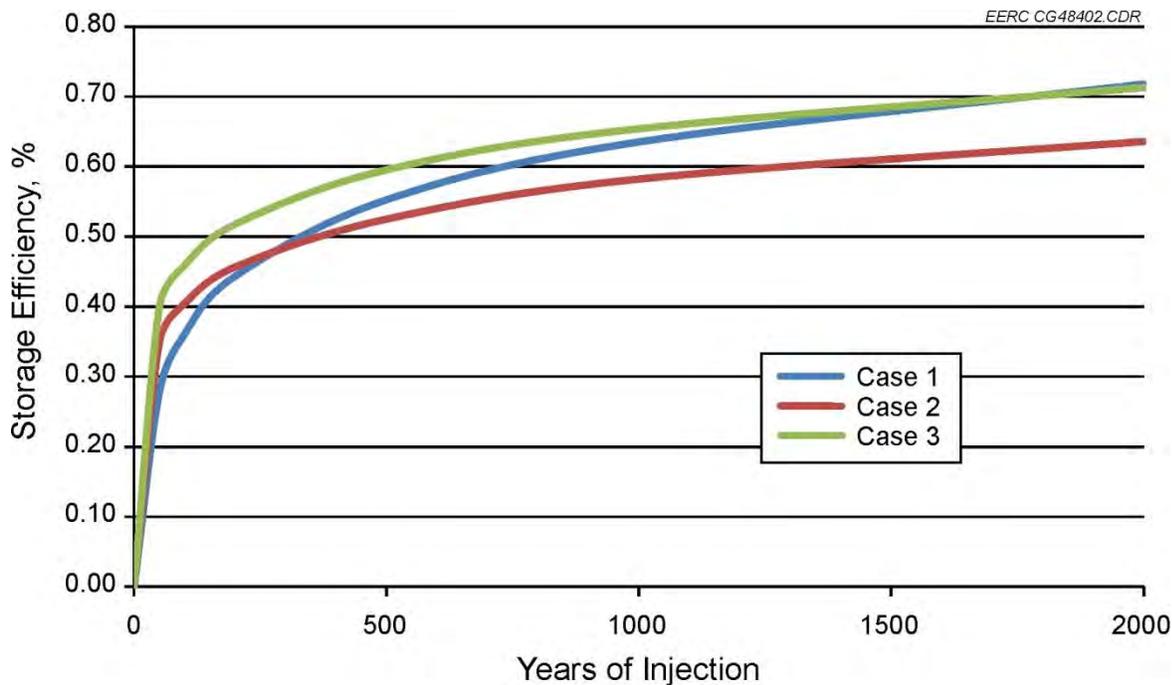


Figure 24. Effective CO<sub>2</sub> storage efficiency over time for the P10, P50, and P90 Qingshankou–Yaojia system model geologic realizations.

CO<sub>2</sub> in solution is removed from the calculation of the dynamic effective storage efficiency. Based on these results, volumetric estimates made on systems like this one should use a closed-system methodology to estimate the effective storage resource potential unless water extraction is utilized to increase the storage potential. Additionally, in a closed system, the geologic variability did not appear to play much of a role in the storage efficiency, as the P10 realization resulted in the highest effective storage efficiency in the Qingshankou–Yaojia system models; however, it is possible this is due to a poor prediction of the efficiency of the P10 case on the long time scales.

### Boundary Conditions

In the simulations presented in this study, the actual (Case 2), open (Case 5), and closed (Case 4) boundaries were used to thoroughly determine the impact of this variable on CO<sub>2</sub> storage resource potential and efficiency. To adequately model these types of systems, the dynamic simulations were run on geocellular models that included the entire formation extent and the overlying seals all the way to the surface. The inclusion of the overlying seals with representative permeability values may be one of the most important factors in determining whether or not the system behaves as open, closed, or semiclosed. A previous study by Permedia for the IEAGHG investigated the influence of the permeability of the formation seals on CO<sub>2</sub> storage capacity (IEAGHG, 2010). The study determined that if the permeability of the overlying seals was in the microdarcy range, formation waters could be displaced into the sealing formations at a high enough rate that the system would act as an open system while still preventing vertical migration of the injected CO<sub>2</sub> as a result of capillary forces. Alternatively, if the permeability of the formation seals

was in the nanodarcy range then the system would act in a closed manner, resulting in pressure-limited, or closed-system, behavior (IEA Greenhouse Gas R&D Programme, 2010).

In the simulation cases for both the upper Minnelusa and Qingshankou–Yaojia systems, the “actual” boundary conditions were defined by constructing the geocellular model to cover the entire formational extent, including areas too shallow to inject CO<sub>2</sub>; areas of discharge, recharge, and outcrops; and all of the overlying sealing formations to the surface. The overlying seals were assigned realistic porosity, permeability, and relative permeability values based on these formation types found in the literature. Next, constant pressure boundaries were assigned to the surface, as well as recharge, discharge, and outcrop areas. The lateral edges of the formations that terminated because of stratigraphic traps (e.g., pinch-outs or low-permeability rock) and structural traps (e.g., sealing faults) were assigned no-flow boundaries. The inclusion of these additional areas outside of those typically considered for injection in the model made it possible to assess whether the systems are open, closed, or semiclosed. The “open” boundary conditions were defined by taking the same model conditions described in the actual boundary conditions and adding infinite acting boundary conditions to all lateral edges of the formation—including those terminating deep in the subsurface and those that would otherwise be closed because of sealing faults or other features. In the reservoir simulation software, this was accomplished by assigning the same properties of the edge grid blocks out into an infinite system. A major limitation of this approach is that if the edge grid blocks have very low permeability and porosity, then the influence of even an infinite acting aquifer may be minimized. “Closed” boundaries were assigned the same as the actual boundary conditions except for assigning permeability to the overlying formations 100 times lower than the actual conditions case. This has the limitation that, if the permeability in the overlying seals was already in the nanodarcy range, the results would not look significantly different than the actual boundary conditions scenario, with both acting as closed systems.

For the upper Minnelusa simulation results, Cases 2 (actual boundaries), 4 (closed boundaries), and 5 (open boundaries) were used to evaluate whether or not the assigned boundary conditions affected the dynamic storage efficiency. During the first 50 years of injection, very little difference was seen between the effective storage efficiency, with results from all three cases between 1.22% and 1.28%; however, when the cases were predicted out to 2000 years, the results diverged, with efficiencies for the open (Case 5), actual (Case 2), and closed (Case 4) of 18%, 11%, and 7.2%, respectively (Figure 25). In none of the cases did the system behave as a closed system, with all cases acting as an open system to varying degrees. This is likely due to the strong influence that the recharge, discharge, and outcrop areas have in this particular case at relieving formation pressure. In addition, the permeability of the overlying seals in the actual and open boundary conditions cases increased the storage efficiency in the actual and open scenarios by 53% and 147%, respectively, illustrating the important role that the formation seals can play in influencing storage efficiency, even in open systems.

In the Qingshankou–Yaojia cases, changing the boundary conditions did little to affect the resulting storage efficiency after 50 and 2000 years. After 50 years of injection, the Qingshankou–Yaojia system’s boundary condition cases had effective storage efficiencies

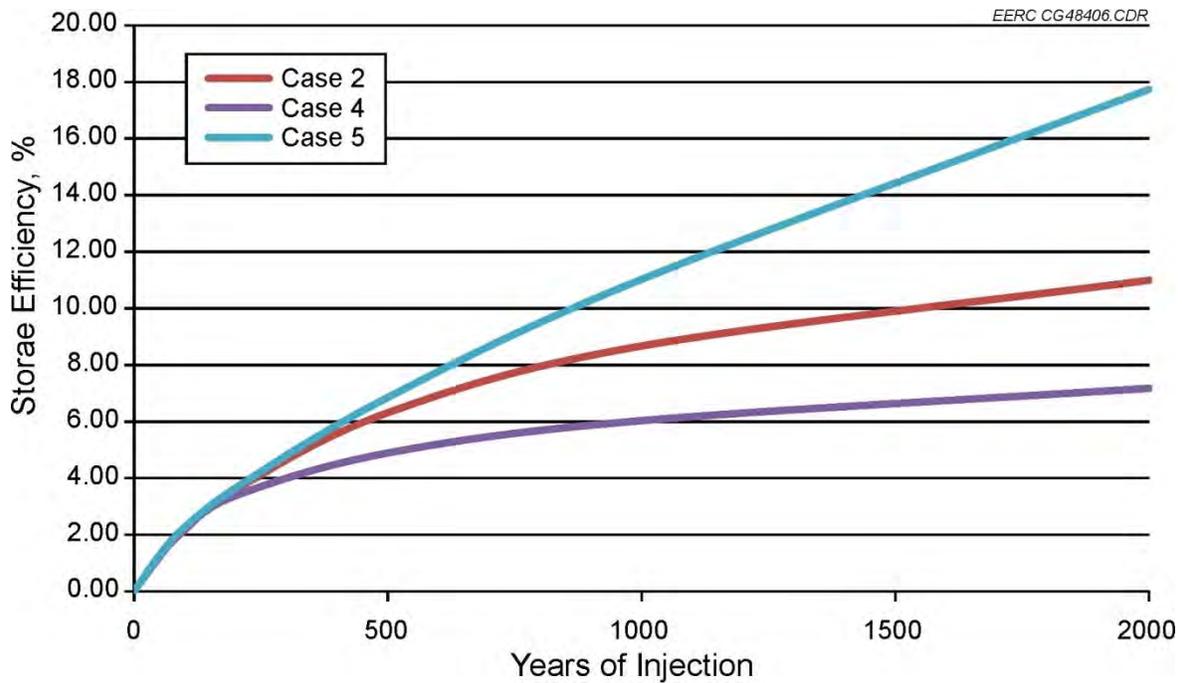


Figure 25. Dynamic effective CO<sub>2</sub> storage efficiency over time for the actual, open, and closed boundary conditions cases in the upper Minnelusa Formation.

ranging from 0.34% to 0.37%. After 2000 years, these had increased but still did not vary significantly, with a resulting range of 0.62% to 0.67% (Figure 26). This was likely due to the fact that the Qingshankou–Yaojia system models had very low permeability at the lateral edges and overlying seals in the actual boundary condition cases and adding an infinite acting aquifer to the lateral boundaries in the open-system case (Case 5) did little to increase the storage resource potential. In addition, assigning permeability 100 times lower to the overlying seals (which already had nanodarcy-range permeability) did not significantly decrease the storage resource potential in the closed-system case (Case 4). It would have been necessary to increase the permeability of the overlying formations to the microdarcy range for the system to truly act as an open system.

### Number and Type of Injection Wells

The number and type of injection wells can play an important role in maximizing the storage resource potential of a DSF. It would be extremely difficult to reach the effective storage resource potential of a target formation with a single injection well, and even if it were possible, it would take an exceedingly long period of time simply because of the injectivity limitations of a single well. Conversely, placing a million wells in a small formation is not likely to significantly increase the storage resource potential more than injecting with a few hundred wells. Additionally, the use of horizontal wells is also not likely to significantly increase the storage resource potential over vertical wells, although it may be possible to maximize it with fewer

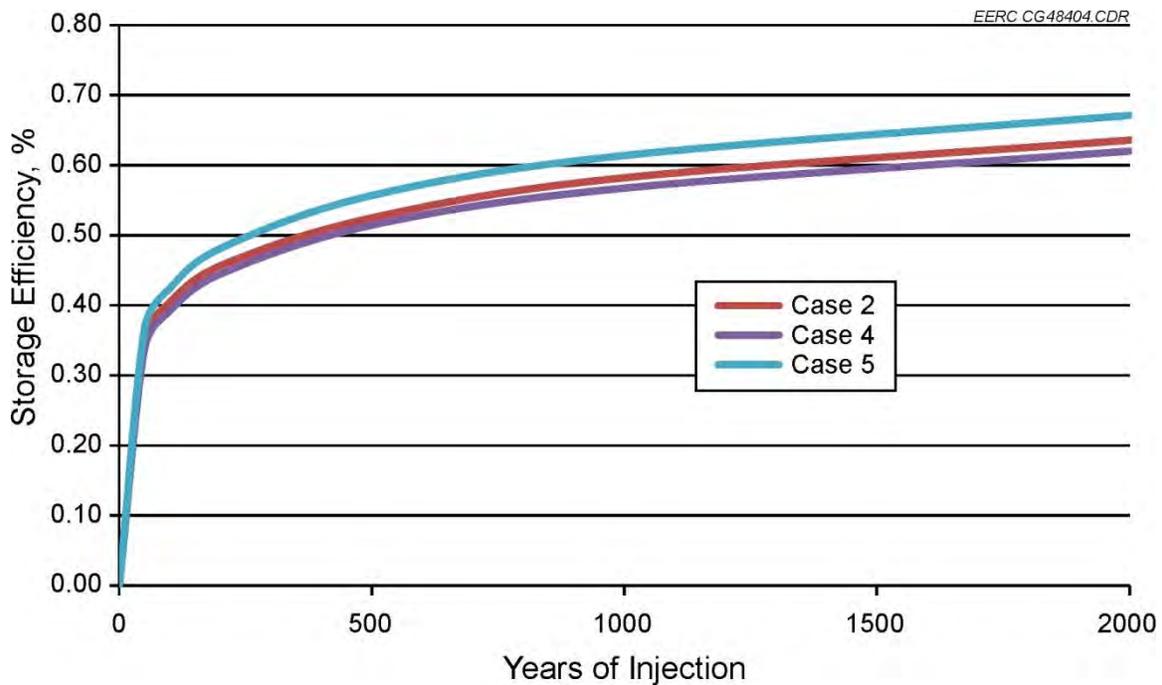


Figure 26. Dynamic effective CO<sub>2</sub> storage efficiency over time for the actual, open, and closed boundary conditions cases in the Qingshankou–Yaojia system.

overall injection wells. With this premise in mind, the base case (Case 2) for each formation in this study was designed to optimize the number and placement of injection wells in each formation. A different case utilized half of the injection wells of the base case (Case 6), and another case utilized nearly twice as many injection wells (Case 12) to look at the effect of altering the number of injection wells. One other case (Case 9) used the same number of wells as the base case; however, these wells were horizontal wells approximately 1 mile long. There was a varying degree of impact in the upper Minnelusa and Qingshankou–Yaojia systems based on the number and type of well used in these scenarios.

In the upper Minnelusa Formation model, varying the number of injectors had a fairly strong effect on the effective storage resource potential and efficiency. In Cases 2, 6, and 12, there were 474, 238 (50% less than Case 2), and 820 (72% more than Case 2) injection wells, respectively, with an efficiency of 0.55%, 1.24%, and 1.68% after 50 years and 8.1%, 11%, and 14% after 2000 years of injection for Cases 6, 2, and 12, respectively. On both time frames, the increase in wells leads to an increase in the effective storage efficiency likely because of the increase in pore space reached by the injected CO<sub>2</sub> (physical trapping), as well as the amount of formation fluid contacted by CO<sub>2</sub>. This leads to additional mixing of CO<sub>2</sub> and formation waters, thereby increasing solubility trapping. This increase may also be partially due to an increase in pressure-driven water movement out of the formation because of more local area pressure highs created by each individual injection well. However, a decrease in half of the number of injection wells only decreases the storage efficiency by 26% after 2000 years, and an increase in injection wells by 72% only increases the storage efficiency by 23% after 2000 years (Figure 27).

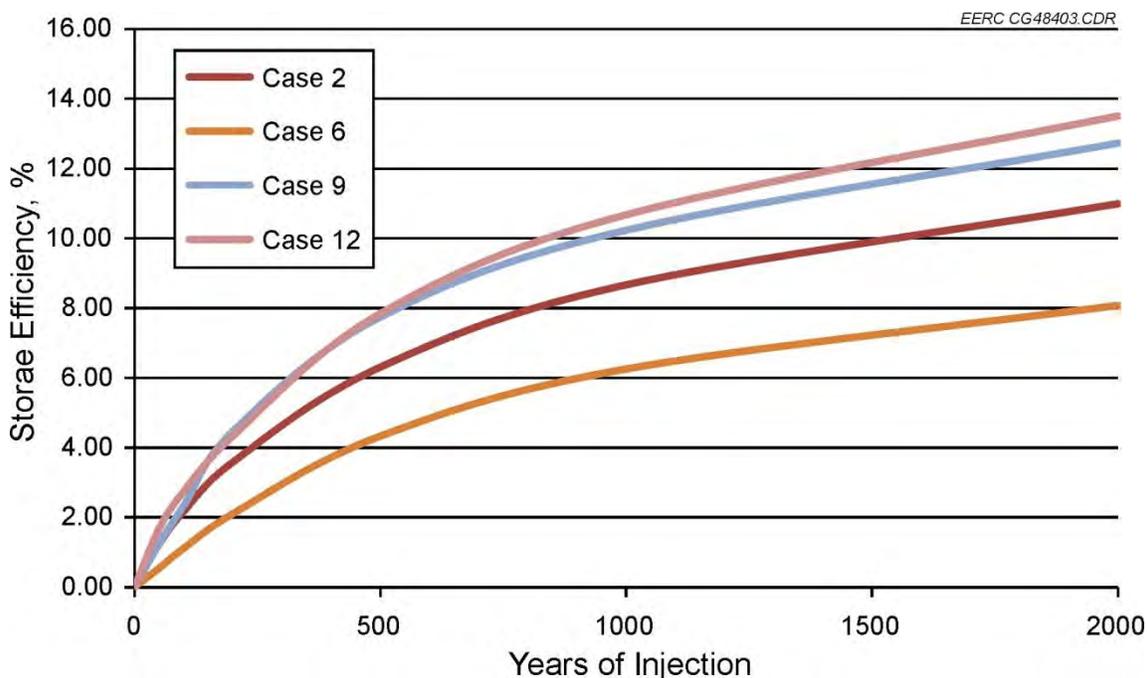


Figure 27. Dynamic effective CO<sub>2</sub> storage efficiency over time for the different numbers and types of injection wells in the upper Minnelusa Formation.

The use of horizontal injection wells in the upper Minnelusa did not make a significant difference over using an equal number of vertical wells. This is likely because the injectivity in the upper Minnelusa was very good and local pressure buildup did not limit the injectivity substantially during injection.

In the Qingshankou–Yaojia system, increasing the number of wells or using horizontal wells had very little overall effect on the effective storage efficiency (Figure 28). This is likely because the Qingshankou–Yaojia system act as a closed system and 238 vertical wells (Case 6) are able to pressure up and fill the available pressure space almost as well as using 432 (Case 2) or 827 (Case 12) vertical wells or 432 horizontal injection wells (Case 9).

While it was initially assumed that the placement of wells in both the Minnelusa and Qingshankou–Yaojia systems was ideal and the perforations were placed in cells that had transmissivity above the threshold, not all wells in each system effectively delivered CO<sub>2</sub> to their respective injection zones. In both systems, each injection well was given an injection target of 2 million tons of CO<sub>2</sub> a year for 50 years. The injection mass of each well was also limited by a maximum bottomhole injection pressure which was set at 20% greater than the initial reservoir pressure. This limit prevented every well from reaching a maximum injection target of 100 million tons of CO<sub>2</sub> in the 50-year injection period. In the Minnelusa system Case 2, 474 wells were utilized to inject a total of 1674 million tons of CO<sub>2</sub> in 50 years; however, not all the wells delivered CO<sub>2</sub> to the system equally. For example, only 96 wells (20%) injected more than 5 million tons total or an average greater than 100,000 tons of CO<sub>2</sub> a year (Table 20). It is

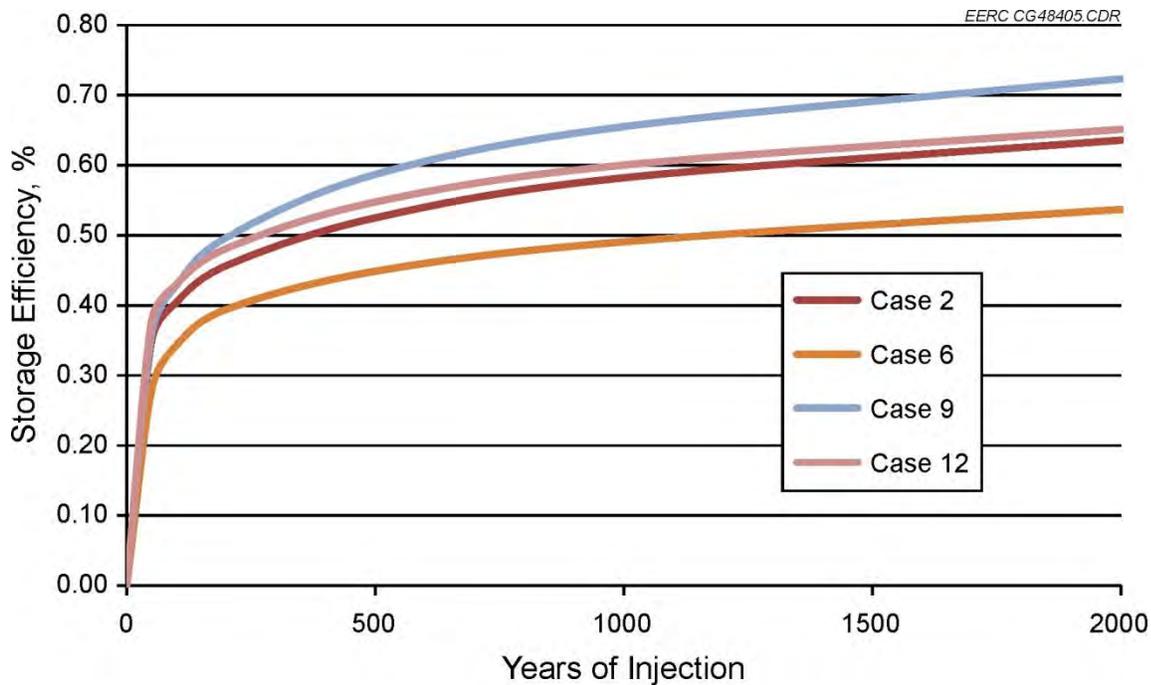


Figure 28. The number or type of injection wells does not appear to play a very strong role in increasing the dynamic effective CO<sub>2</sub> storage efficiency over time in the Qingshankou–Yaojia system.

**Table 20. Minnelusa System, Case 2 Injection Well Statistics after 50 years of Injection**

Cumulative CO <sub>2</sub> Injection per Well Greater Than, Mt	Average Annual CO <sub>2</sub> Injection per Well Greater Than, tonnes	Number of Wells	% of Wells	Cumulative Total CO <sub>2</sub> Injected, Mt	% of Total CO <sub>2</sub> Stored
40	800,000	3	1	156	9
20	400,000	10	2	325	19
10	200,000	42	9	753	45
5	100,000	96	20	1134	68
2	40,000	210	44	1498	89
1	20,000	287	61	1608	96

also worth noting that those 96 wells injected 1134 million tons of CO<sub>2</sub> or 68% of the cumulative total. The well behavior was very similar in the Qingshankou–Yaojia system where Case 2 utilized 432 wells to inject a total of 3068 million tons of CO<sub>2</sub>. Again, not all of the wells injected CO<sub>2</sub> into the system equally. As an example, only 171 wells (40%) injected more than 5 million tons total or an average annual injection total of greater than 100,000 tons of CO<sub>2</sub> (Table 21). It is also worth noting that, in both systems, most of the injection wells start off with high injection rates, and over time, the injection rate drops because of pressure buildup from

**Table 21. Qingshankou–Yaojia System, Case 2 Injection Well Statistics after 50 years of Injection**

Cumulative CO <sub>2</sub> Injection per Well Greater Than, Mt	Average Annual CO <sub>2</sub> Injection per Well Greater Than, tonnes	Number of Wells	% of Wells	Cumulative Total CO <sub>2</sub> Injected Mt	% of Total CO <sub>2</sub> Stored
40	800,000	10	2	532	17
20	400,000	38	9	1287	42
10	200,000	92	21	2053	67
5	100,000	171	40	2612	85
2	40,000	277	64	2955	96
1	20,000	329	76	3030	99

boundary conditions or well interference. Other cumulative CO<sub>2</sub> injection cutoffs are listed in Tables 20 and 21 with the accompanying statistics. This analysis of the injection well statistics also illustrates that adding more wells may not help increase the storage efficiency; however, it may allow for the maximum storage potential to be reached more quickly.

### Water Extraction Storage Optimization

The use of water extraction has been suggested as a way to increase the storage resource potential and efficiency in DSFs. The increase in the values for storage resource was found to be strongly influenced by the type of system, with closed systems resulting in the greatest benefit and open systems that are limited by local area pressure buildup benefiting from water extraction to a lesser extent (IEA Greenhouse Gas R&D Programme, 2012). These conclusions are also supported by the results from this study, as the closed Qingshankou–Yaojia system experienced a 171% increase in the storage efficiency using an equal number of wells with and without water extraction, where one case used all of the wells as injectors (Case 2) and the other case used half of the wells as injectors and the other half as water extractors (Case 7) (Table 22).

**Table 22. Qingshankou–Yaojia System Simulations Results after 50 years of Injection Operation with and Without Water Extraction**

Case	Injection Wells	Extraction Wells	Mass CO <sub>2</sub> Injected, Mt*	E, %	Change from Case 2, %
2	432	NA*	3067	0.35	0
7	216	216	8297	0.95	171
8	432	395	17,281	1.97	463
10	432**	395	17,487	1.99	470
11	432**	395**	17,625	2.01	475
12	827	NA	3312	0.38	8

\* Not applicable.

\*\* Indicates horizontal wells.

The impact of water extraction was even more profound if more injectors and water extractors were used, increasing storage efficiency by more than 450% from the base case without water extraction. It is also worth noting that the use of horizontal injectors and extractors had little impact on increasing the storage efficiency in the Qingshankou–Yaojia system, likely because the overall reservoir was pressured up and the vertical wells were able to reduce the pressure in the formations almost as well as the horizontal extractors.

The effect of water extraction on the open-system upper Minnelusa Formation was lower than in the Qingshankou–Yaojia system, although water extraction did increase the storage efficiency over the cases without water extraction when sufficient wells were utilized. In addition, the use of water extraction increased the storage efficiency by approximately 100% over the base case (Case 2) in the upper Minnelusa Formation (Table 23).

Based on the results of dynamic storage assessment of both the closed-system Qingshankou–Yaojia system and the open-system upper Minnelusa Formation, water extraction has a large potential to optimize the effective CO<sub>2</sub> storage resource of a target DSF. Although this study did not address what would be done with the formation water once it was extracted, it is likely that extracted water would have to be reinjected into another permeable formation. This could result in simply moving the problem to another area, not to mention the increased costs of handling the extracted waters. That being said, there may be options for beneficial use of the extracted waters, creating an opportunity rather than creating another challenge (IEA Greenhouse Gas R&D Programme, 2012).

### Dynamic Versus Volumetric CO<sub>2</sub> Storage Assessments

CO<sub>2</sub> storage efficiency is a dynamic process that changes over time as CO<sub>2</sub> is injected into a formation. When injection begins, the efficiency starts low, rises quickly, and then levels off to a maximum in much the same way as oil recovery changes in an oil field through time. Also similar to oil recovery is the fact that additional optimization operations can be implemented to 1) increase the rate at which storage efficiency increases or 2) increase the maximum storage efficiency. Some of these operations include the use of water extractors to decrease pressure

**Table 23. Upper Minnelusa Simulation Results after 50 years of Injection Operation with and Without Water Extraction**

Case	Injection Wells	Extraction Wells	Mass CO <sub>2</sub> Injected, Mt	E, %	Change from Case 2, %
2	475	NA*	1674	1.24	0
7	238	237	1177	0.88	-30
8	475	345	3238	2.41	93
10	475**	345	3238	2.41	93
11	475**	345**	3774	2.81	125
12	820	NA	2250	1.67	34

\* Not applicable.

\*\* Indicates horizontal wells.

buildup, increasing the maximum efficiency, and the use of different well designs or additional wells to speed up the rate at which CO<sub>2</sub> is stored. All of these concepts can be captured and estimated through a dynamic storage assessment process; however, they are very computationally and time-intensive.

With these concepts in mind, it is difficult to directly compare the dynamic and volumetric storage assessment methodologies unless the dynamic effective CO<sub>2</sub> storage efficiency is compared to the volumetric effective CO<sub>2</sub> storage efficiency when it approaches or reaches a maximum value. In this study, we ran the dynamic simulations first for 50 years, calculated the storage efficiency, and determined that neither formation had reached a maximum potential as efficiency was still increasing. The simulations were then run or extrapolated out to 2000 years of injection to determine whether or not the storage efficiency would level off and reach a plateau, at which time a maximum dynamic effective CO<sub>2</sub> storage efficiency would be reached. Based on the simulation results for the upper Minnelusa Formation, the system behaves in an open fashion, with dynamic CO<sub>2</sub> storage efficiency ranging from 0.55% to 1.7% after 50 years, 2.5% to 7.9% after 500 years, and 3.4% to 18% after 2000 years of continuous injection in cases without water extraction. The dynamic results become roughly equivalent to the volumetric efficiency values after about 500 years, indicating that the volumetric efficiency values could be used if enough time were given for CO<sub>2</sub> to be injected (Table 24). In the Qingshankou–Yaojia system, the dynamic efficiency varied from 0.28% to 0.40% after 50 years, 0.45% to 0.60% after 500 years, and 0.62% to 0.72% after 2000 years of continuous injection in cases without water extraction. These results are in close agreement with the calculated closed-system efficiency values and indicate that the system is closed or semiclosed (Table 25). This supports the use of a volumetric approach for similar systems, as long as closed-system storage efficiency values are applied.

In open-system cases, the dynamic CO<sub>2</sub> storage resource potential is time-dependent, and it asymptotically approaches the volumetric CO<sub>2</sub> storage resource potential over very long periods of time (Figure 29). This is very similar to other resource industries, namely, mining and the oil and gas industries, where CO<sub>2</sub> is a resource that can only be fully realized if it is exploited to its maximum, using advanced technology, notwithstanding time, economics, regulatory, and other considerations. In closed systems, the maximum efficiency is reached much more quickly, and the results are roughly equivalent to the volumetric results calculated using a closed-system storage efficiency term (Figure 30). These results indicate that the volumetric assessments can be used as long as an open- or closed-system efficiency term is applied appropriately, with the understanding that the effective CO<sub>2</sub> storage efficiency of a formation would likely take hundreds of wells spaced throughout a formation's area, and it would likely take decades or, possibly, thousands of years of injection to fully realize the effective CO<sub>2</sub> storage resource potential.

### **Applicability and Limitations**

The methods described in this report are valid for estimating the effective volumetric and dynamic CO<sub>2</sub> storage resource potential and efficiency for entire DSFs in sedimentary basins. The volumetric and dynamic storage efficiency values in this study were developed for entire geologic formations and were not designed for estimating the storage efficiency of a single

**Table 24. Minnelusa System Effective CO<sub>2</sub> Storage Efficiency**

	Low	High
Volumetric Efficiency – Closed System	0.54%	0.54%
Volumetric Efficiency – Open System	2.9%	11%
Dynamic Efficiency – 50 years’ Injection	0.55%	1.7%
Dynamic Efficiency – 200 years’ Injection	1.9%	4.3%
Dynamic Efficiency – 500 years’ Injection	2.5%	7.9%
Dynamic Efficiency – 2000 years’ Injection	3.4%	

**Table 25. Qingshankou–Yaojia System Effective CO<sub>2</sub> Storage Efficiency**

	Low	High
Volumetric Efficiency – Closed System	0.21%	0.21%
Volumetric Efficiency – Open System	1.3%	10%
Dynamic Efficiency – 50 years’ Injection	0.28%	0.40%
Dynamic Efficiency – 200 years’ Injection	0.39%	0.52%
Dynamic Efficiency – 500 years’ Injection	0.45%	0.60%
Dynamic Efficiency – 2000 years’ Injection	0.62%	0.72%

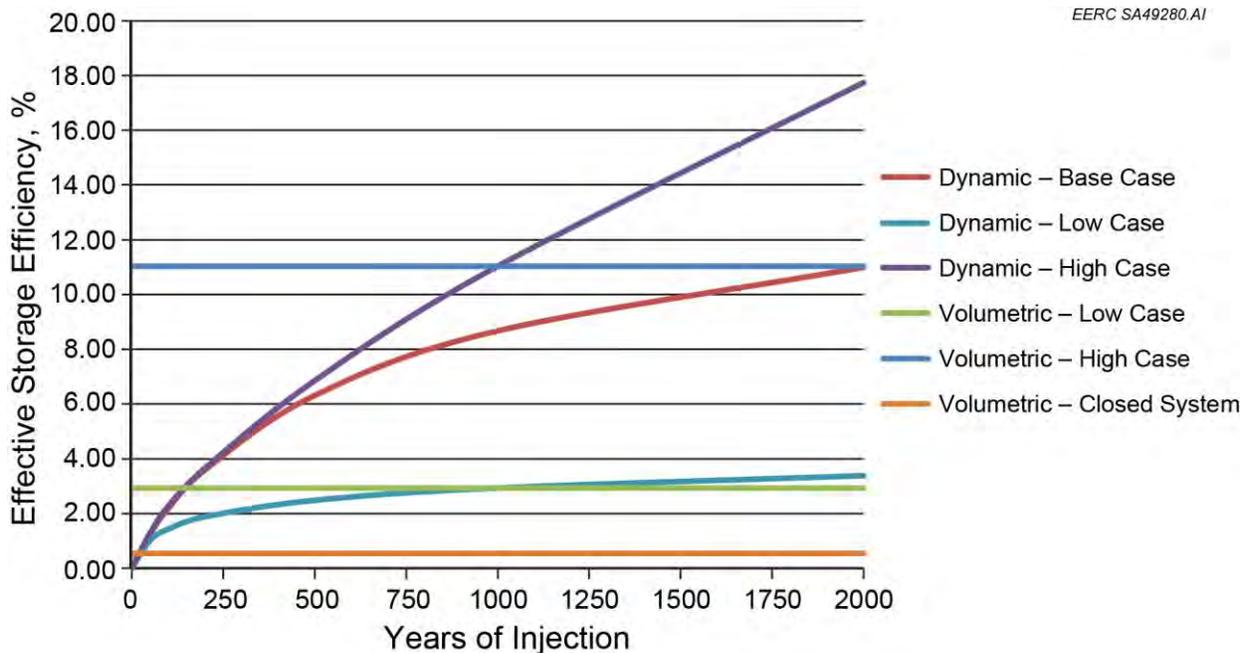


Figure 29. The dynamic CO<sub>2</sub> storage efficiency of open systems is very time-dependent and slowly reaches an asymptote over time which approaches the volumetric effective CO<sub>2</sub> storage efficiency, as shown here with the open-system Minnelusa Formation.

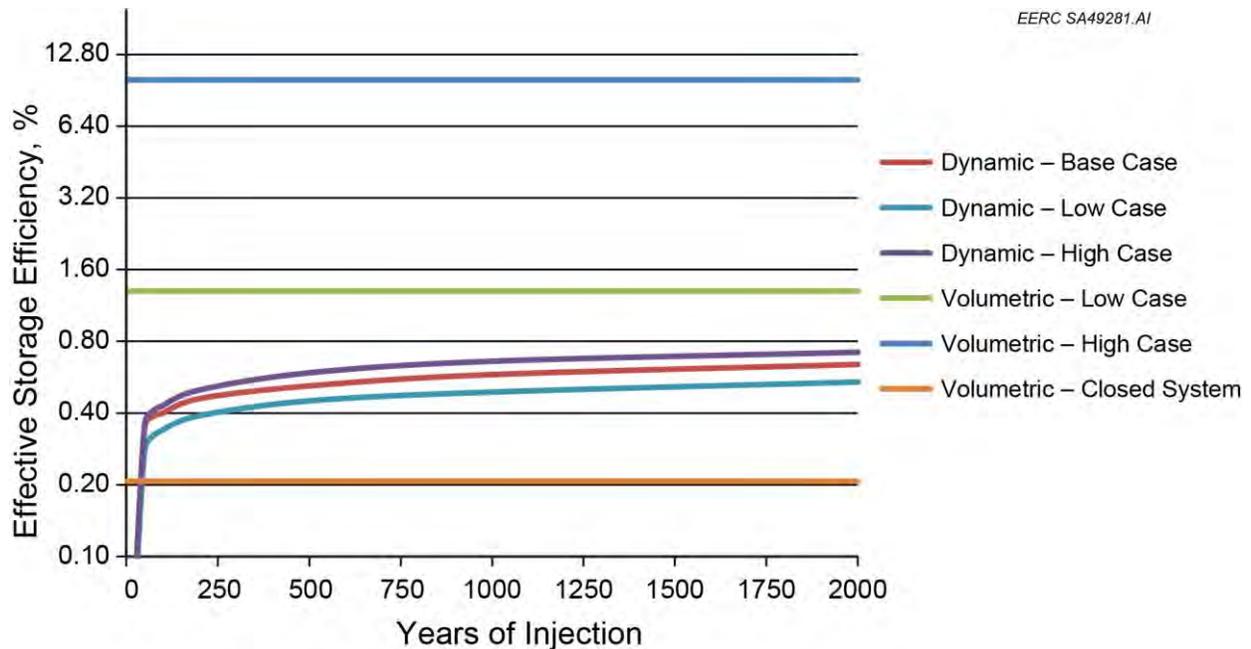


Figure 30. The maximum dynamic CO<sub>2</sub> storage efficiency is reached quickly in the Qingshankou–Yaojia system and is similar to the volumetric efficiency as calculated for a closed system.

injection well or project. Because this study focused on determining the effective CO<sub>2</sub> storage efficiency for an entire formation and not a single injection location, the displacement efficiency terms ( $E_D$ ) could not be broken down into the individual components. The value for the percentage of the amenable geology ( $E_{geol}$ ) could be quantified; however, this will be very site-specific, as geologic formations occur with different extents, depths, thicknesses, and properties. As such, at minimum, a quick assessment should be made to determine the fraction of the pore volume that is amenable to storage before the displacement efficiency terms are applied when the volumetric efficiency and resource potential of a formation are estimated.

If an assessment is made using the dynamic approach, it will be important to include the entire extent of the formation and overlying seals. This will be necessary to adequately model whether or not the system is open or closed and to what extent, as a formation is only truly open if the in situ fluids can be displaced out of the formation at a rate equal to the target injection rate.

Simulations of injection operations on entire formations are very computationally intensive and require very large grids, with millions of cells. This is further complicated by the inclusion of the overlying formations. To run these simulations in a time frame that is reasonable, very large cells need to be used to reduce the computational time, even with the most sophisticated computer hardware and software. The grid cell sizes used in this study were on the order of hundreds to thousands of meters in size horizontally and sometimes tens of meters in thickness. As a result, some of the processes that occur in a CO<sub>2</sub> storage project may not have been captured adequately. Since the goal of this project was to determine the storage efficiency of an entire DSF, the

displacement efficiency of individual injection wells, the size of individual CO<sub>2</sub> plumes, and the rate that CO<sub>2</sub> dissolved into the formation waters may not have been adequately captured.

The simulations used to determine the dynamic CO<sub>2</sub> storage efficiency in this study utilized hundreds of injection wells, placed miles apart, in optimal locations with respect to both the geology and spacing. As in oil and gas exploration, many wells would be drilled in areas that did not have optimal geology for injection that would have to be plugged and abandoned, and the planned spacing and storage efficiency optimization would take a basinwide management strategy for implementation. Similar practices are utilized on oil and gas exploration and production, such as well spacing requirements and unitized fields. Neither of these issues is insurmountable and both are worth consideration, but both were outside the scope for this project.

## **FUTURE WORK**

This study compared the volumetric and dynamic effective CO<sub>2</sub> storage resource estimation methodologies on two formations. While the results of this study are very illustrative, it may be worthwhile to investigate additional formations to determine whether these results hold true for a wider cross section of geologic conditions and depositional environments. In fact, the EERC is currently investigating the effective CO<sub>2</sub> storage resource potential of several additional formations across a wide range of depositional environments for DOE. That study is focused on improving the methodologies used to estimate the effective CO<sub>2</sub> storage resource potential and will likely build from the results of this study.

Solubility trapping may also need to be investigated more in the future, as it may play an important role in geologic storage of CO<sub>2</sub>. However, there are concerns in this study as to whether or not the physics of the solubility trapping process are adequately captured by the gridding used in this study.

## **CONCLUSIONS**

In order to compare volumetric and dynamic resource estimation methodologies, it was first important to evaluate and compare the volumetric methods in the literature. As a result of this comparison, it was determined that all of the volumetric CO<sub>2</sub> storage resource methodologies resulted in roughly equivalent values for the effective storage resource of a DSF. In addition, most of these methodologies use the same base equation where the mass of CO<sub>2</sub> that can be stored in a DSF is equal to the pore volume of the DSF multiplied by a CO<sub>2</sub> storage efficiency term. As such, it was determined that the method and storage efficiency terms used in the DOE Carbon Sequestration Atlas of the United States and Canada (U.S. Department of Energy, 2010) would be used for the basis of this comparison since the storage efficiency terms had already been thoroughly developed for both open and closed systems. In addition, an approach was also presented that goes through a method to determine the effective pore volume (the pore volume amenable to CO<sub>2</sub> storage) and a way to apply the effective CO<sub>2</sub> storage efficiency to estimate the effective CO<sub>2</sub> storage resource potential of a target DSF.

The dynamic CO<sub>2</sub> storage resource potential and efficiency was determined through the use of reservoir simulation. In both the volumetric and dynamic approaches, a geocellular model was

constructed of the entire storage formation and the overlying sealing formations all the way to the surface. In both the volumetric and dynamic CO<sub>2</sub> storage approaches, the same geologic model was used so that the assessments made could be compared on a consistent basis. For the purposes of this study, three DSFs were selected in different geographic regions, with different geologic conditions, to try to determine the validity of the volumetric estimates and the level of agreement between the volumetric and dynamic approaches.

The open-system upper Minnelusa Formation in the Powder River Basin, United States, and the closed Qingshankou–Yaojia system in the Songliao Basin, China, were used in this evaluation. These DSFs were selected to determine whether or not the open-system DOE storage efficiency or the closed-system efficiency proposed by Zhou and others (2008) was applicable for either formation. In both models, the effective open-system and closed-system storage efficiency terms were determined so they could be compared to the storage efficiency as determined through the dynamic approach. As determined through the volumetric method, the open-system effective CO<sub>2</sub> storage efficiency in the upper Minnelusa Formation was 2.9% to 11%, and the closed-system effective CO<sub>2</sub> storage efficiency was 0.54%. In the Qingshankou–Yaojia system, the open-system efficiency was 1.3% to 10%, and the closed-system efficiency was 0.21%.

As a means of testing whether or not these two storage systems are open, closed, or semiclosed, dynamic reservoir simulations were performed on each model. A total of twelve simulation cases were run for both the upper Minnelusa and Qingshankou–Yaojia models to investigate the effects of trapping mechanisms, geologic uncertainty, boundary conditions, well configuration, and injection and extraction strategies. In each simulation run, the entire formation extent within the models was used in order to better understand the pressure buildup effects. The overlying seals were also included in the models and assigned porosity, permeability, etc., from the literature. Initially injection was simulated for 50 years, and then the maximum dynamic storage was estimated running a few cases with continuous injection for hundreds or thousands of years until the maximum storage potential was reached. Based on the results of these simulations, the upper Minnelusa Formation behaved as an open system with maximum dynamic CO<sub>2</sub> storage efficiencies ranging from 0.55% to 1.67% after 50 years, 2.48% to 7.85% after 500 years, and 3.38% to 17.74% after 2000 years of continuous injection in cases without water extraction. These results are in very close agreement with the effective volumetric CO<sub>2</sub> storage efficiency (2.9% to 11%) and indicate that the use of a volumetric methodology would be applicable in formations that behave in a truly open manner as long as time is considered. In the case of the Qingshankou–Yaojia system, the dynamic approach resulted in storage efficiencies between 0.62% and 0.72%, indicating that the system is closed or semiclosed. This also indicates that the use of an open-system volumetric efficiency term is not appropriate and a closed-system efficiency term should be applied if the volumetric methodology is being utilized.

In addition to comparing the dynamic CO<sub>2</sub> storage resource estimation methodology to the volumetric approach, this study also investigated the effects of trapping mechanisms, geologic uncertainty, boundary conditions, the number and types of wells used, and water extraction techniques on the effective CO<sub>2</sub> storage efficiency. In the open-system upper Minnelusa Formation, geologic uncertainty and heterogeneity and the use of water extraction had the biggest effect on the effective CO<sub>2</sub> storage efficiency, with the number and type of wells not playing as important a role, especially in the long-injection scenarios. In the closed Qingshankou–Yaojia

system, the use of water extraction increased the storage efficiency by as much as 475% during a 50-year injection scenario. The other factors did not play much of a role in increasing the storage efficiency, as pressure buildup in the formation was by far the limiting factor on the effective CO<sub>2</sub> storage efficiency.

Trapping mechanisms are likely to play different roles in storing CO<sub>2</sub> in a formation throughout the life of the storage project. However, in this study, the main concern was with how these trapping mechanisms affect the effective CO<sub>2</sub> storage efficiency. In the simulations previously described, physical, hydrodynamic, residual gas, and solubility trapping were utilized to understand the effective CO<sub>2</sub> storage efficiency of a target formation. Over time, the trapping mechanisms lock CO<sub>2</sub> in the reservoir and gradually decrease the amount of remaining storage potential. This principle holds true for all of the mechanisms except solubility trapping. As injected CO<sub>2</sub> mixes with the native formation waters, a portion of the CO<sub>2</sub> dissolves, taking up less space in the reservoir and increasing the storage efficiency by decreasing formation pressure and allowing more CO<sub>2</sub> to be stored in the same pore volume. This study indicated that, in both formations evaluated, anywhere from 15% to 33% of the injected CO<sub>2</sub> could end up in solution in the first 50 years of injection, and this percentage could further increase to 16% to 41% after 2000 years.

Geologic uncertainty and geologic heterogeneity played an important role in the upper Minnelusa Formation but not in the Qingshankou–Yaojia system. In the upper Minnelusa, geologic uncertainty resulted in efficiencies from 3.4% to 17% in the P10 and P90 realizations, respectively, illustrating that heterogeneity and different model realizations can greatly influence the way that the injected CO<sub>2</sub> displaces the formation water. It is believed that, because the Qingshankou–Yaojia system acted as a closed system, pressure buildup was the limiting factor, resulting in little to no difference between geologic cases.

This study also investigated the effects of optimization techniques, such as the number and types of wells used, and water extraction techniques on the effective CO<sub>2</sub> storage efficiency. In the open-system upper Minnelusa Formation, the use of water extraction had the biggest effect on the effective CO<sub>2</sub> storage efficiency, with the number and type of wells not playing as important a role, especially in the long injection scenarios. In the closed Qingshankou–Yaojia system, the use of water extraction increased the storage efficiency by as much as 475% during a 50-year injection scenario. The other factors did not play much of a role in increasing the storage efficiency, as pressure buildup in the formation was by far the limiting factor on the effective CO<sub>2</sub> storage efficiency.

In conclusion, the dynamic CO<sub>2</sub> storage resource potential is time-dependent, and it asymptotically approaches the volumetric CO<sub>2</sub> storage resource potential over very long periods of time, especially in open systems. This is very similar to other resource industries, namely, mining and the oil and gas industries, where CO<sub>2</sub> is a resource that can only be fully realized if it is exploited to its maximum, using advanced technology, notwithstanding time, economics, regulations, and other considerations. In closed systems, the maximum efficiency is reached much more quickly, and the results are roughly equivalent to the volumetric results calculated using a closed-system storage efficiency term. These results indicate that the volumetric assessments can be used as long as an open- or closed-system efficiency term is applied appropriately, with the

understanding that the effective CO<sub>2</sub> storage efficiency of a formation will likely take hundreds of wells spaced throughout a formation's area, and it would likely take decades or possibly thousands of years of injection to fully realize the effective CO<sub>2</sub> storage resource potential.

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## **APPENDIX A**

# **CASE STUDIES: GEOCELLULAR MODEL CONSTRUCTION**

## CASE STUDIES: GEOCELLULAR MODEL CONSTRUCTION

### UPPER MINNELUSA FORMATION GEOCELLULAR MODEL CONSTRUCTION

The upper Minnelusa Formation in the Powder River Basin, United States, representing a deep saline formation (DSF) consisting of a single flow unit with open boundaries, was selected as a case study. The intermontane Powder River Basin is bounded by the Big Horn Mountain Range and Casper Arch to the west, Laramie Mountains and Hartville Uplift to the south, Black Hills Uplift to the east, and Miles City Arch to the north. In addition to the basin being bounded in several areas by these mountain ranges, large areas are also open to meteoric recharge and subsurface discharge, particularly in the eastern portion of the formation near the Black Hills Uplift. These recharge and discharge areas indicate that the formation is an open system. Formation thickness and the percentage of carbonates increase to the south where gradual subsidence of the Lusk Embayment occurred (Fryberger, 1984). The model's structural framework consists of two main zones: one representing the cap rock and overburden and one for the upper Minnelusa Formation (Figure A-1). The structure top of the upper Minnelusa was built using maps from Foster (1958), publicly available and picked log tops, and geostatistical interpolation (Figure A-2). The middle Minnelusa member is the base of the model created from the isopach map of Foster (1958) and controlled by additional formation top picks of the middle Minnelusa from the geophysical log data (Figure A-3).

The upper Minnelusa has a cyclic facies pattern of subtidal, sabkha, supratidal, and dune deposits. This pattern results in clean sandstones and low-porosity dolomites that are fairly continuous across the region. A petrophysical analysis was performed on the geophysical logs that were calibrated to core data to create a facies and porosity log for the selected 31 wells across the Powder River Basin. The resulting facies log displays the cyclic regressive and transgressive cycles of the upper Minnelusa and breaks the model into two distinct facies: aeolian sandstones and carbonates (Figure A-4). Resulting porosity logs were quality-checked with core analysis measurements to ensure agreement. Each facies has its own set of porosity data (Table A-1) that were crossplotted versus permeability to develop a bivariate relationship (Figure A-5). A formation trend of 35° north was set in the data analysis, along with vertical and horizontal variograms.

The sequential indicator simulation (SIS) stochastic modeling algorithm was used to distribute the facies into the structural framework, creating a geocellular facies property. Resulting facies proportions were 42% carbonates and 58% sand for the base case model. The porosity property was conditioned to the facies property and distributed using the statistical values in Table A-1. The permeability property was distributed according to the bivariate relationship established during petrophysical analysis (Figure A-6). Pressure, temperature, and total dissolved solids (TDS) vary significantly across the basin because of extremely shallow and deep formation depths and, as a result, were carefully added to the model to ensure an accurate representation of these properties. A hydrostatic pressure gradient of 9.8 MPa/km was used since reported gradients from drill stem tests ranged from 8.5 to 10.6 MPa/km (Wyoming Oil and Gas

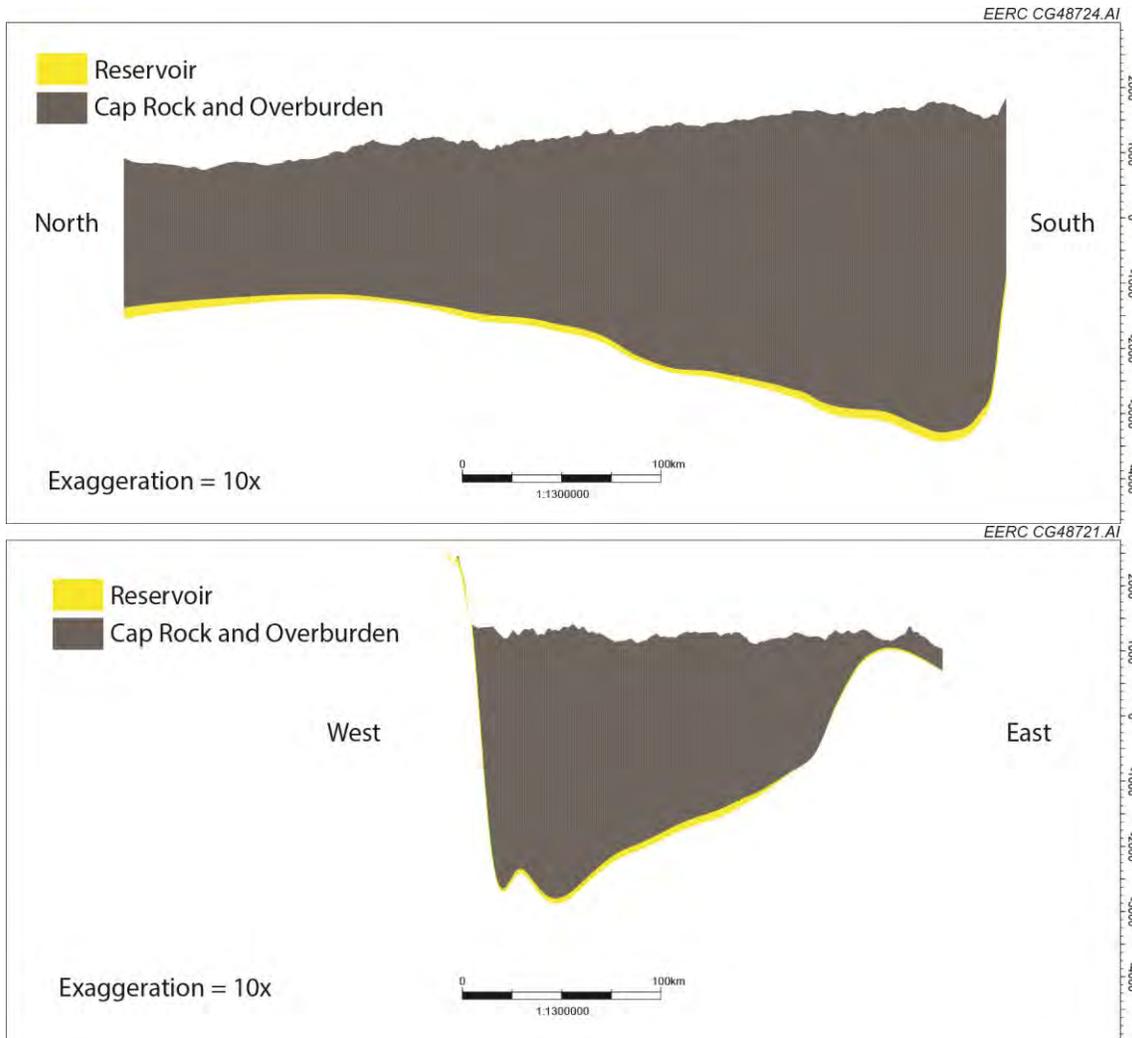


Figure A-1. North-south and east-west cross sections of the upper Minnelusa Formation in the Powder River Basin, United States, showing the two main zones in the model (vertical exaggeration = 10 $\times$ ).

Conservation Commission, 2013). A temperature gradient of 0.022 $^{\circ}$ C/m was derived and distributed by measured depth in the model starting from a mean surface temperature of 16 $^{\circ}$ C (2013). The salinity property was also determined from the Enhanced Oil Recovery Institute (EORI) database (2013), and an exponential function was fit to create a relationship between TDS and depth.

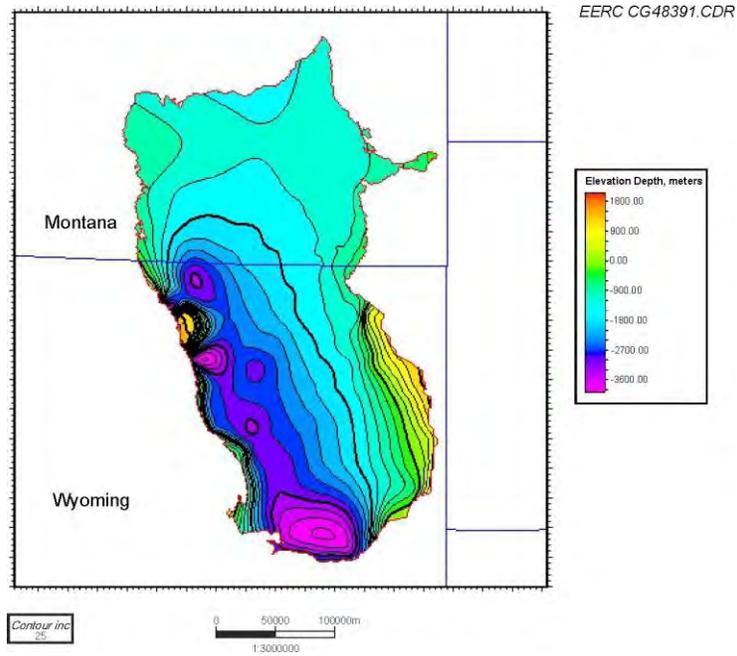


Figure A-2. Interpreted structure top of the upper Minnelusa Formation from Foster (1958), geophysical well logs, and interpolation.

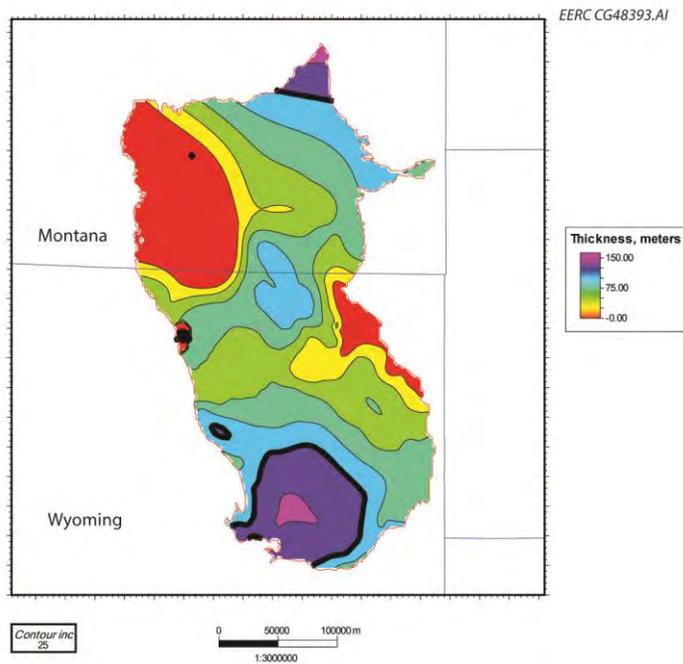


Figure A-3. Interpreted isopach map of the upper Minnelusa Formation from Foster (1958), geophysical well logs, and interpolation.

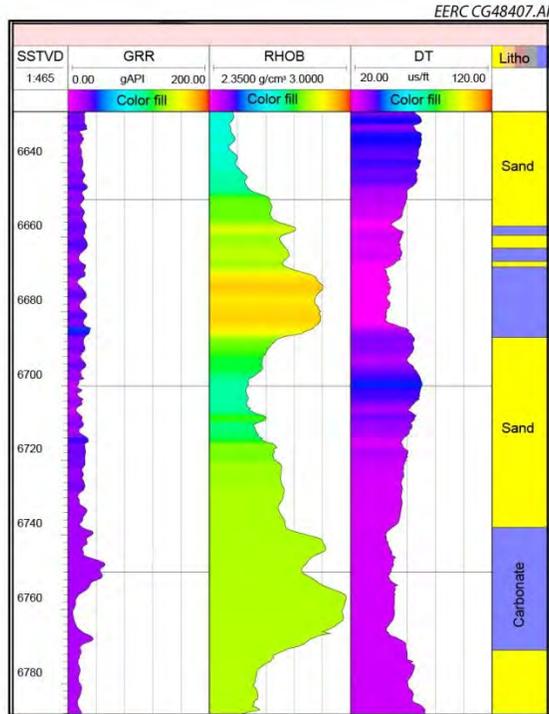


Figure A-4. Facies log for the upper Minnelusa model.

**Table A-1. Calculated Statistical Porosity and Permeability Values for Each Facies in the Upper Minnelusa Formation**

Porosity	Minimum	Mean	Maximum	Standard Deviation
Sandstone	0	0.063	0.246	0.048
Dolomite	0	0.01	0.055	0.011
Permeability	Minimum	Mean	Maximum	Standard Deviation
Sandstone	0.01	0.065	33	3.9
Dolomite	0.01	192.5	385	48.1

Key wells were selected to cover a majority of the upper Minnelusa Formation in the basin, helping to eliminate uncertainty in many areas; however, the entire basin could not be covered because of the lack of site-specific well data. Because of the lack of data points, increased uncertainty existed outside a given radius from the well, i.e., the distance of the variogram used to create the facies model. To determine the amount of uncertainty, an analysis was performed on the facies distribution and, essentially, the variogram used to distribute the facies. The variogram radius was changed to determine confidence in the distribution of the facies away from the wellbore. Outside of the variogram range, the facies distribution was

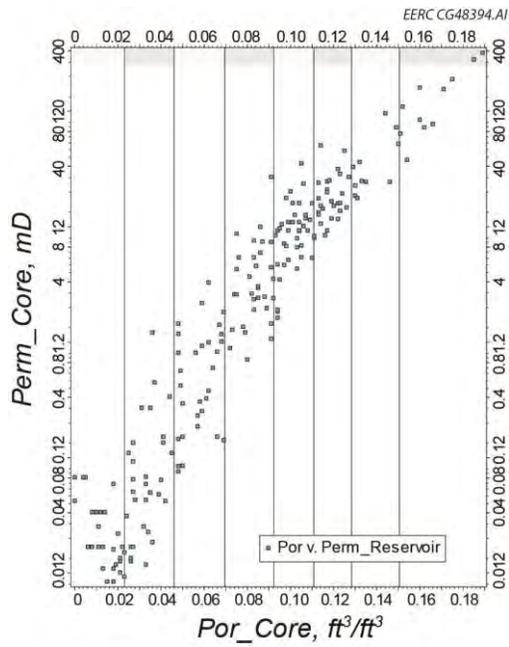


Figure A-5. Porosity–permeability crossplot of the sand facies in the upper Minnelusa Formation.

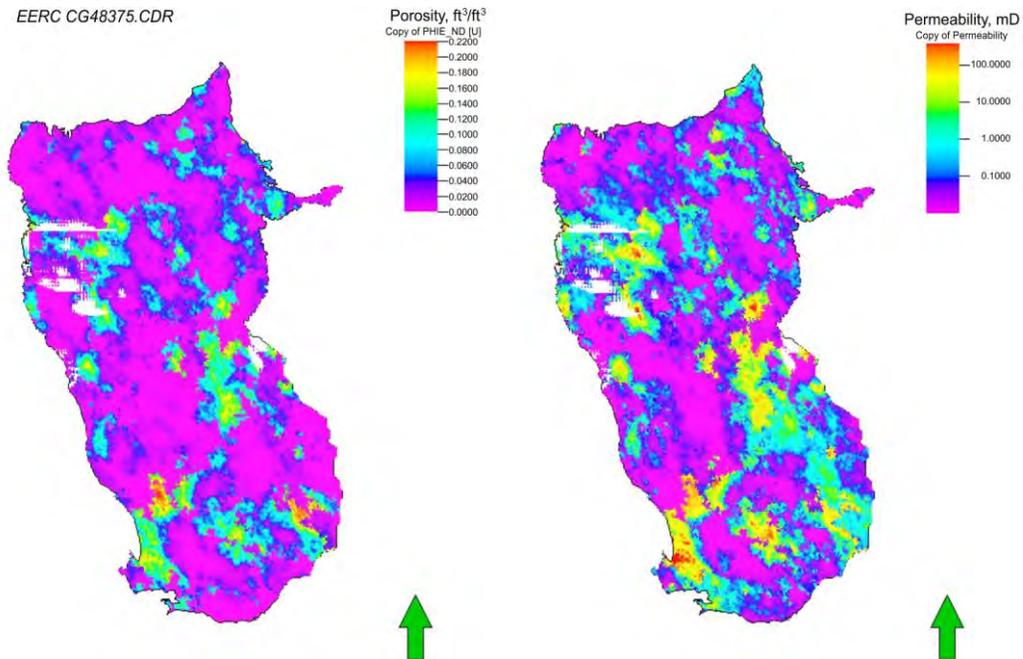


Figure A-6. Porosity and permeability were distributed throughout the upper Minnelusa Formation in the geocellular model. The white color indicates areas where the formation thickness is negligible.

changed to have either a higher or lower sand percentage. After 101 realizations, a P10, P50, and P90 model realization was selected to represent high, mid, and low formation pore volume cases (Figure A-7). The total pore volume for the P10, P50, and P90 upper Minnelusa model includes both of the facies and the full extent of the formation in the Powder River Basin (Table A-2).

Following the completion of the initial model development, the model was upscaled from a cell size of  $500 \times 500$  meters to  $1250 \times 1250$  meters. Upscaling was a necessary step before the dynamic simulations could be performed because of time constraints, as well as limitations in computing power and the simulation software. The goal of the upscaling was to reduce the overall number of cells in the model (to allow the dynamic simulations to be performed), while still honoring the geologic heterogeneity in the formation. This allowed several simulations to be performed in a time-efficient manner, while still retaining confidence that the simulation results represent a real-world scenario.

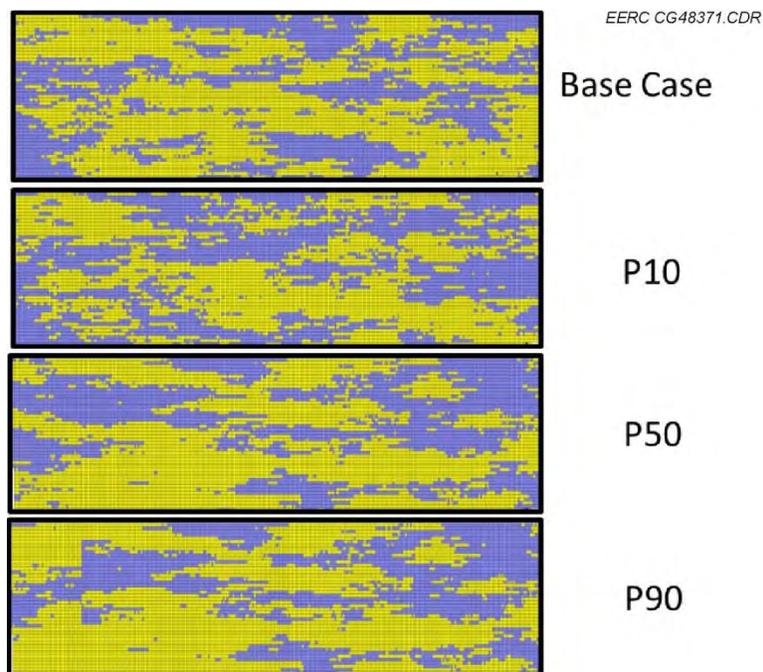


Figure A-7. Cross sections through the facies property for the base case, high, mid, and low case models. The yellow indicates a sand facies and the gray-blue indicates carbonate facies.

**Table A-2. Input Parameters Used for Upper Minnelusa Modeling and the Total Calculated Pore Volume for the P10, P50, and P90 Upper Minnelusa Formation Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Area	$A_t$	$m^2$	7.03E+10	7.03E+10	7.03E+10
Average Formation Thickness	$h_g$	m	73	73	73
Average Formation Porosity	$\phi_{tot}$		0.03	0.03	0.04
Total Formation Pore Volume	$V_{PV}$	$m^3$	1.53E+11	1.74E+11	2.12E+11

## **QINGSHANKOU–YAOJIA SYSTEM GEOCELLULAR MODEL CONSTRUCTION**

The Qingshankou and Yaojia Formations in the Songliao Basin, China, representing two interconnected DSFs acting as a single flow unit with closed boundaries, was selected as the other case study. The intermontane Songliao Basin is bounded by the Greater Khingan, Lesser Khingan, and Changbai Mountains. The target formations are completely surrounded by mountains, which were uplifted after deposition of the Qingshankou and Yaojia Formations, creating a closed system that is compartmentalized by sealing faults. The model's structural framework consisted of two main zones: one representing the cap rock and overburden and one for the Qingshankou–Yaojia system (Figure A-8). The structure top of the Qingshankou was built using maps from Li (1995), a digital elevation model (DEM), and an isopach map (Xin and Wang, 2004) to determine the model base (Figure A-9). The combined total thickness for the Qingshankou–Yaojia system varies from 60 meters on the flanks to over 700 meters in the center of the basin (Figure A-10). However, the Qingshankou is typically thicker than the Yaojia, with individual maximum thicknesses of ~320 and ~200 meters, respectively. The formation zones were further divided into depositional flow zones based on deltaic sand isopachs from Li and others (1982). The structural framework of the model resulted in nine zones, including a fluvial deltaic and lacustrine zone for the Qingshankou 1, 2, and 3 and the Yaojia 1, 2, and 3 and a cap rock zone. Zones were broken into layers after a data analysis was completed on vertical core porosity data to determine the vertical variogram.

The Qingshankou–Yaojia system is composed of a cyclic facies pattern of fluvial, deltaic, and lacustrine deposits. This pattern results in high-porosity sandstones that are compartmentalized by low-porosity lacustrine shales. This pattern repeats itself throughout the Qingshankou–Yaojia succession, creating a stacked storage system. The structural framework divided each formation member into fluvial–deltaic and lacustrine zones. In turn, this allowed for each zone to have a separate facies calculation. Lacustrine zones consisting of low-porosity and permeability mudstones act as regional baffles, while the topmost lacustrine zone is a widespread cap rock. The fluvial–deltaic complexes act as a good storage reservoir with high-porosity arkosic sandstones (Asia–Pacific Economic Cooperation, 2005). The facies model in the fluvial–deltaic system was given heterogeneity utilizing a gamma ray log from Well F64 in Wu and others (2009). Calculating shale volume allowed for heterogeneity in the model and for shaley or silty nonreservoir fluvial deltaic facies such as lake advancements or associated flood plain facies. Because of limited data to conduct a petrophysical analysis, porosity and permeability data and their bivariate relationship were determined from Ryder and others (2003). These data list details on the porosity and permeability of 81 producing fields in the Songliao Basin, 63 of which are part of the Qingshankou–Yaojiapetroleum system (Figure A-11). Statistics for each formation were compiled and supplemented with additional data from Bohacs (2012). The supplemented data helped determine histogram and crossplot end points and normal scores for the data for distribution. Mean values for each reservoir are listed in Table A-3. Data analysis on horizontal variograms was determined from reported quartz content from core analysis and average log data. Vertical variograms were determined from core porosity data.

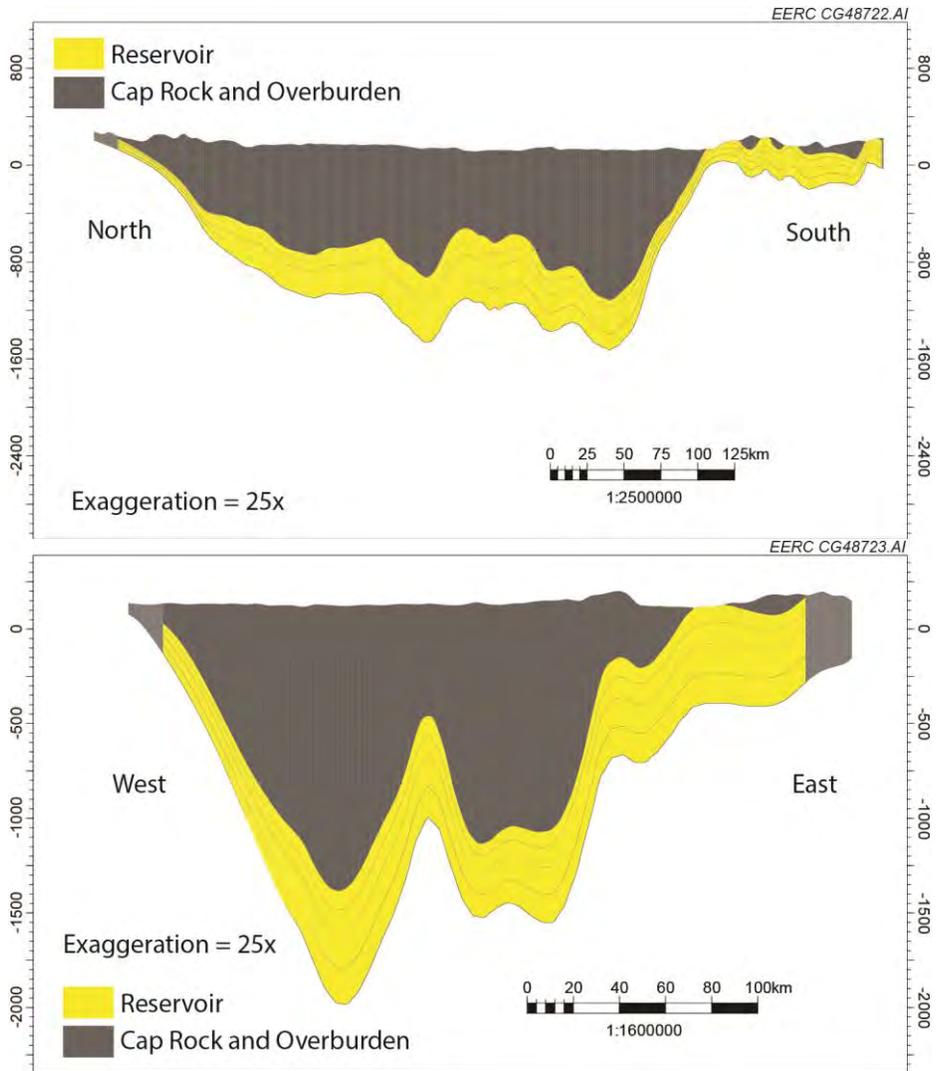


Figure A-8. North-south and east-west cross sections of the Qingshankou–Yaojia system in the Songliao Basin, China, showing the two main zones in the model (vertical exaggeration = 25×).

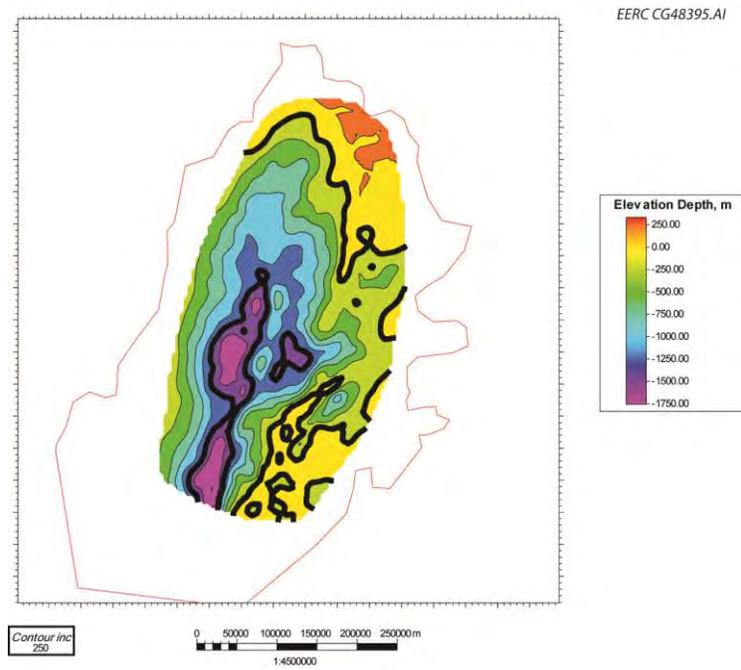


Figure A-9. Interpreted structure top of the Qingshankou Formation from Li (1995).

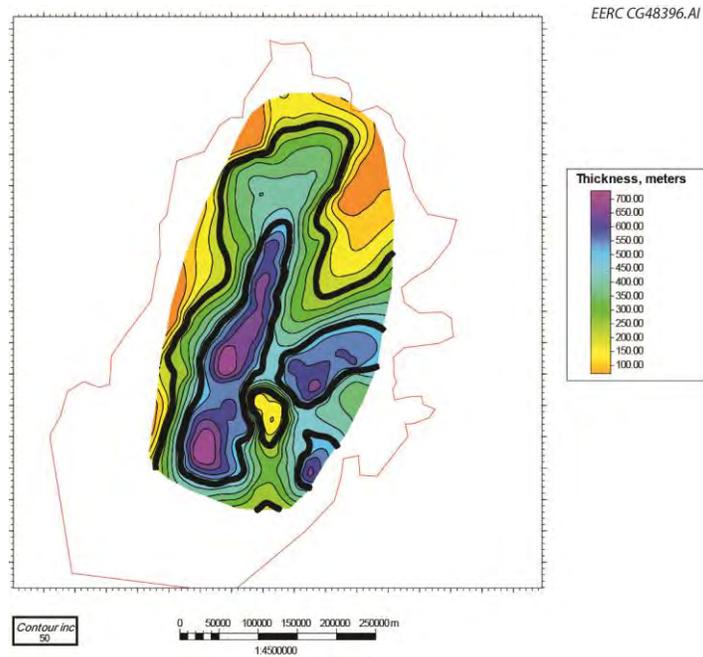


Figure A-10. Interpreted isopach map of the Qingshankou–Yaojia system using a DEM and an isopach map from Xin and Wang (2004).

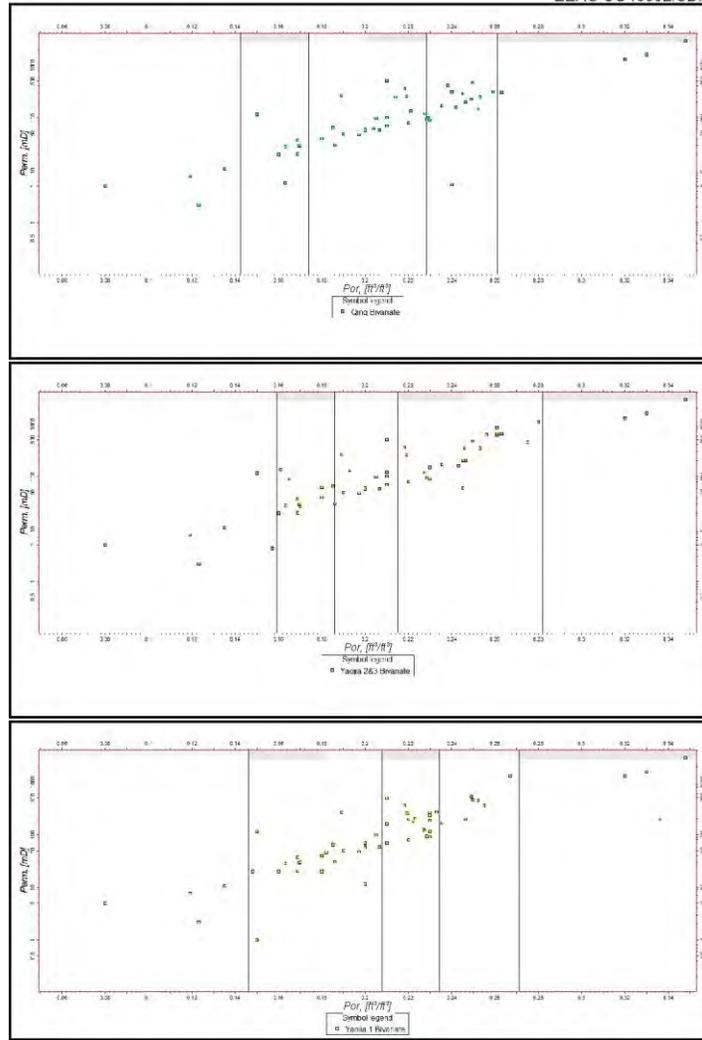


Figure A-11. Porosity–permeability crossplots for the Qingshankou–Yaojia system.

**Table A-3. Reported Statistical Porosity and Permeability Values for Fluvial–Deltaic Facies in the Qingshakou–Yaojia Formations**

Reservoir	Shaertu	Putaohua	Gaotaizi
Mean Porosity	22.5	21.8	22.9
Mean Permeability	227	111	131
Porosity (standard deviation)	5.7	5.8	5.7

The facies property was distributed into the model using SIS in order to honor the shale volume calculation and variogram ranges. The porosity and permeability properties were distributed using Gaussian random function simulation and conditioned to the facies property (Figure A-12). Porosity in the model was distributed with a different mean and standard deviation in each zone. Data end points for porosity in the fluvial–deltaic reservoir facies was supplemented from Bohacs (2012) and given a minimum and maximum of 5.0% and 34.8%. Porosity data for the nonreservoir fluvial–deltaic facies and lacustrine facies were not identified from the literature review; however, an analog lacustrine shale from the Ordos Basin of China has porosity measurements with a minimum and maximum of 0.4% and 1.5% (Zou, 2012). Permeability was distributed utilizing the bivariate relationship modified from Ryder and others (2003). Pressure, temperature, and TDS properties were distributed using a depth-dependent gradient. The Near Zero Emission Coal (NZEC) Work Packages Reports (2007) determined pressure and temperature gradients for the Qingshankou Formation from unpublished data in the Jilin oil field. Gradients are 0.0376°C/m and 11.6 MPa/km for temperature and pressure, respectively. Although a TDS gradient is not defined, one was determined using a maximum TDS measurement in the reservoir (43.7g/L) and the maximum measured depth in the model (2220 m) (Near Zero Emission Coal, 2007).

An uncertainty analysis was performed on the base case model to determine high, mid, and low pore volume cases. The facies parameter was selected for uncertainty analysis. To determine the amount of uncertainty in the model, the shale volume calculation in the fluvial–deltaic zone was recalculated by shifting the sand/shale cutoff within one standard deviation of the log. The calculated pore volume was then ranked, in which high, mid, and low cases were selected for simulation (Figure A-13). The input parameters and total pore volumes (high, mid, and low) are shown in Table A-4.

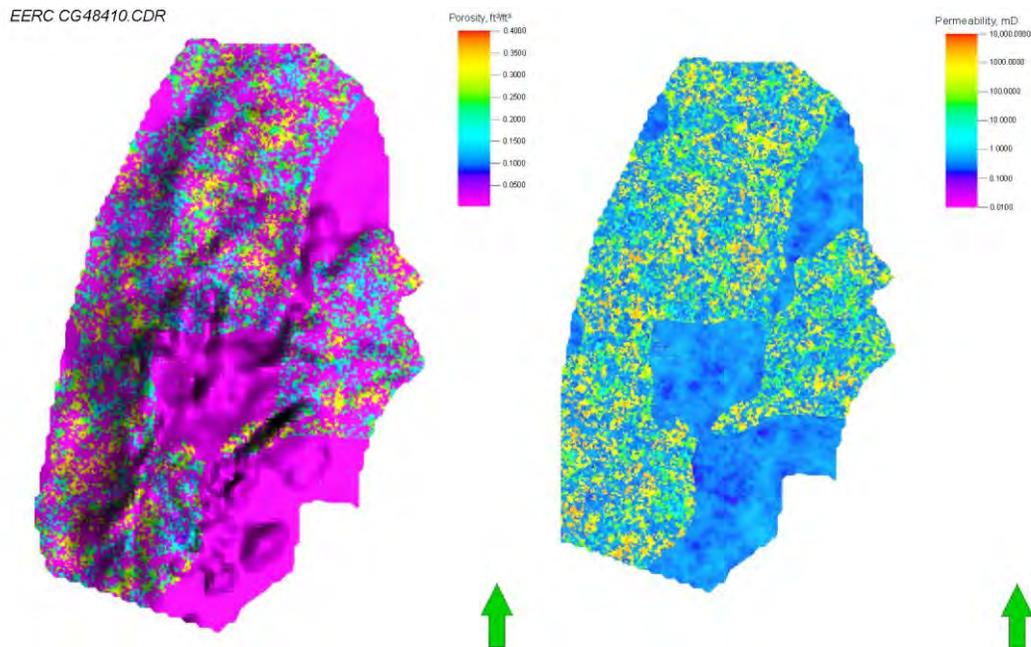


Figure A-12. Porosity and permeability distributed throughout the Qingshankou–Yaojia system model.

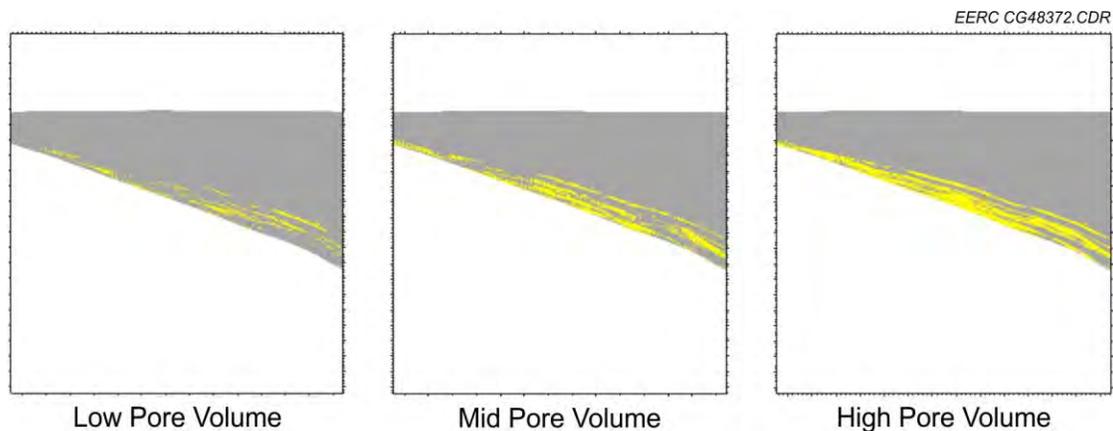


Figure A-13. High, mid, and low pore volume case cross sections through the facies property.

**Table A-4. Input Parameters Used for Qingshankou–Yaojia System Modeling and the Total Calculated Pore Volume for the P10, P50, and P90 Qingshankou–Yaojia System Models**

Parameter	Symbol	Unit	P10	P50	P90
Total Area	$A_t$	m <sup>2</sup>	1.23E+11	1.23E+11	1.23E+11
Average Formation Thickness	$h_g$	m	370	370	370
Average Formation Porosity	$\phi_{tot}$		0.03	0.06	0.09
Total Formation Pore Volume	$V_{PV}$	m <sup>3</sup>	7.42E+11	1.29E+12	1.81E+12

Like the Minnelusa model, the Qingshankou–Yaojia system model was upscaled from a cell size of 500 × 500 meters to 1250 × 1250 meters. This was to reduce the overall number of cells in the model (to allow the dynamic simulations to be performed), while still honoring the geologic heterogeneity in the formation. Upscaling the model allowed several simulations to be performed in a time-efficient manner, while still retaining confidence that the simulation results represent a real-world scenario.

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## **APPENDIX B**

# **DYNAMIC SIMULATION SUMMARY AND RESULTS DEMONSTRATION**

## DYNAMIC SIMULATION SUMMARY AND RESULTS DEMONSTRATION

### MODEL SETTINGS

All of the dynamic simulations were performed by the Energy & Environmental Research Center (EERC) using Computer Modelling Group's (CMG) software package ([www.cmgl.ca/](http://www.cmgl.ca/)) on a 188-core high-performance parallel computing cluster. The grid size for both the upper Minnelusa Formation and the Qingshankou–Yaojia system were upscaled to  $1250 \times 1250$  meters, which resulted in models containing 4.12 and 5.54 million cells, respectively. The simulation system includes brine and CO<sub>2</sub> components in the fluids. The CO<sub>2</sub> is allowed to dissolve into the brine as in an actual saline system during CO<sub>2</sub> injection. The aqueous density and viscosity of the fluids were respectively correlated by using the methods from Rowe and Chou (1970) and Kestin and others (1981) with varying temperatures and pressures of the saline system over the location and depth. Henry's Law constant was correlated by Harvey's method to determine the solubility of CO<sub>2</sub> in the brine (Harvey, 1996). The rock–fluid settings were based on the lithologies found in the static geologic model. Pitts and Surkalo (1995) and Barati (2011 and 2012) reported relative permeability curves and capillary pressure based on the sedimentary lithologies, including the sandstone and dolomite, in the upper Minnelusa Formation. The relative permeability curves and capillary pressure for the Qingshankou–Yaojia system were used from published work (Zhao and Zhang, 2012; Zeng and others, 2010). The relative permeability and capillary pressure curves used for each system are shown in Figures B-1–B-6. The ratio of vertical permeability to horizontal permeability used was 0.1 for both case studies (Zhao and Zhang, 2012). Simulation parameters are listed in Tables B-1 and B-2 for the Minnelusa and Qingshankou–Yaojia systems, respectively. The compressibilities of pore used for the upper Minnelusa Formation and Qingshankou–Yaojia system are  $5.58E-7$  and  $3.85E-6 \text{ kPa}^{-1}$ , while the compressibilities of water are  $4.13E-7$  and  $2.85E-6 \text{ kPa}^{-1}$ , respectively (Zhang and others, 2005, 2008; Esken and others, 2012; Brady and Lee, 1998; Pitts, 2005; Liu and Li, 2013). The CO<sub>2</sub> density for the storage potential calculation is based on the current average pressure and temperature which is 33,646 and 15,050 kPa for both formations.

The injection wells for all simulation cases were generated and optimized by a python script to cover all of the study area where the depths are greater than 800 meters for a dense phase of CO<sub>2</sub> (supercritical phase). If the cases included water extraction, all of the extractors were placed around the injectors using the same script by following a five-spot pattern. The total number of wells used for the simulations are summarized in Table B-3. The constraints of the injection were to first satisfy the bottomhole pressure (BHP) limitation, which was calculated based on the depth of the bottomhole multiplied by the pressure gradient, 13.6 kPa/m for both formations, then the injection rate was imposed which was determined based on the injection rate sensitivity analysis.

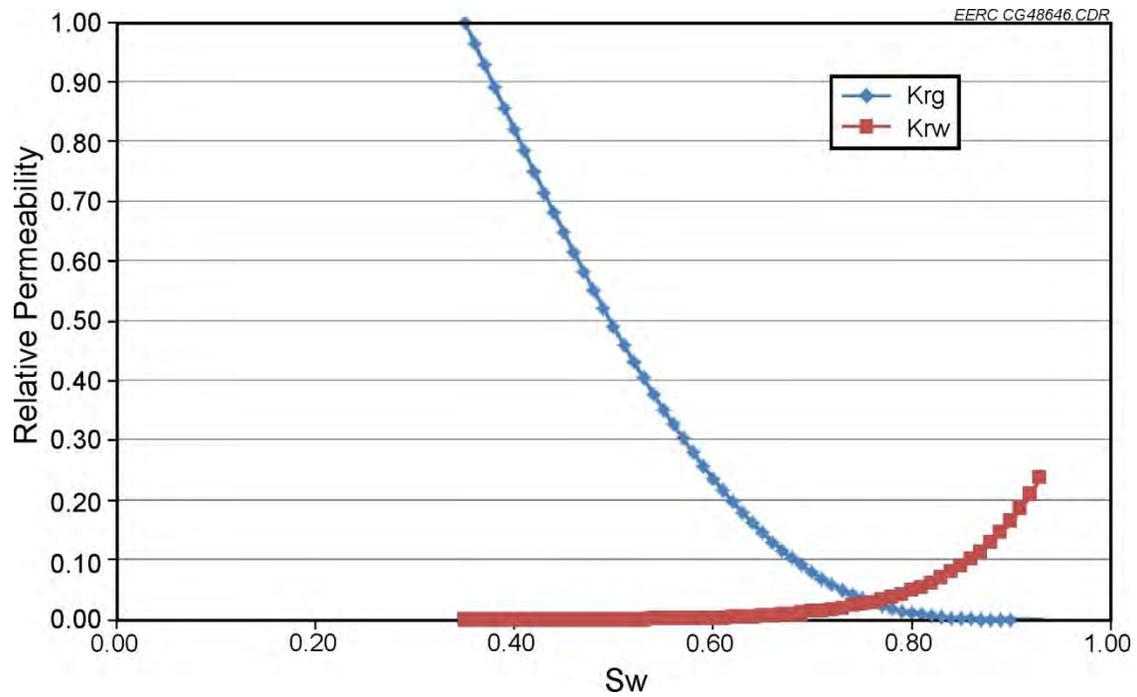


Figure B-1. Relative permeability curves for the reservoir formations of the Qingshankou-Yaojia system.

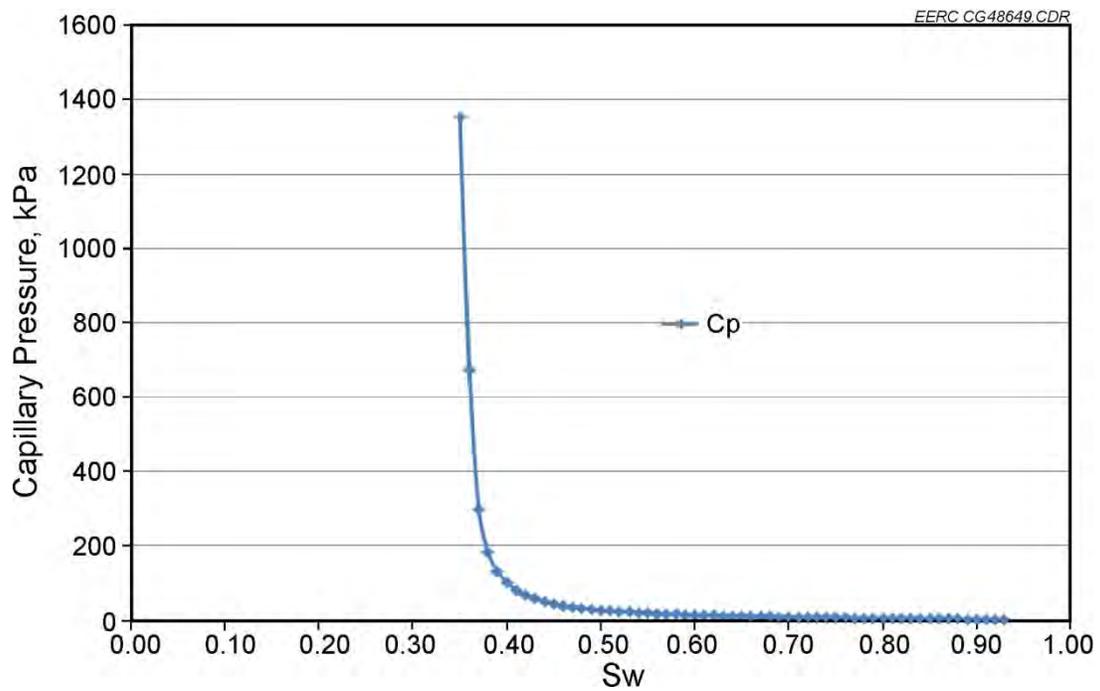


Figure B-2. Capillary pressure (kPa) for the reservoir formations of the Qingshankou-Yaojia system.

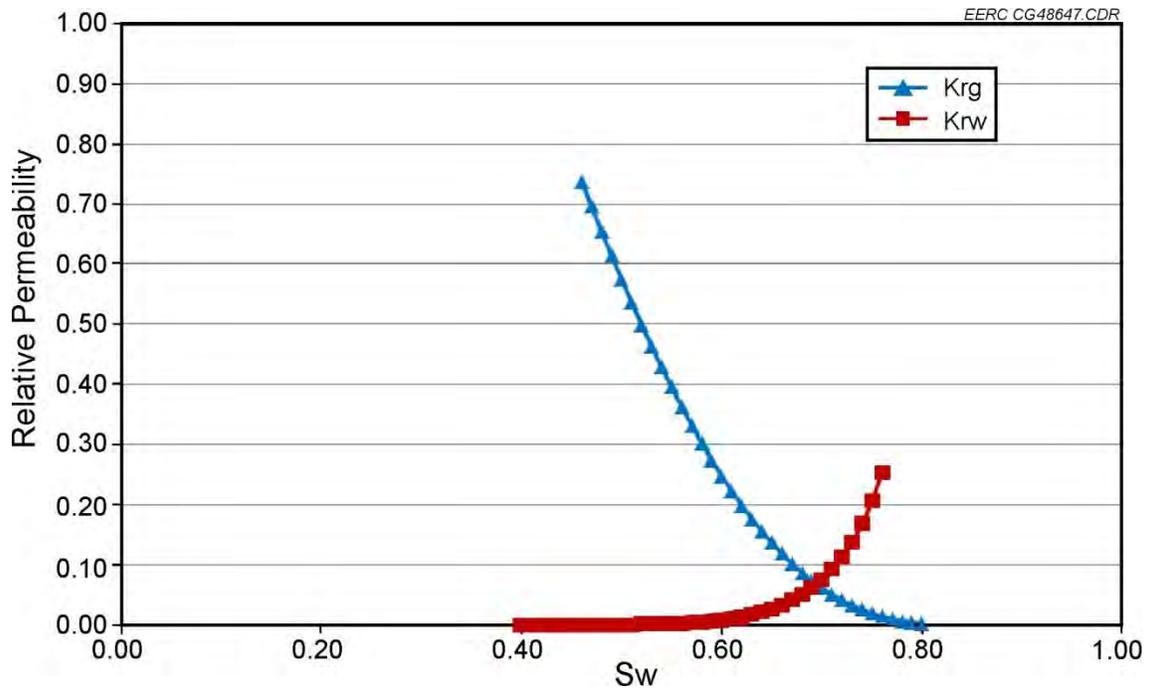


Figure B-3. Relative permeability curves for the cap rock formations of the Qingshankou–Yaojia system.

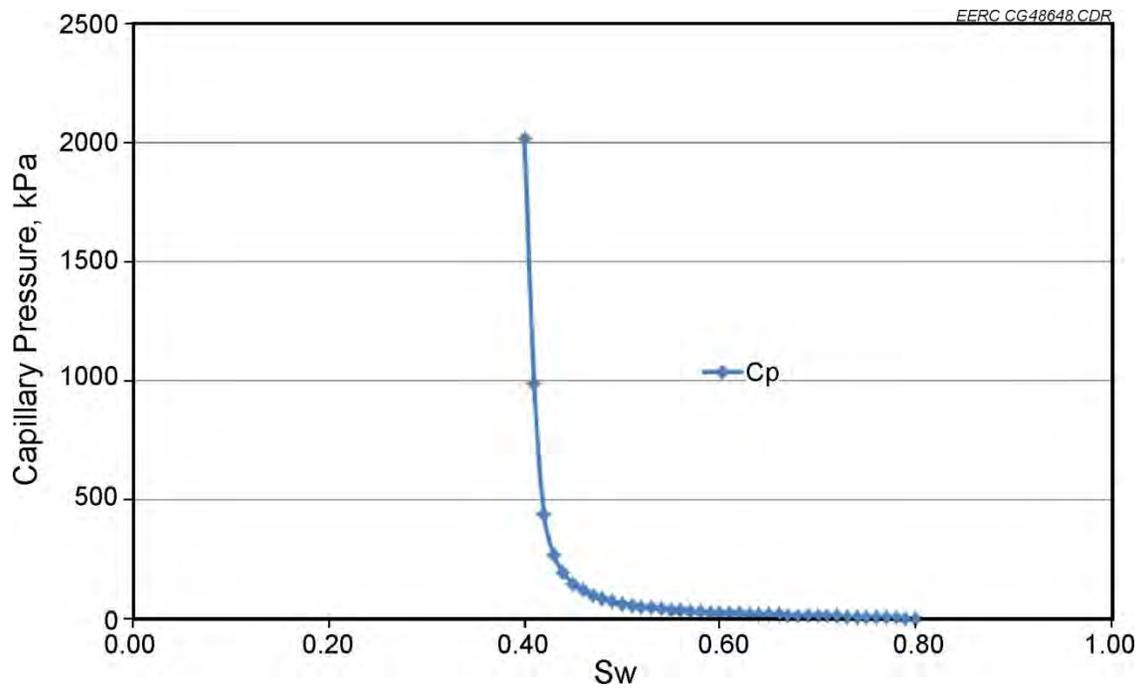


Figure B-4. Capillary pressure (kPa) for the cap rock formations of the Qingshankou–Yaojia system.

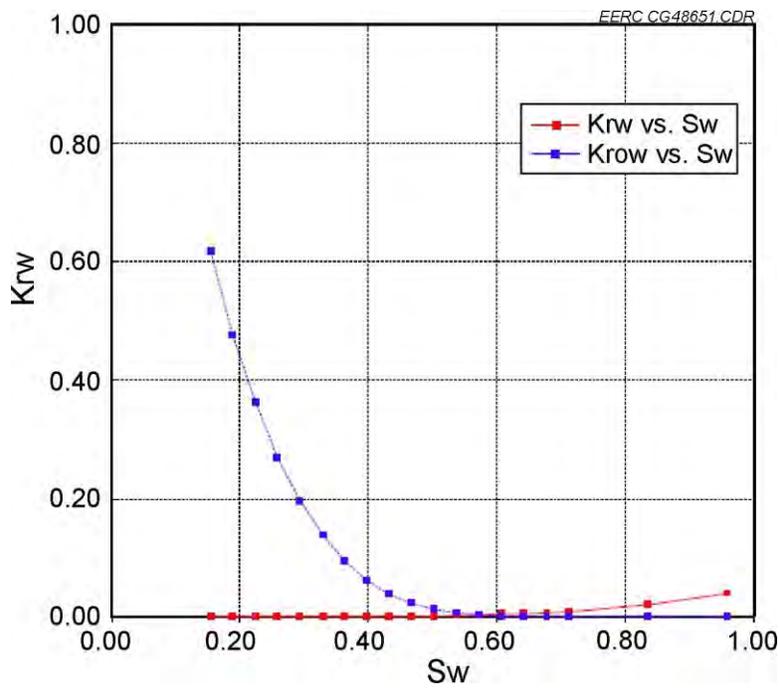
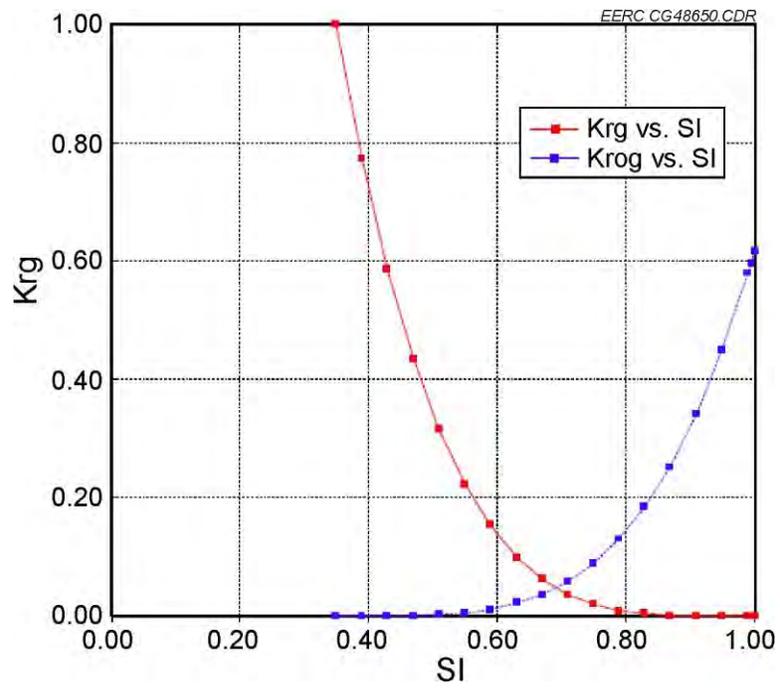


Figure B-5. Relative permeability curves of the Minnelusa system (Garcia, 2005).

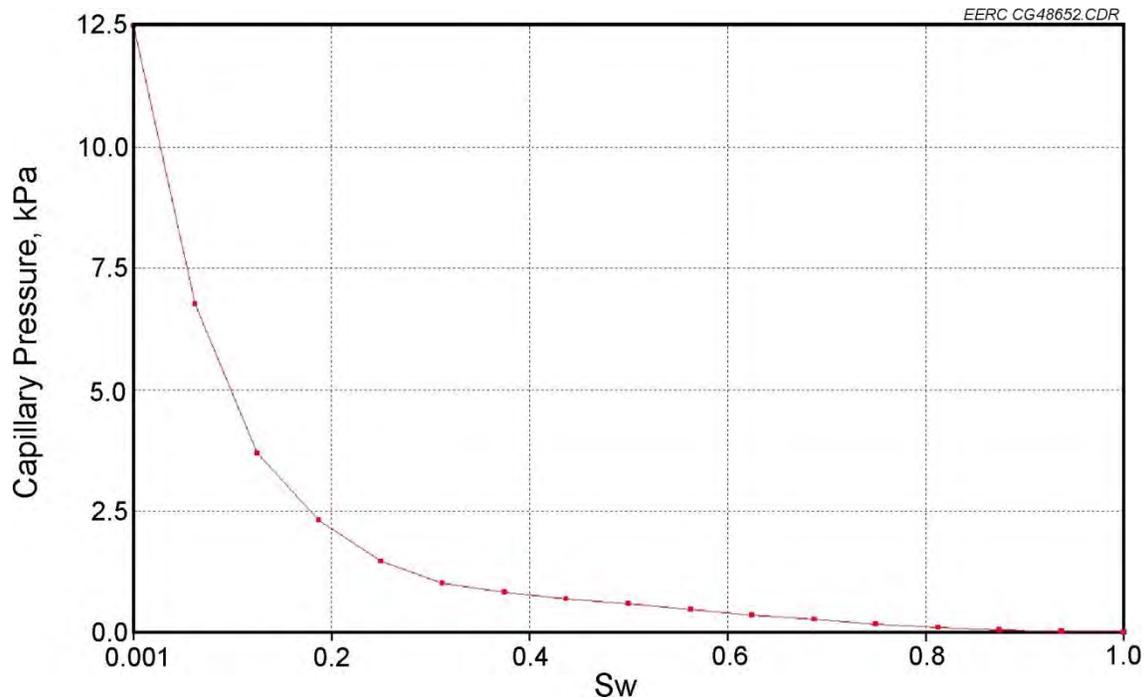


Figure B-6. Capillary pressure curve of the Minnelusa system (Barati, 2011).

The injection rate in the dynamic simulation was determined through a rate sensitivity analysis to decide what rate maximized injection for the upper Minnelusa Formation and the Qingshankou–Yaojia system. Three rates: 1 million tonnes (Mt)/year, 2 Mt/year, and 3 Mt/year for each well were tested based on the base case. The results indicate that the rate of 2 Mt/year maximized the potential storage for all simulation cases. A total of 12 simulation cases for each formation were designed to address the storage potential effect by high, mid, and low pore volume cases, boundary conditions, well configuration, and injection and extraction strategies (Table B-4).

**Table B-1. Simulation Parameters Used for Upper Minnelusa System (Barati, 2011)**

Parameters	Values
Vertical and Horizontal Permeability Ratio, $K_v/K_h$	0.1
Maximum BHP of Injection Wells, kPa	13.6 kPa/m pressure gradient used for individual wells, the range for the wells is 15077 to 64693 kPa
Relative Permeability	Based on Garcia (2005)
Capillary Pressure	Based on Barati (2011)

**Table B-2. Simulation Parameters Used for Qingshankou–Yaojia System (Zhao and others, 2012; Zeng and others, 2010; Zhang and others, 2008; Yang and Zhang, 2010)\***

Parameters		Values
Vertical and Horizontal Permeability Ratio, Kv/Kh		0.1
BHP of Injection Wells, kPa		13.6 kPa/m pressure gradient used for individual wells, the range for the wells is 12,100 to 29,897 kPa
Relative Permeability Set 1 (reservoir)	Residual water, Srw	0.35
	Residual gas, Srg	0.1
	Exponent for the curves, m	0.46
	Pore compressibility, beta (Pa <sup>-1</sup> )	4.50E-07
	Entry capillary pressure, alpha (MPa)	0.01
Relative Permeability Set 2 (cap rock)	Residual water, Srw	0.4
	Residual gas, Srg	0.15
	Exponent for the curves, m	0.46
	Pore compressibility, Beta	4.50E-07
	Entry capillary pressure, alpha (MPa)	5

\* The end points, exponents, and coefficients in Relative Permeability Sets 1 and 2 were used to generate the relative permeability curves.

**Table B-3. Wells (injection and production) Used for Each Simulation Case**

Case	Upper Minnelusa Formation		Qingshankou–Yaojia System	
	Injection Wells	Extraction Wells	Injection Wells	Extraction Wells
1	462	NA	391	NA
2	475	NA	432	NA
3	492	NA	441	NA
4	475	NA	432	NA
5	475	NA	432	NA
6	238	NA	216	NA
7	238	237	216	216
8	475	345	432	395
9	475*	NA	432*	NA
10	475*	345	432*	395
11	475*	345*	432*	395*
12	820	NA	827	NA

\* Indicates horizontal wells.

**Table B-4. Simulation Cases and Simulation Notes**

Simulation Cases	Notes
1 – P10 Actual Boundary Conditions	Testing geologic sensitivity
2 – P50 Actual Boundary Conditions	Base run for comparison
3 – P90 Actual Boundary Conditions	Testing geologic sensitivity
4 – P50 Closed Boundaries	Testing boundary conditions
5 – P50 Open Boundaries	Testing boundary conditions
6 – P50 Half the Number of Vertical Injectors	Testing well configuration
7 – P50 Half the Number of Vertical Injectors and Extractors	Testing well configuration and extraction
8 – P50 Vertical Injection and Extractors	Testing well configuration and extraction
9 – P50 Horizontal Injectors	Testing the effect of horizontal wells
10 – P50 Horizontal Injectors and Vertical Extractors	Testing well configuration and extraction
11 – P50 Horizontal Injectors and Extractors	Testing well configuration and extraction
12 – P50 Double the Number of Vertical Injectors	Testing well configuration

**RESULTS DEMONSTRATION**

The cumulative CO<sub>2</sub> injections for each case of the upper Minnelusa Formation and Qingshankou–Yaojia system are summarized respectively in Figures B-7 and B-8. All of the test results in this section were organized by case and followed the images for CO<sub>2</sub> footprint (total gas per unit area), pressure difference (current pressure minus initial pressure) after 50 years, when CO<sub>2</sub> injection ended, and pressure difference after 100 years (50 years of injection plus 50 years postinjection) for both formations (Figures B-9 to B-80). Gas per unit area was used to show the CO<sub>2</sub> footprint because it creates an easy-to-understand visual. The unit of measurement is length of gas per unit area. It is important to note that, in some of the figures showing pressure difference, negative pressures are shown. This is an edge effect of the simulation software and does not actually indicate that negative pressures were created.

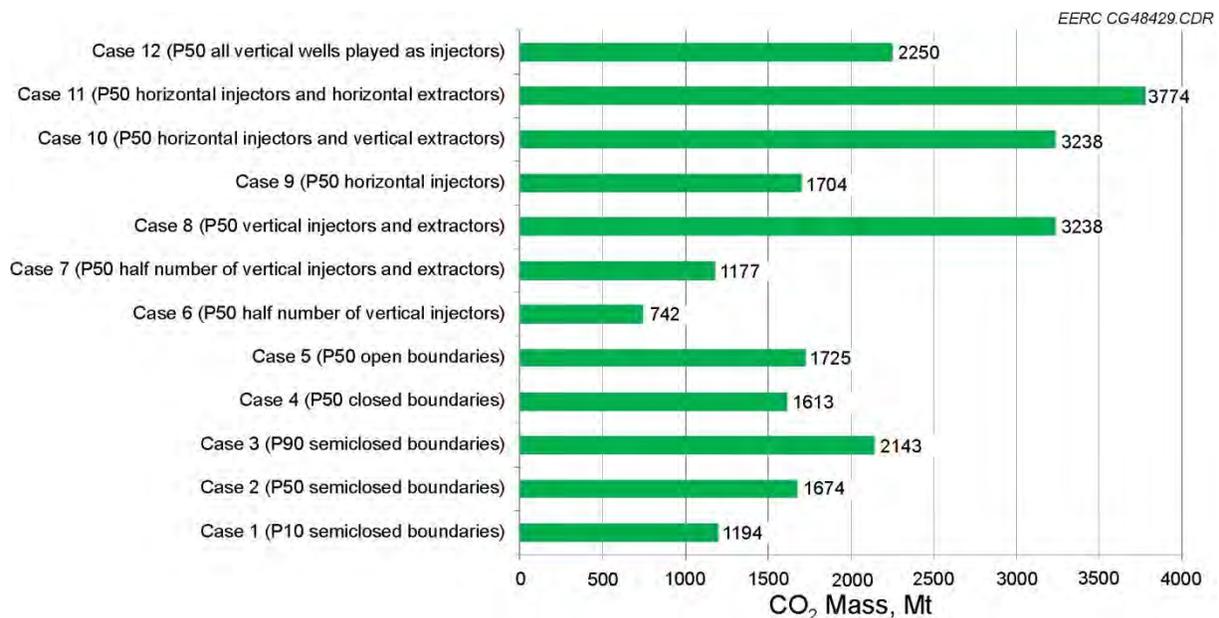


Figure B-7. Simulation results summary for the upper Minnelusa Formation.

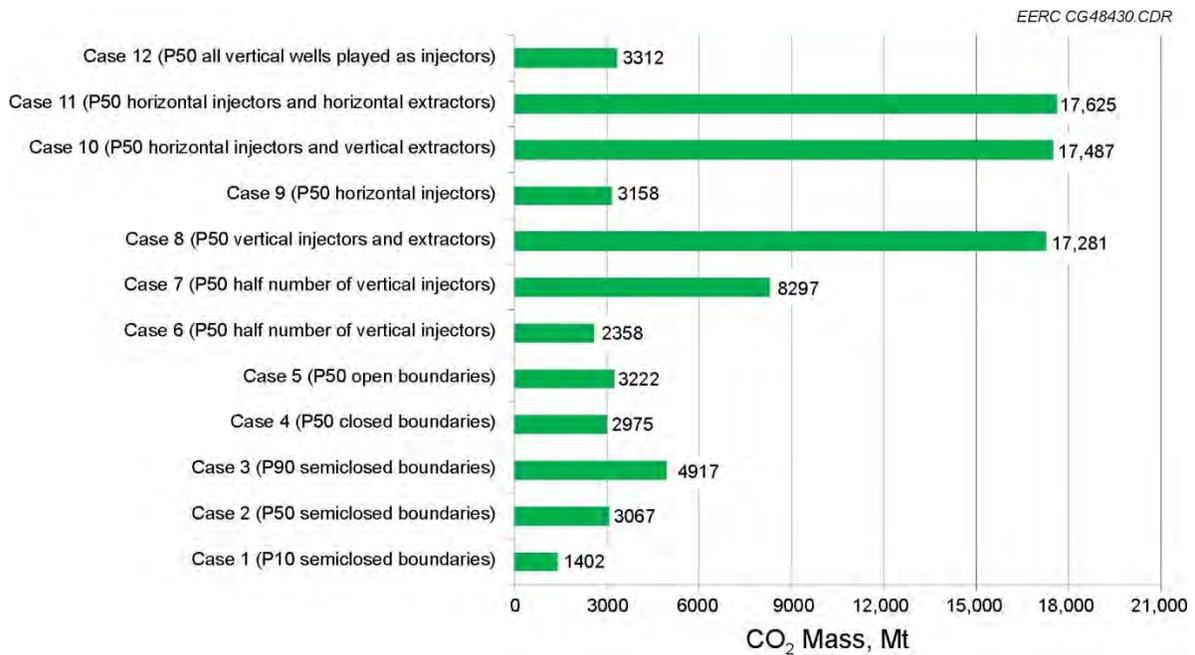


Figure B-8. Simulation results summary of Qingshankou–Yaojia system.

***Upper Minnulusa Formation:***

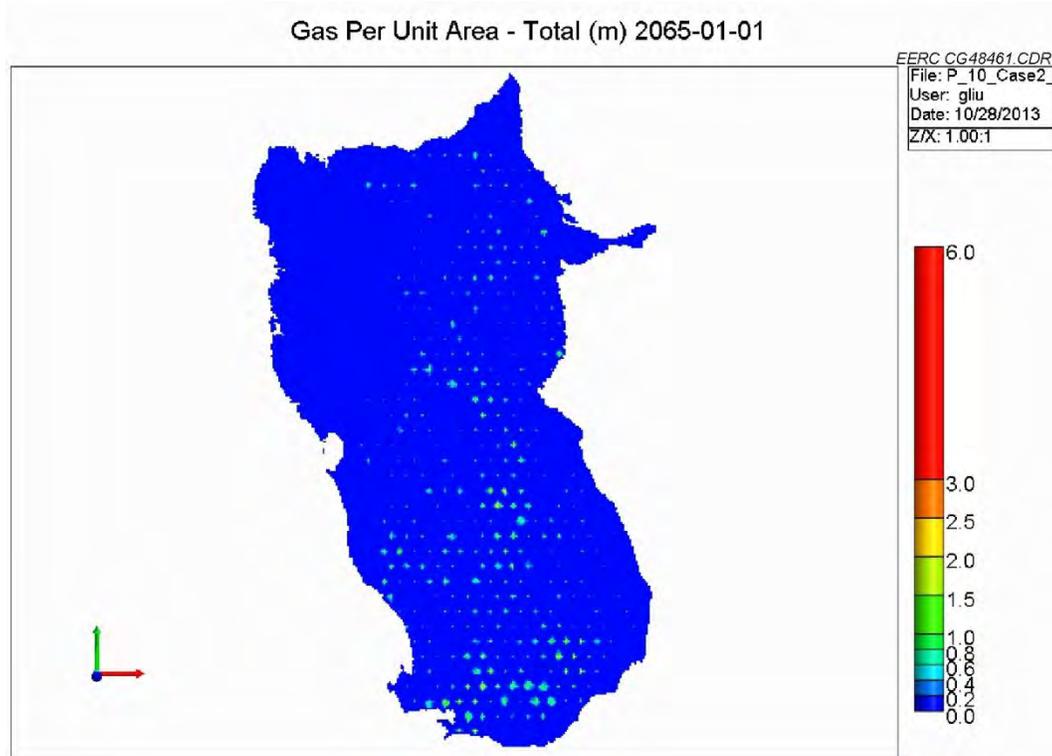


Figure B-9. Case 1: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

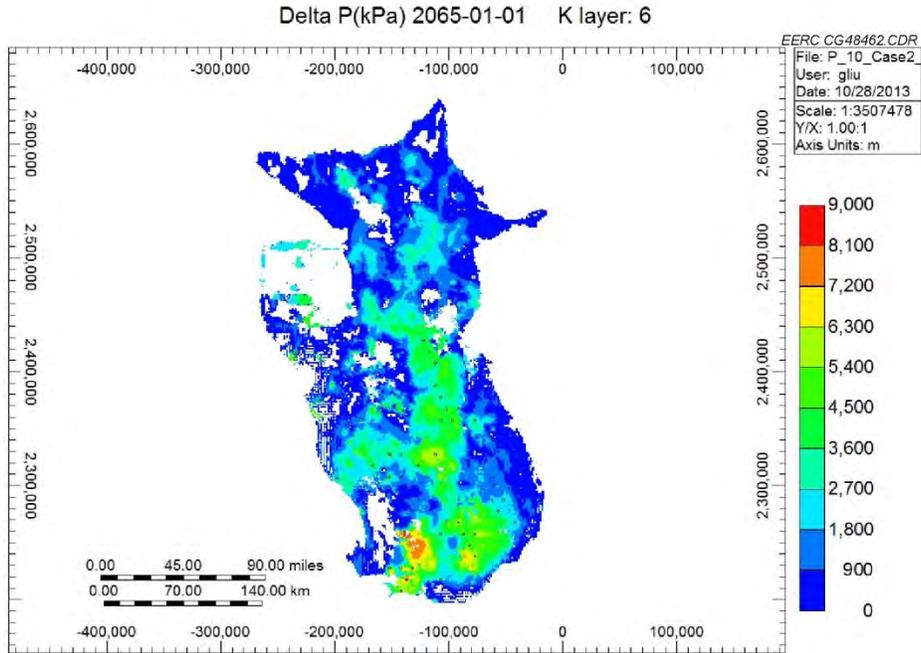


Figure B-10. Case 1: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

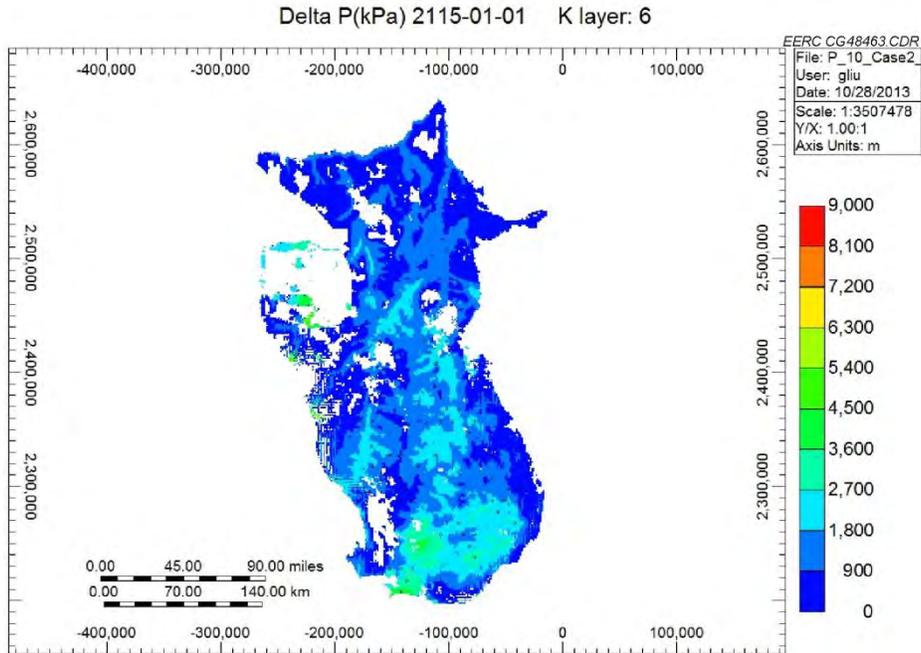


Figure B-11. Case 1: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

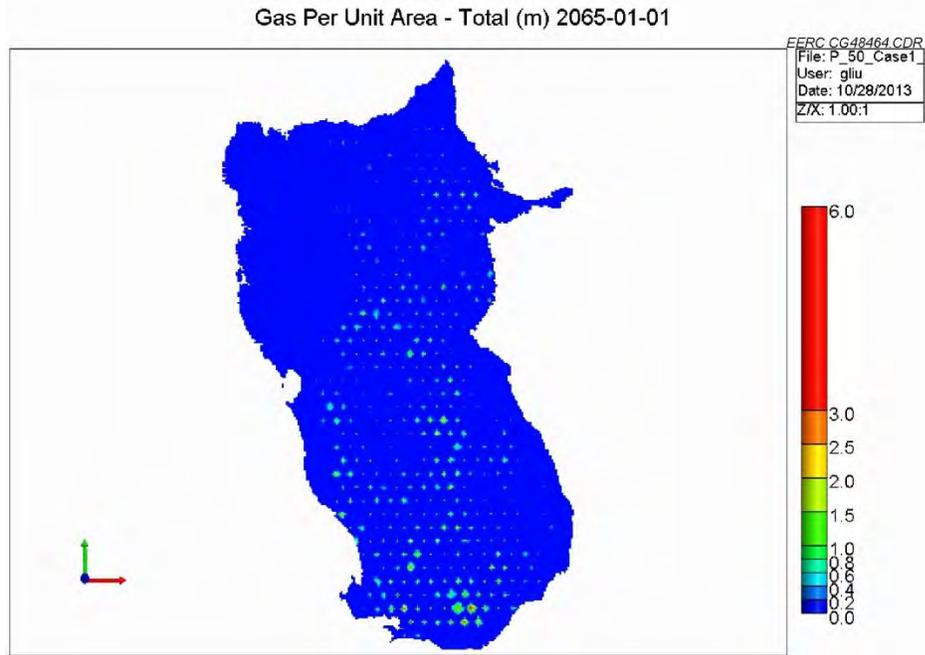


Figure B-12. Case 2: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

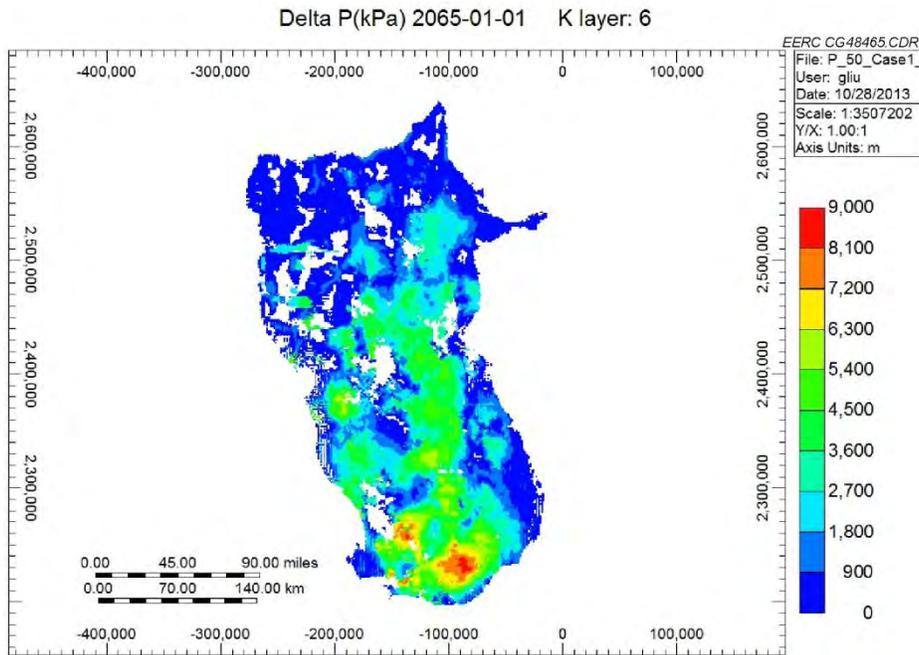


Figure B-13. Case 2: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

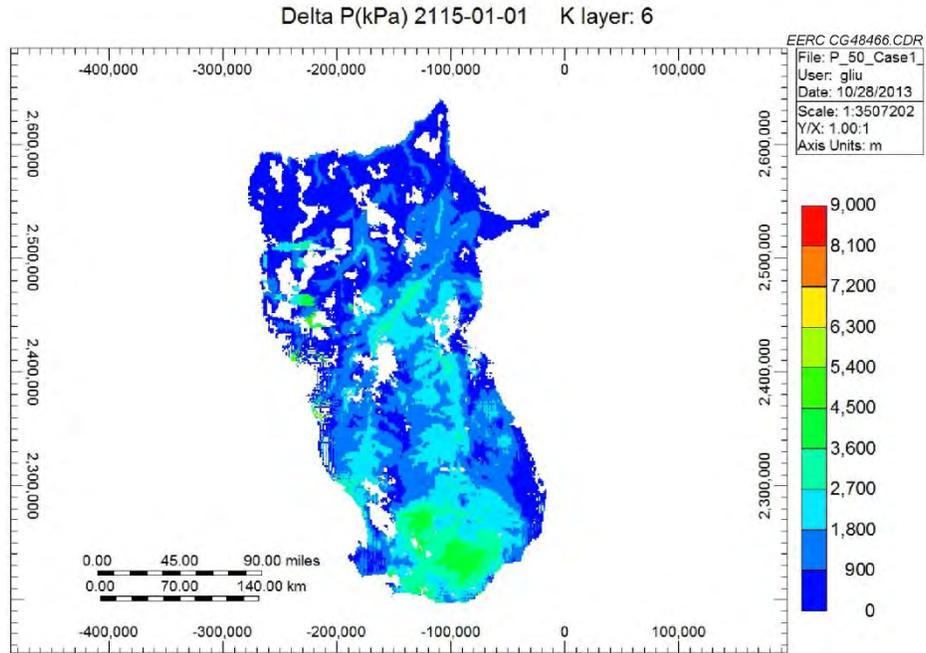


Figure B-14. Case 2: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

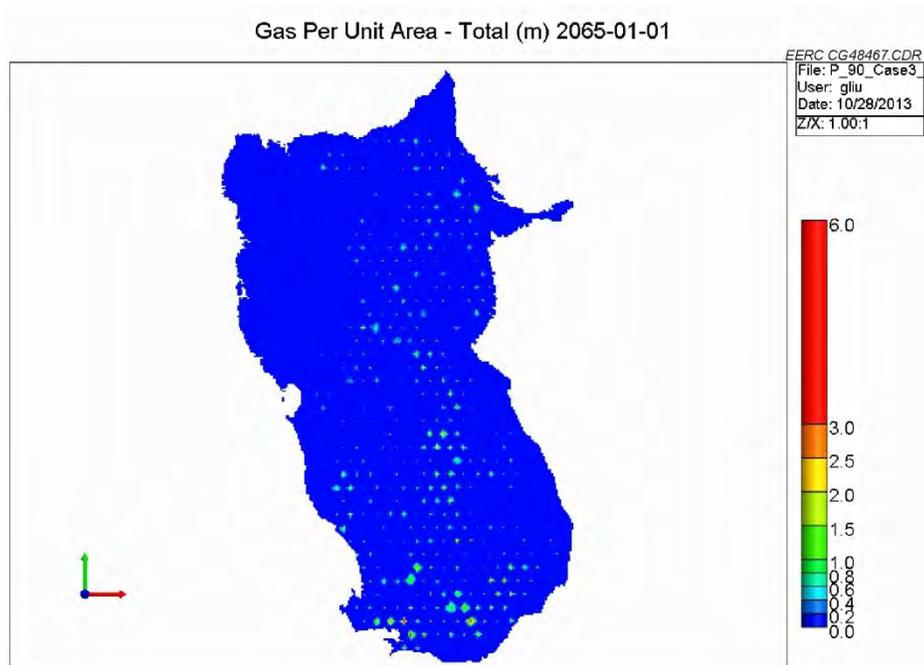


Figure B-15. Case 3: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

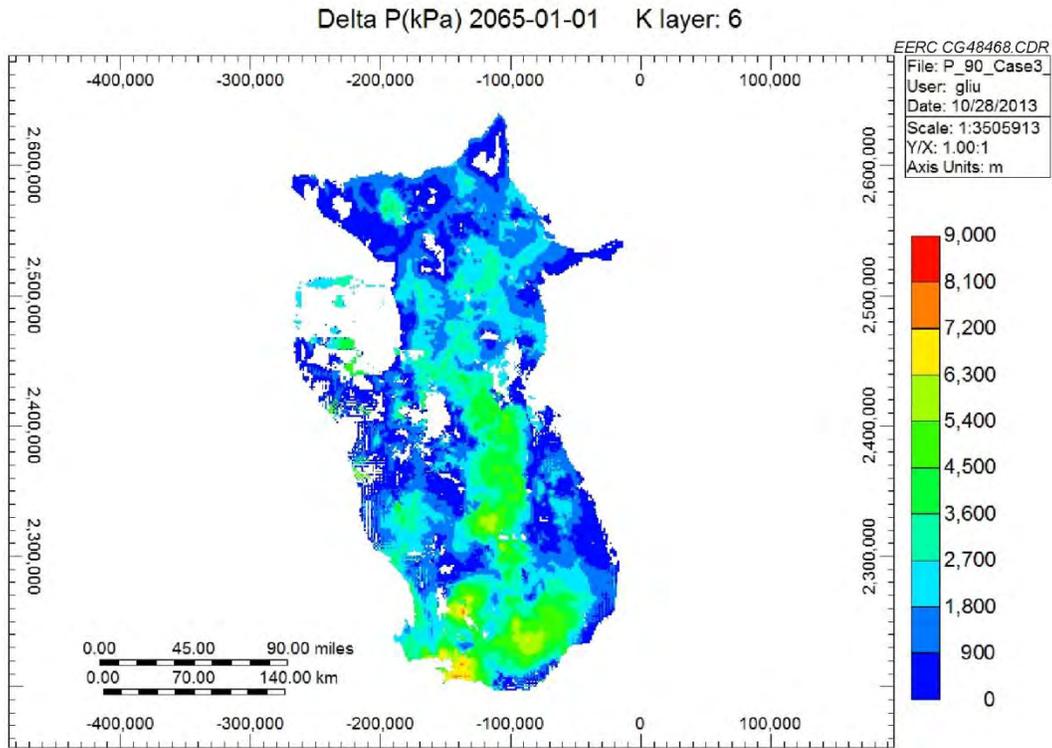


Figure B-16. Case 3: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

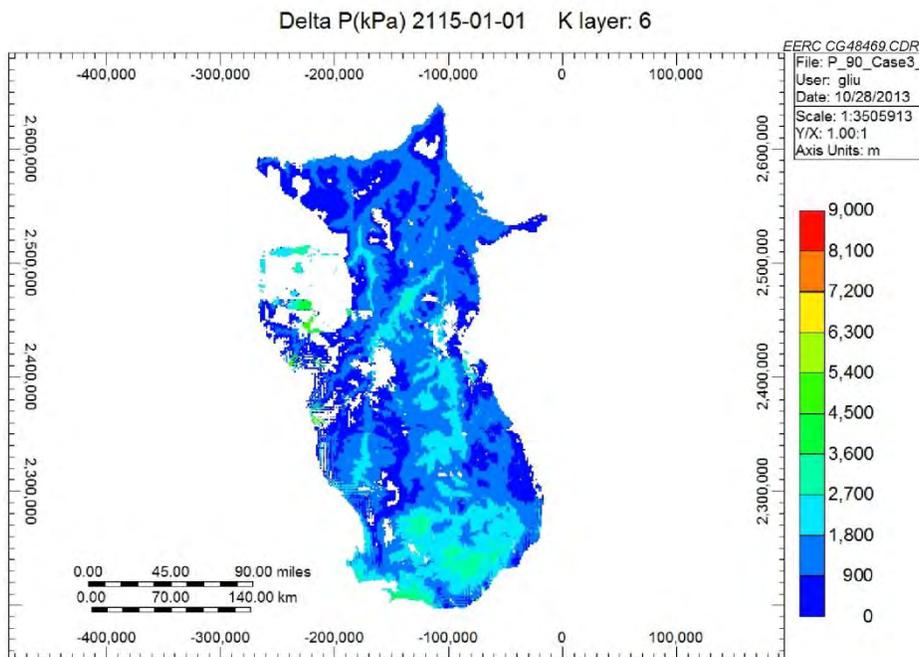


Figure B-17. Case 3: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

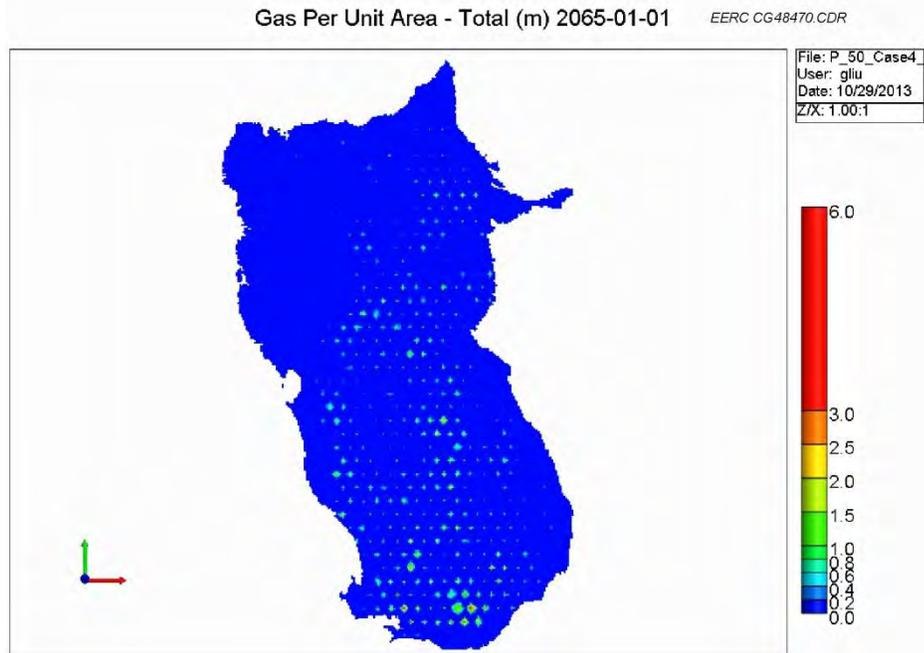


Figure B-18. Case 4: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

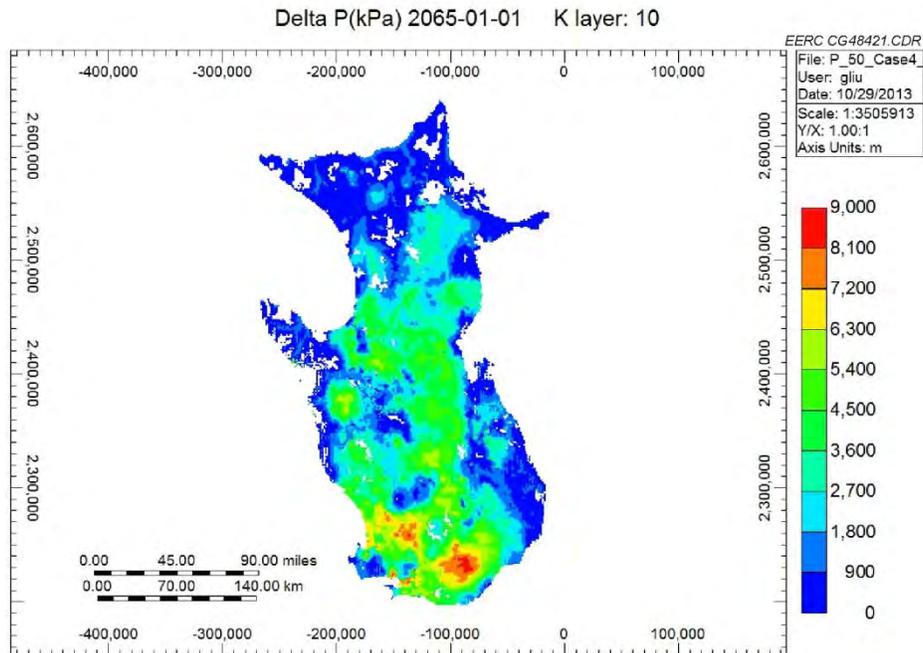


Figure B-19. Case 4: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

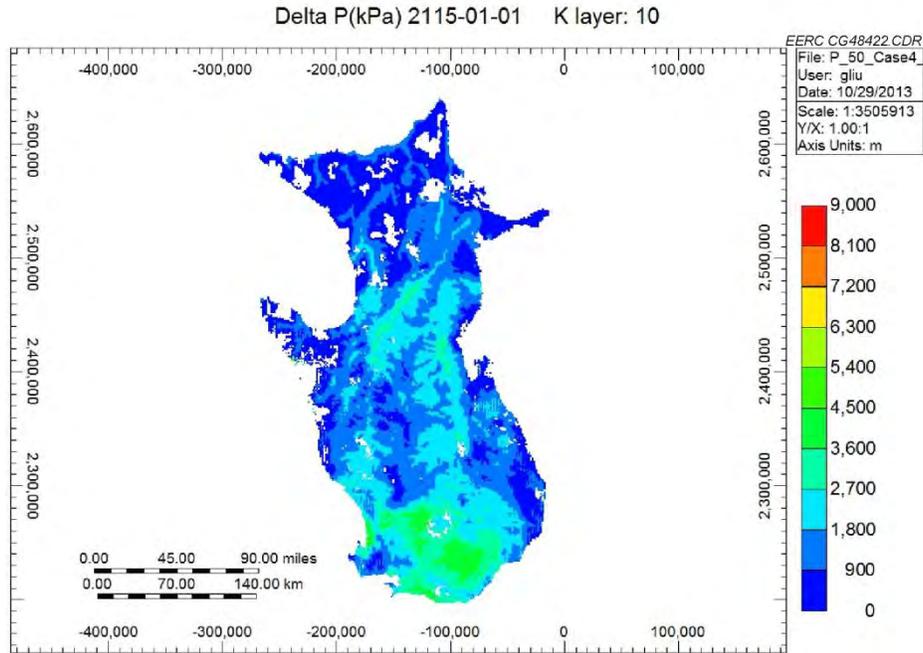


Figure B-20. Case 4: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

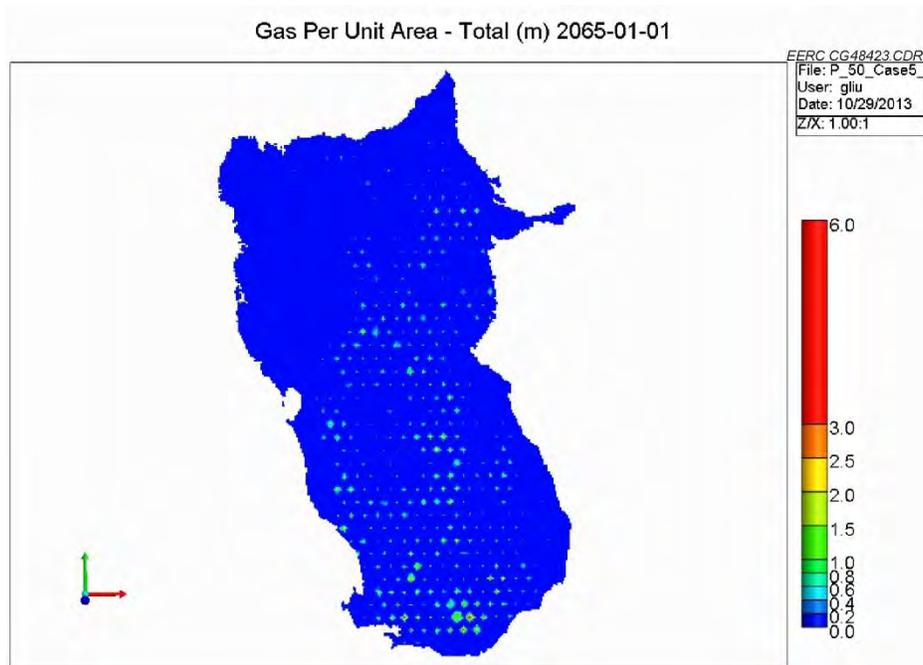


Figure B-21. Case 5: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

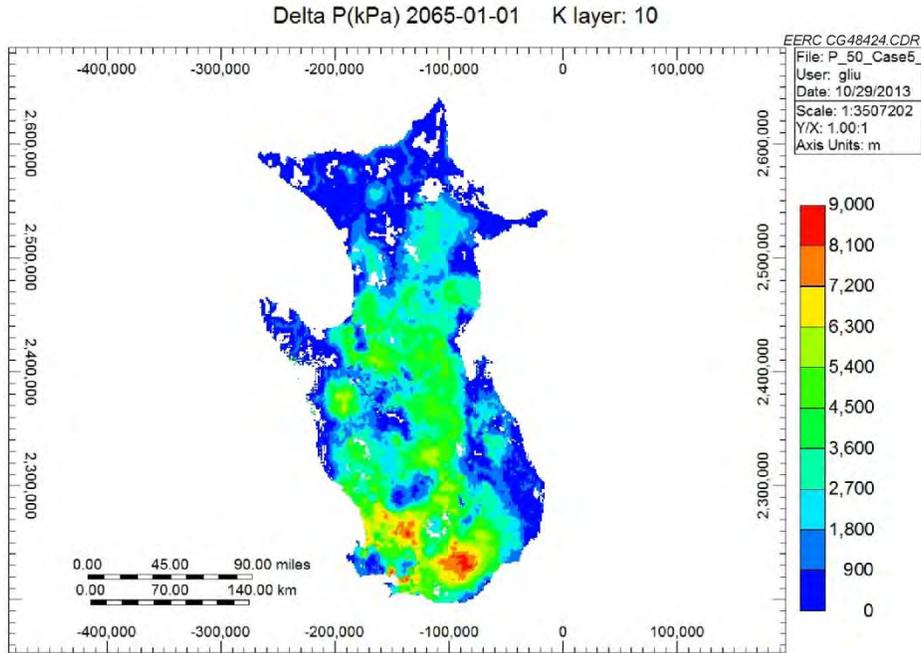


Figure B-22. Case 5: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

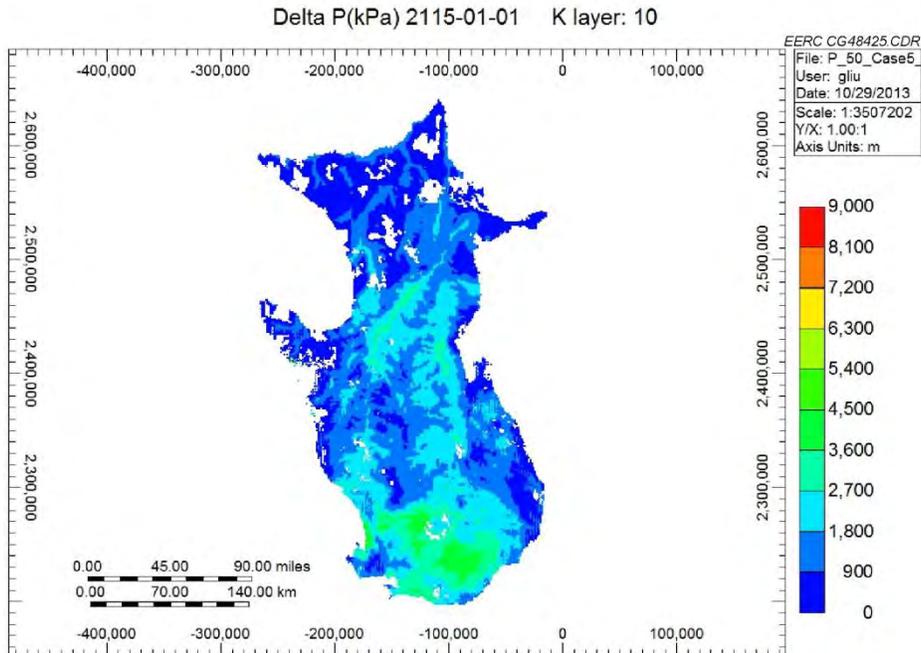


Figure B-23. Case 5: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

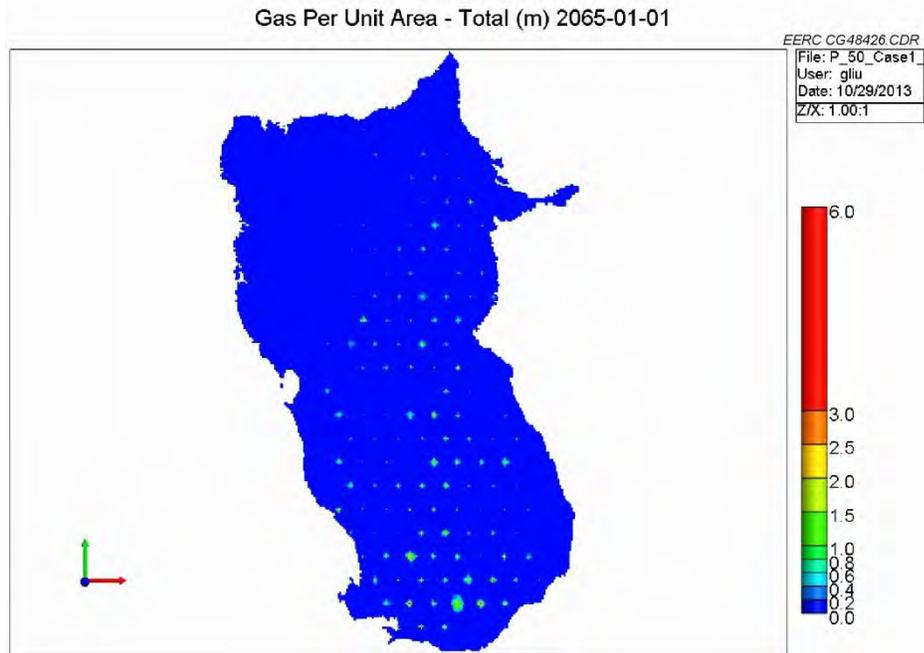


Figure B-24. Case 6: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

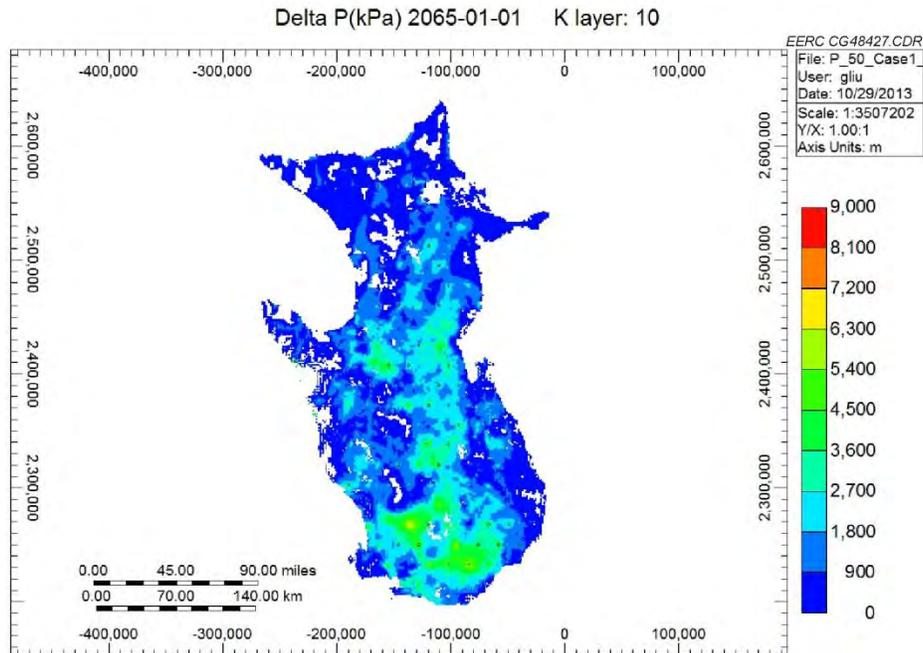


Figure B-25. Case 6: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

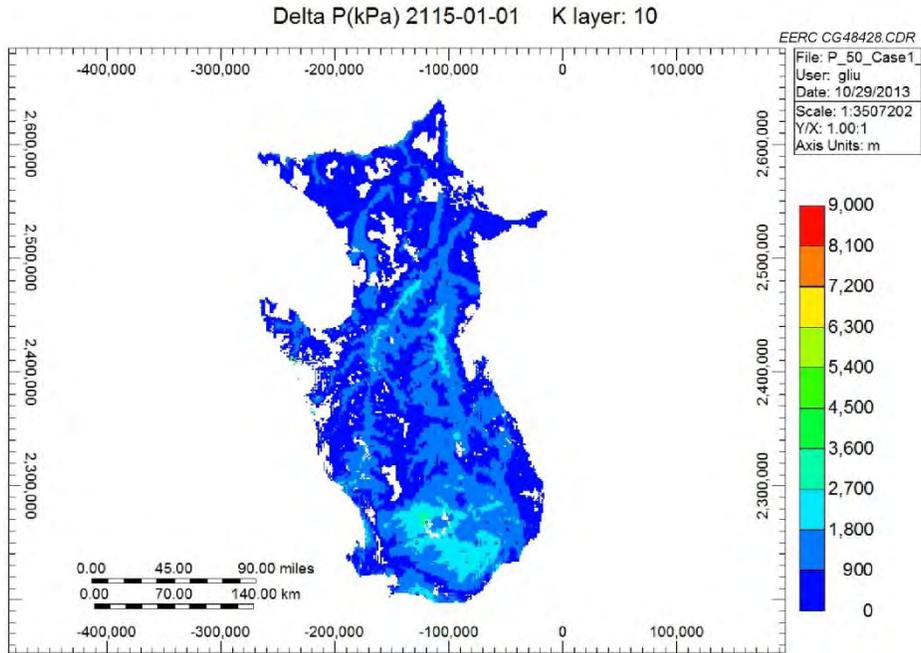


Figure B-26. Case 6: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

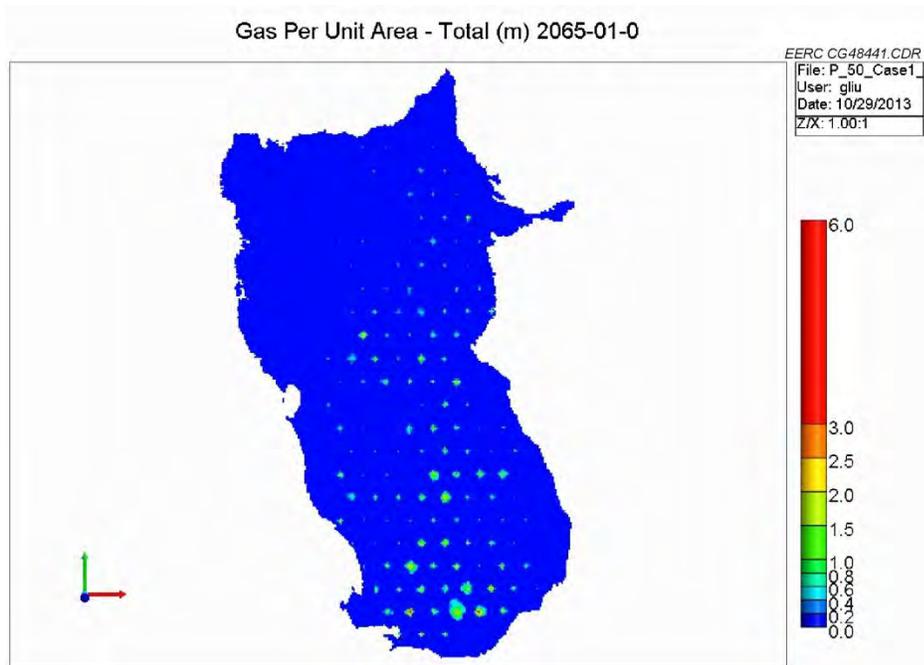


Figure B-27. Case 7: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

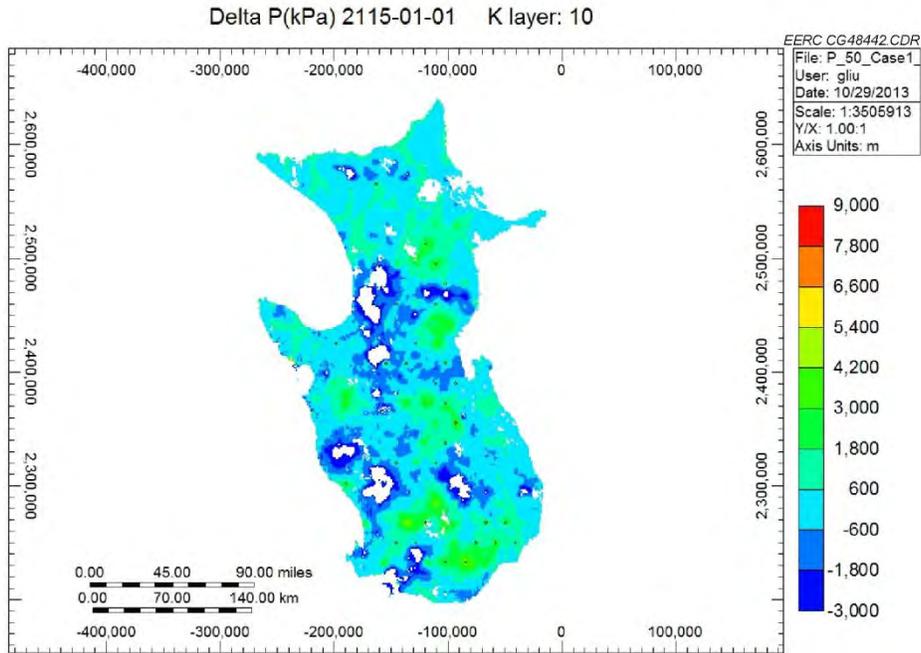


Figure B-28. Case 7: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

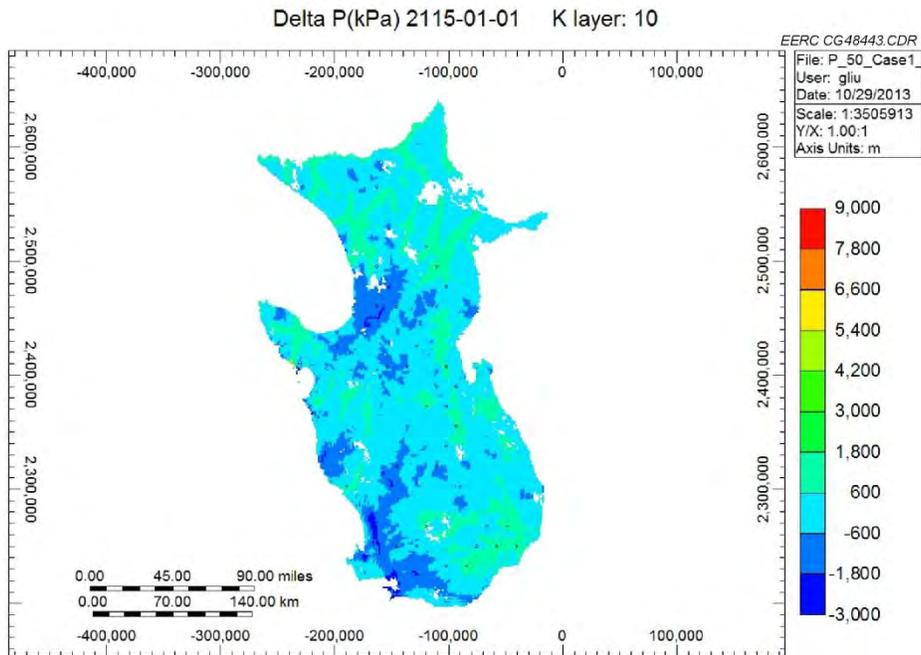


Figure B-29. Case 7: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

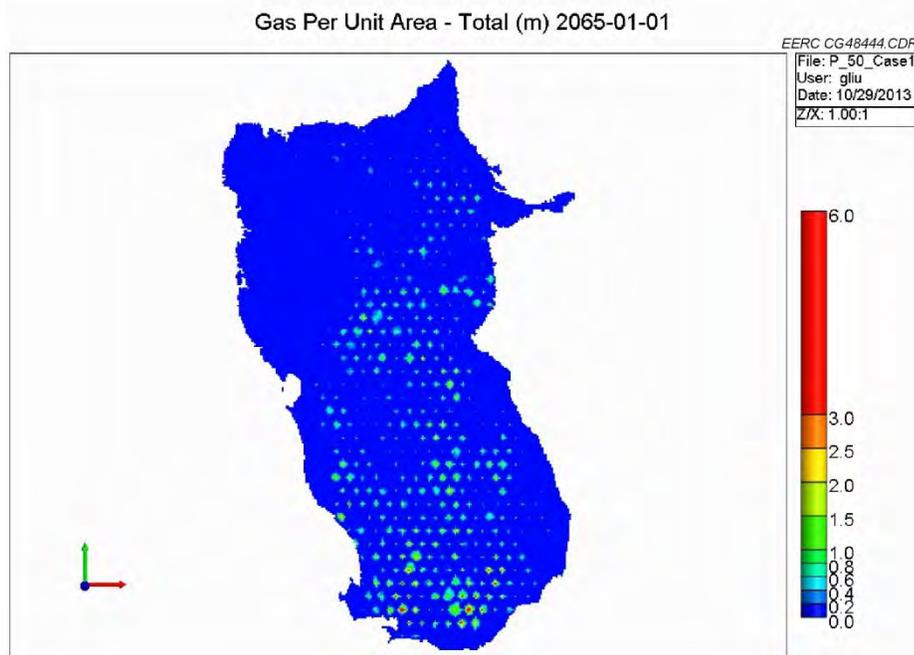


Figure B-30. Case 8: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

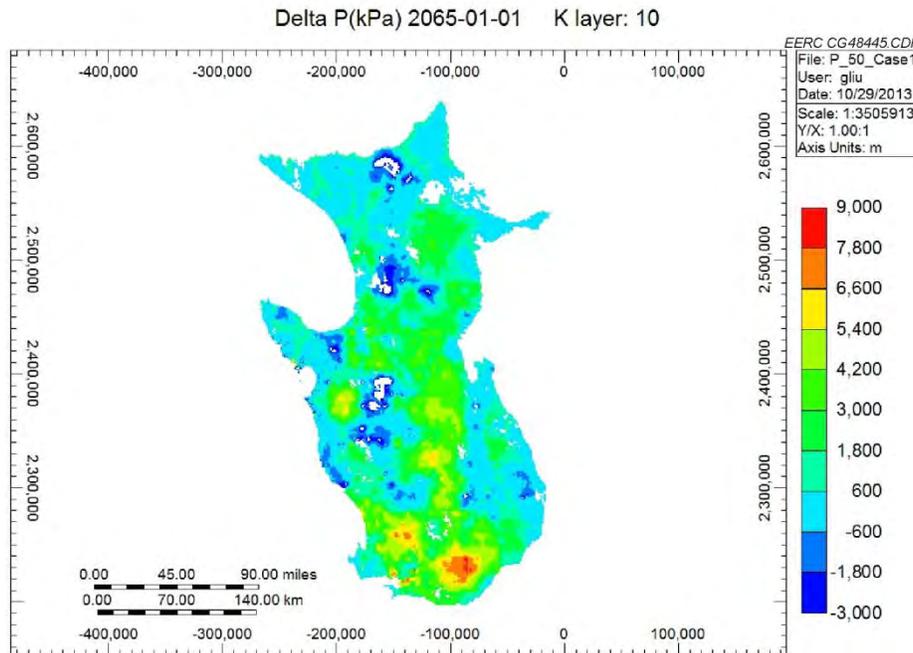


Figure B-31. Case 8: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

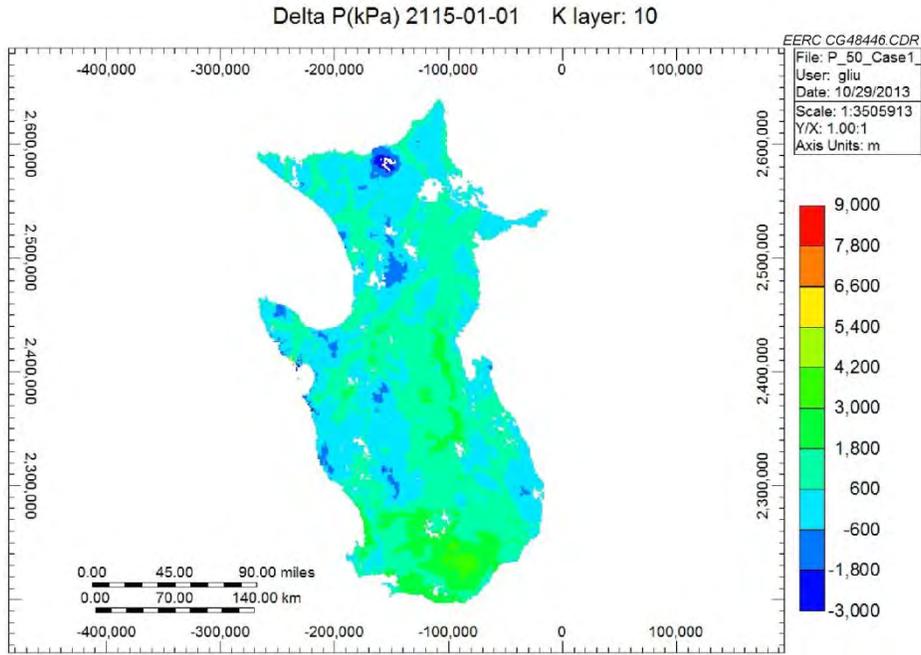


Figure B-32. Case 8: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

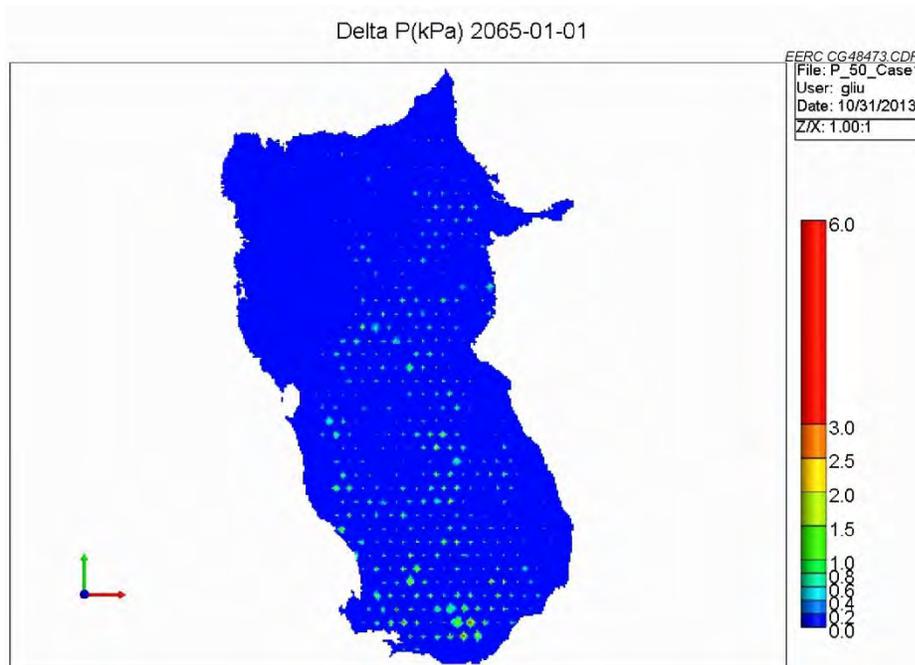


Figure B-33. Case 9: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

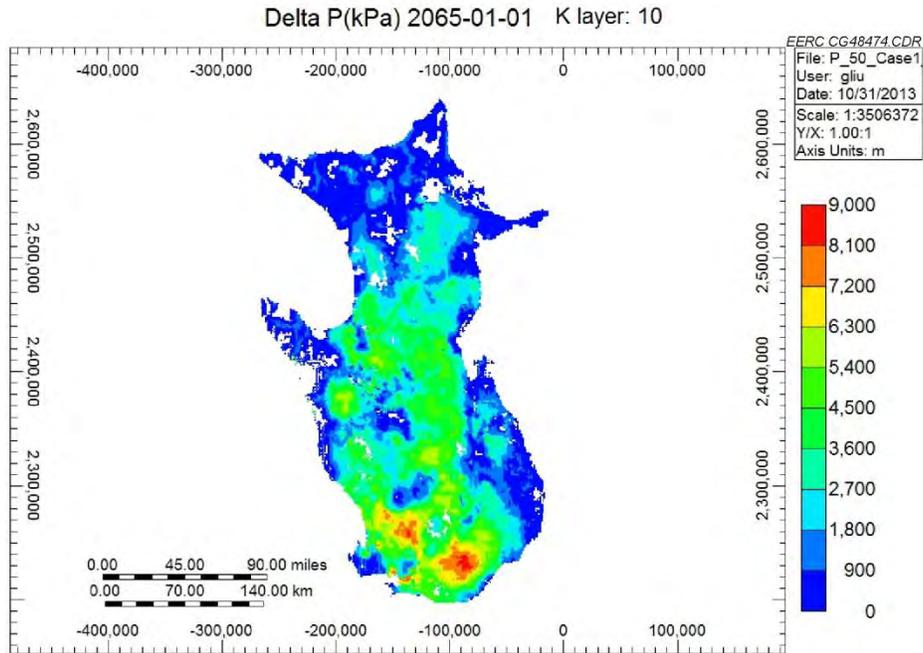


Figure B-34. Case 9: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

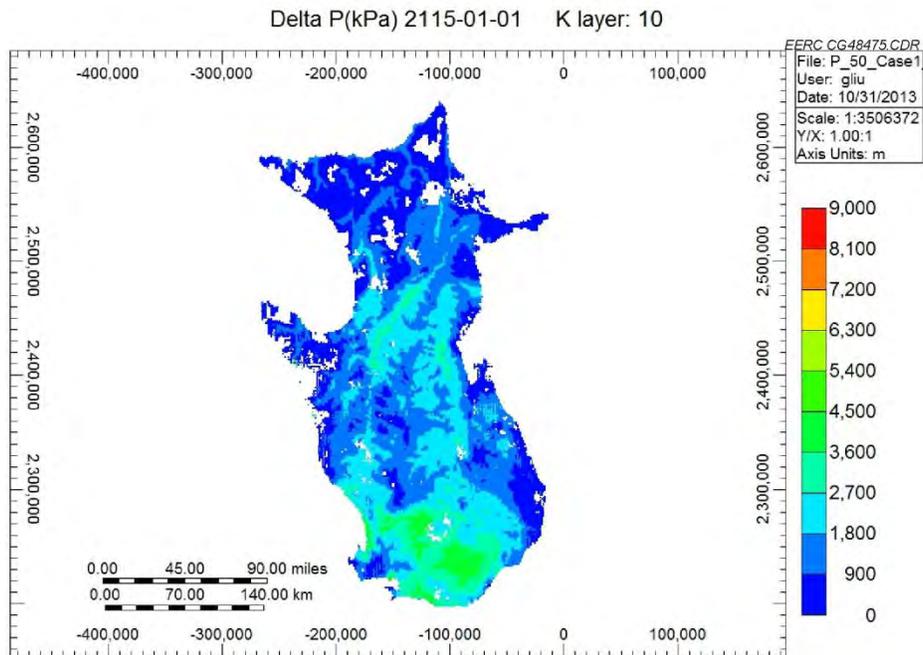


Figure B-35. Case 9: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

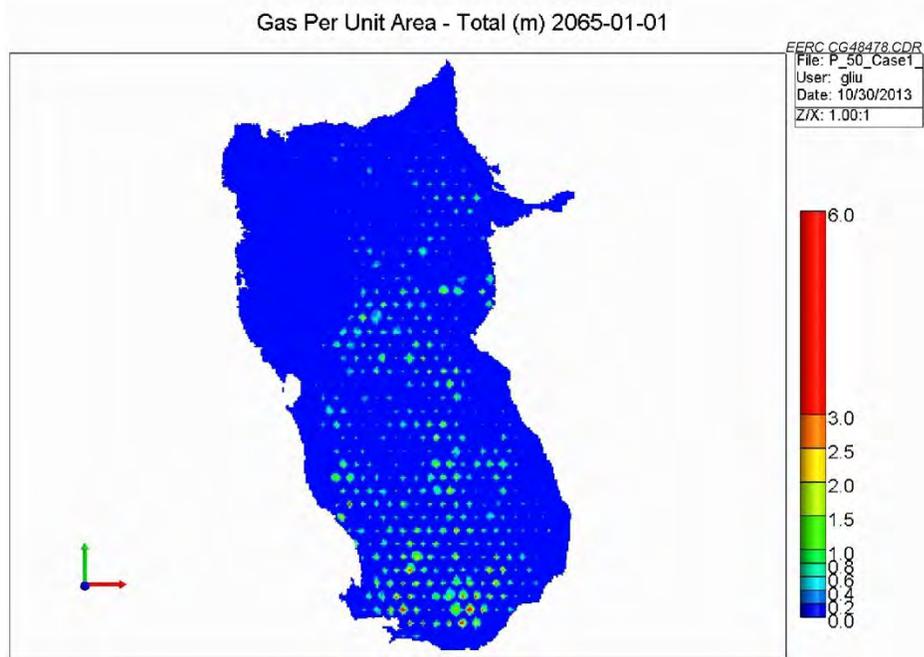


Figure B-36. Case 10: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

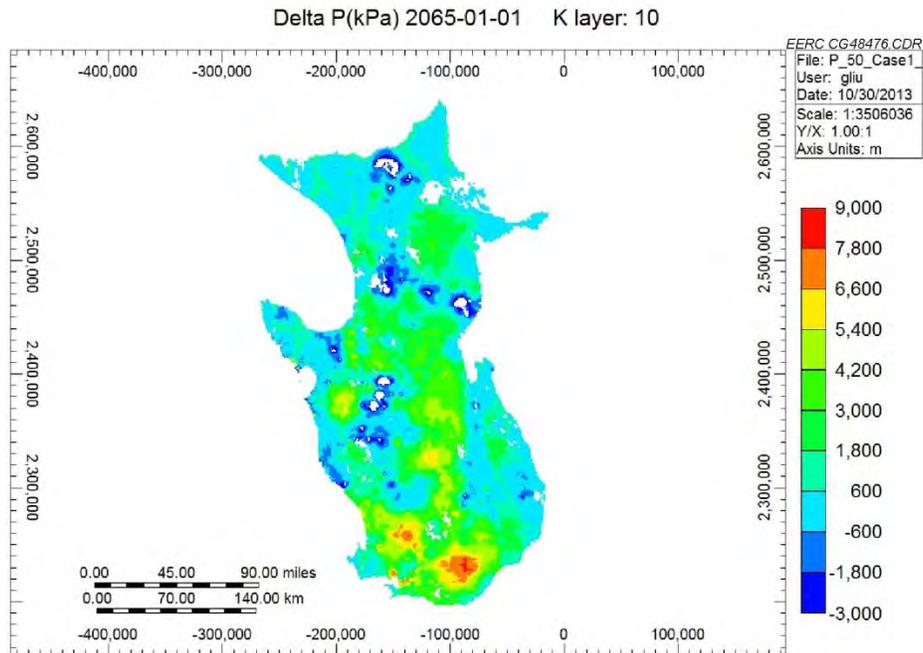


Figure B-37. Case 10: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

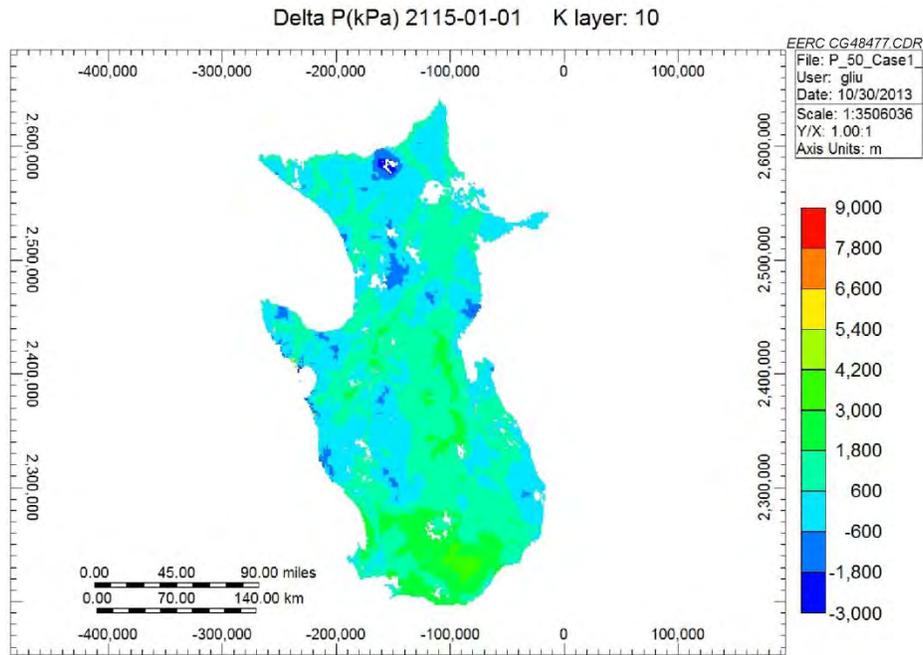


Figure B-38. Case 10: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

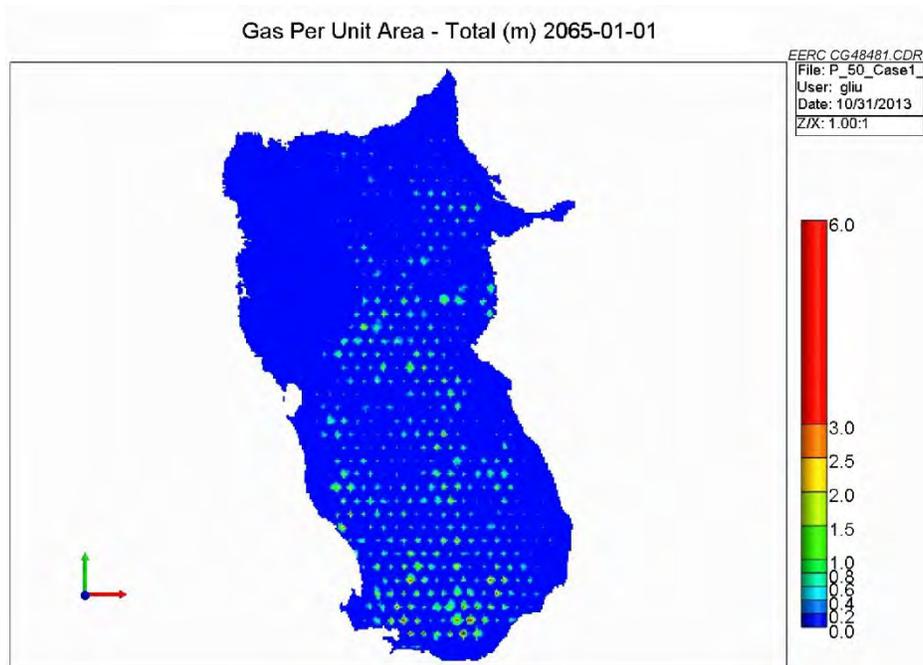


Figure B-39. Case 11: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

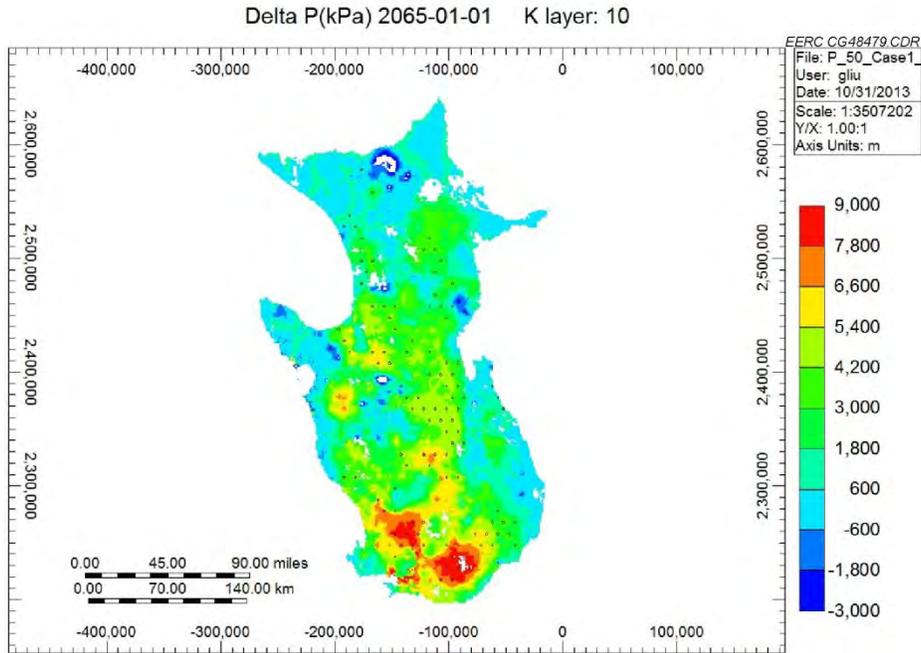


Figure B-40. Case 11: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

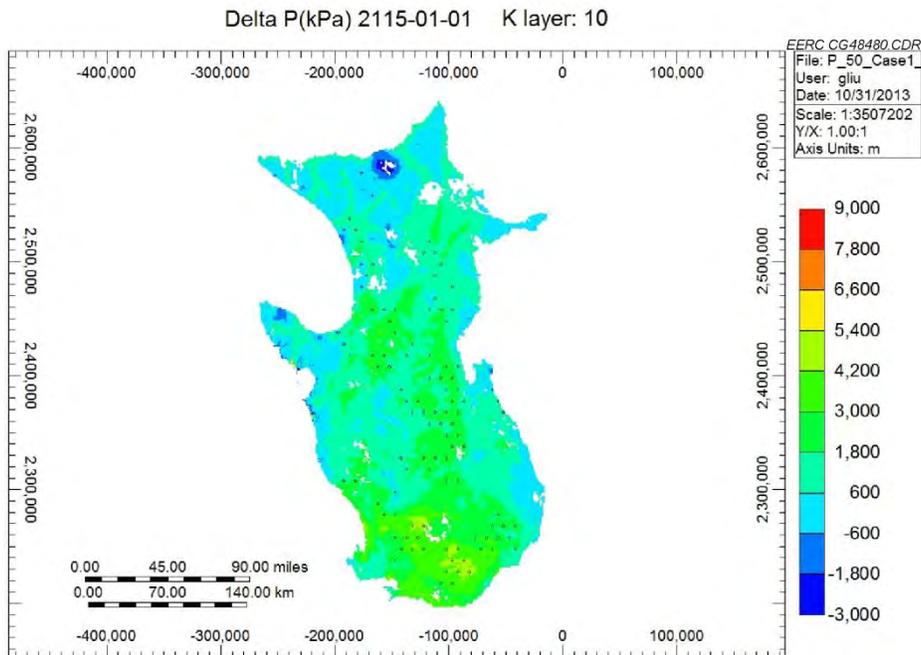


Figure B-41. Case 11: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

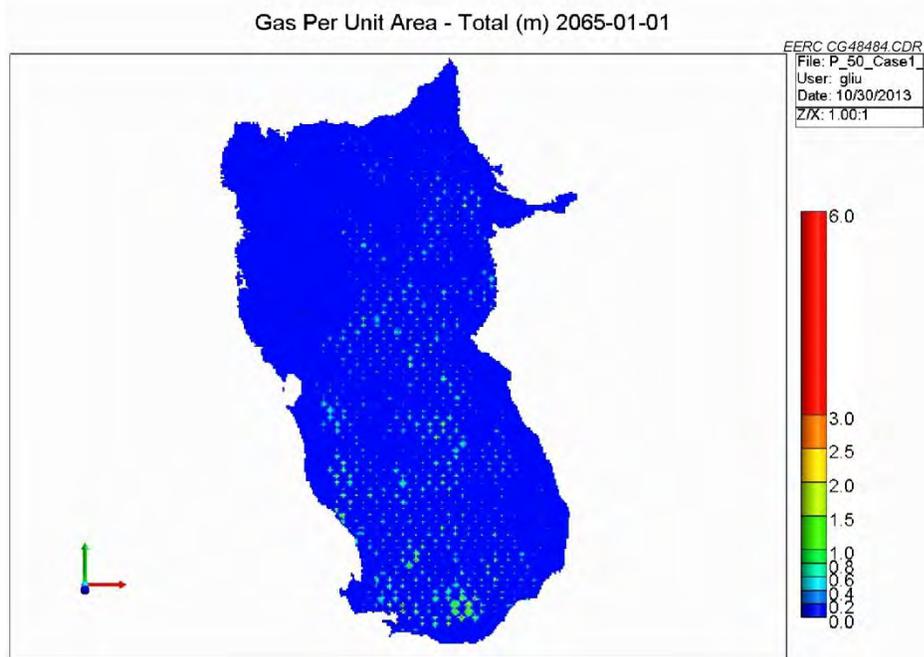


Figure B-42. Case 12: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

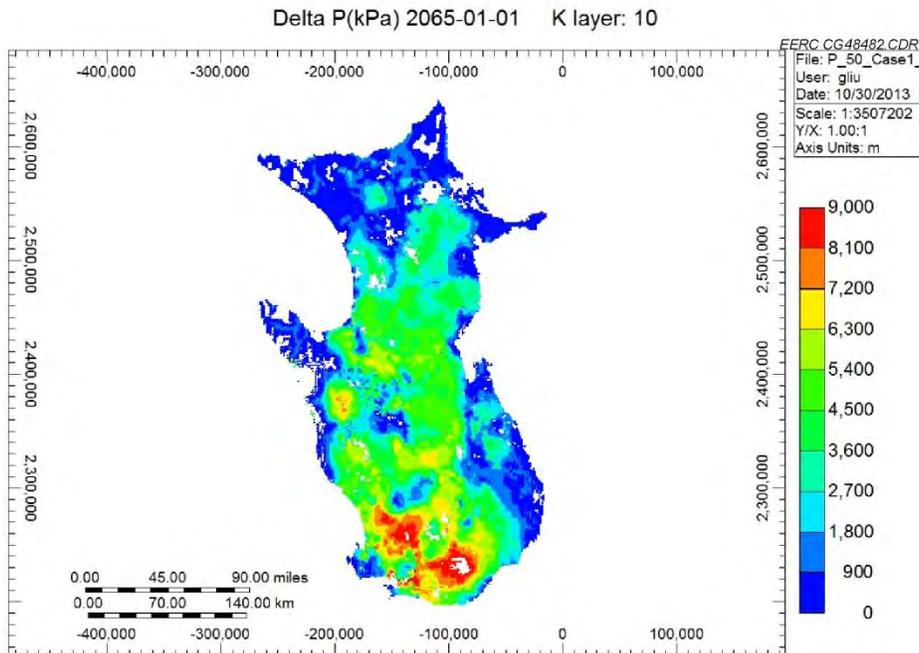


Figure B-43. Case 12: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

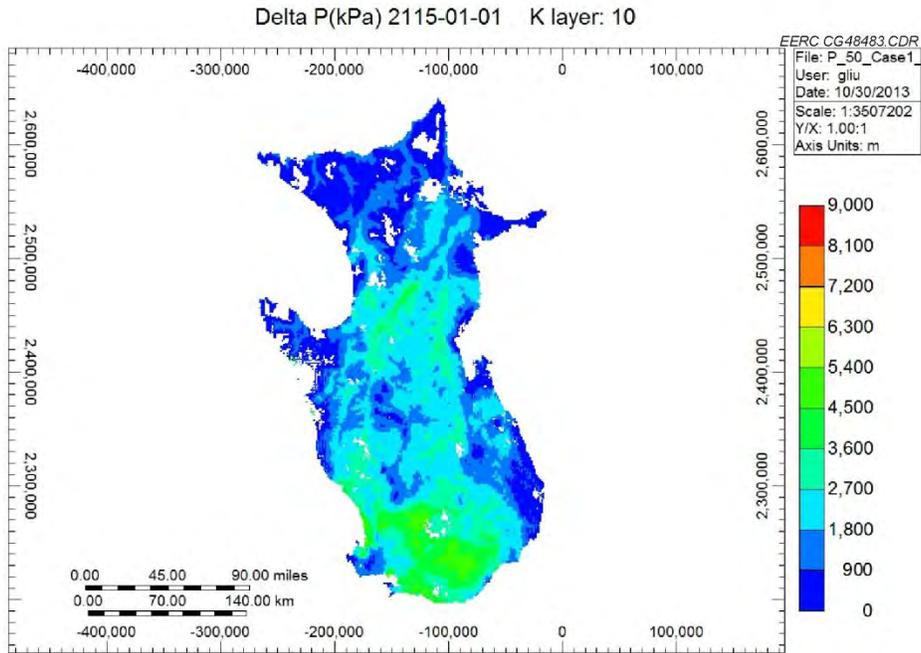


Figure B-44. Case 12: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

***Qingshankou–Yaojia System:***

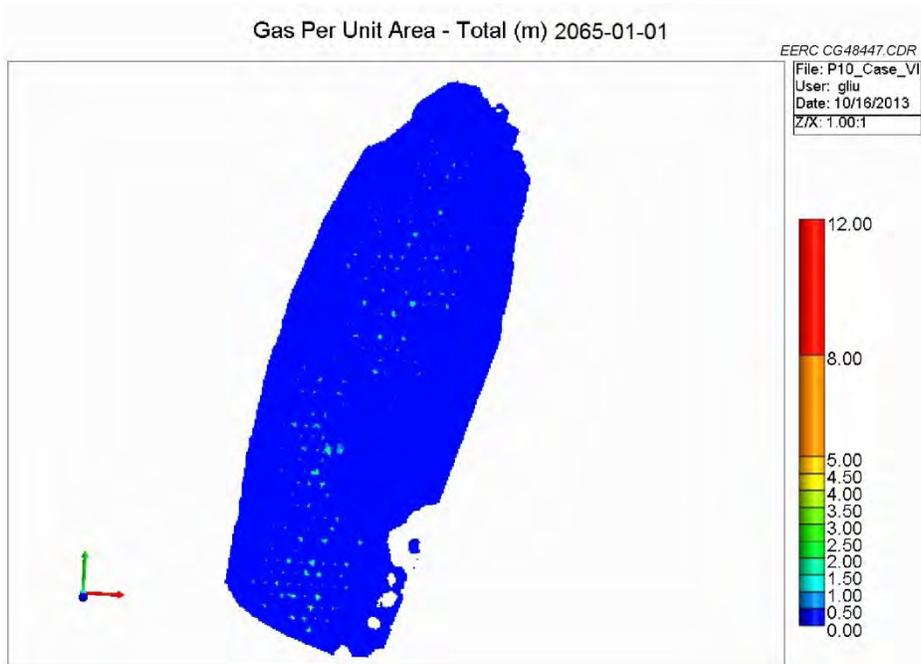


Figure B-45. Case 1: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

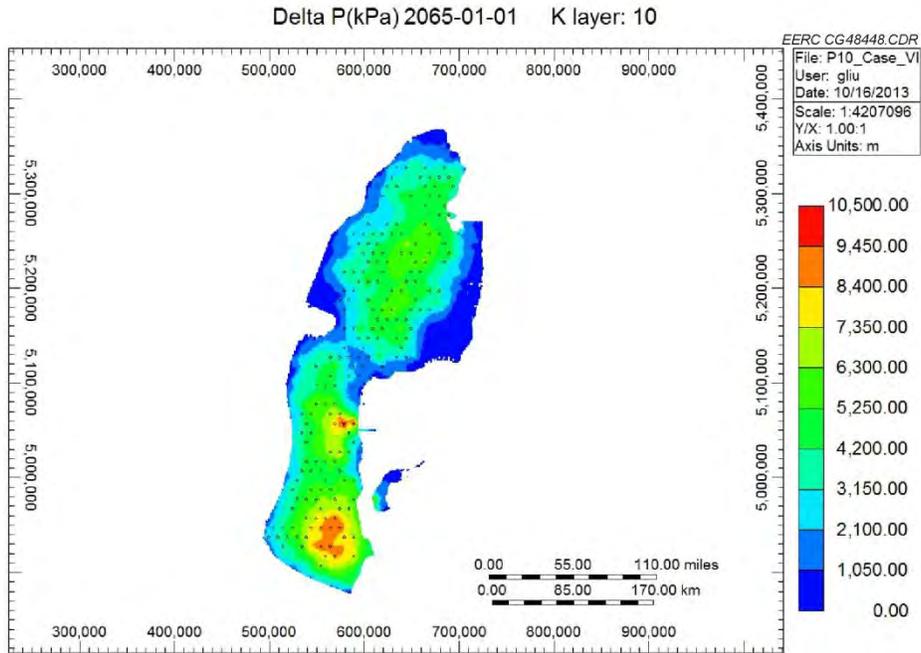


Figure B-46. Case 1: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

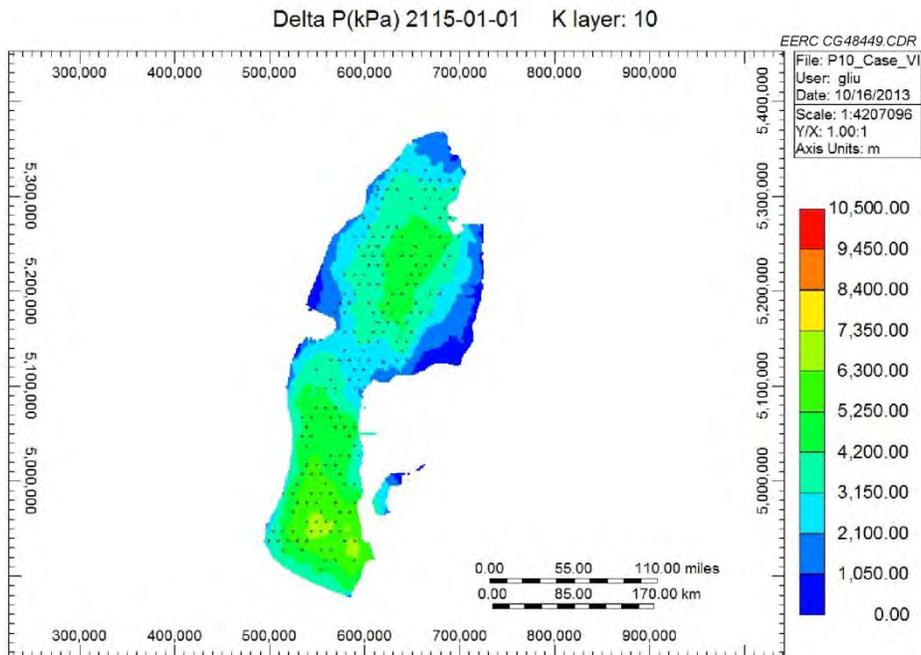


Figure B-47. Case 1: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

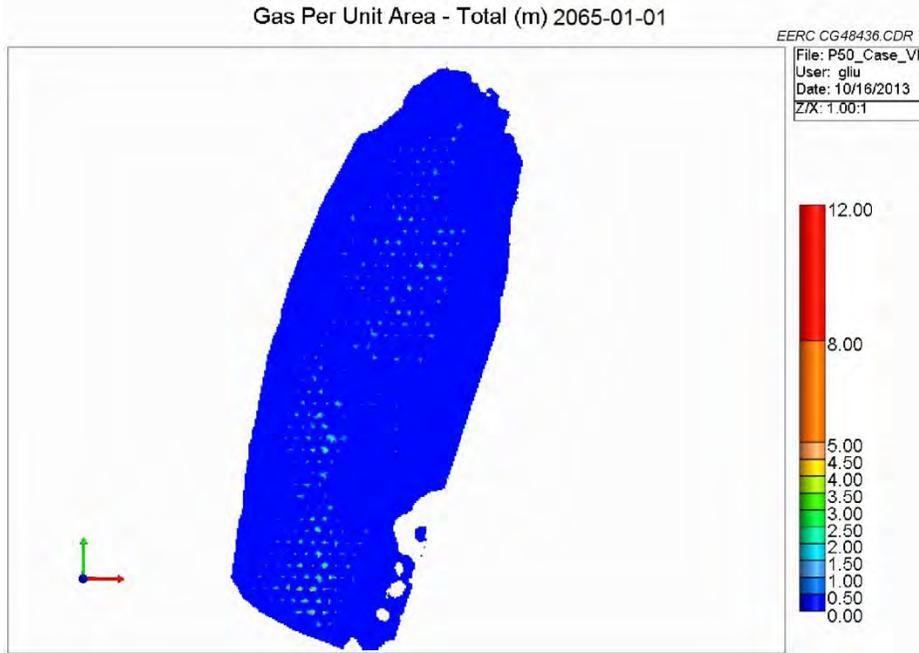


Figure B-48. Case 2: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

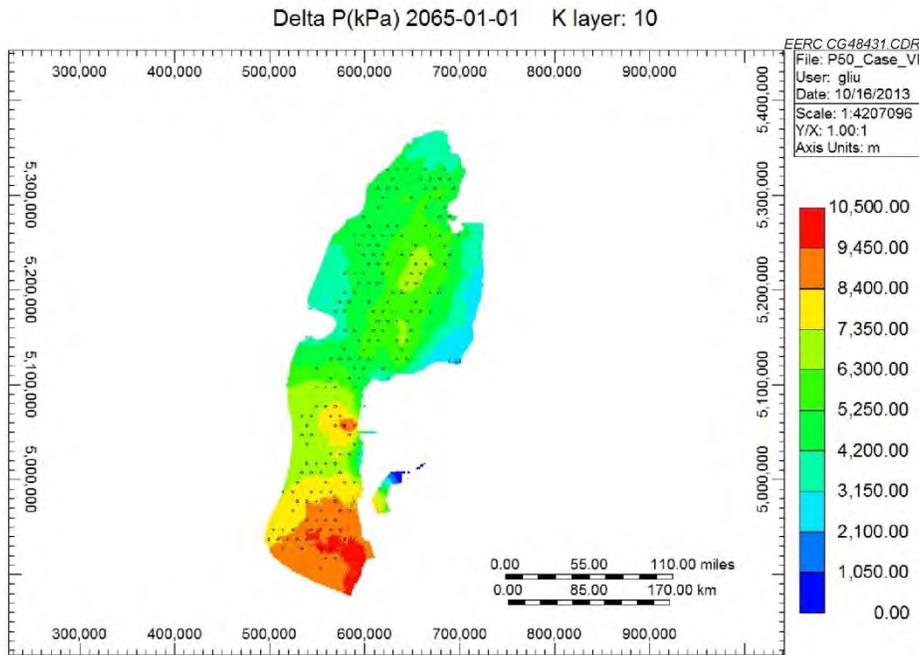


Figure B-49. Case 2: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

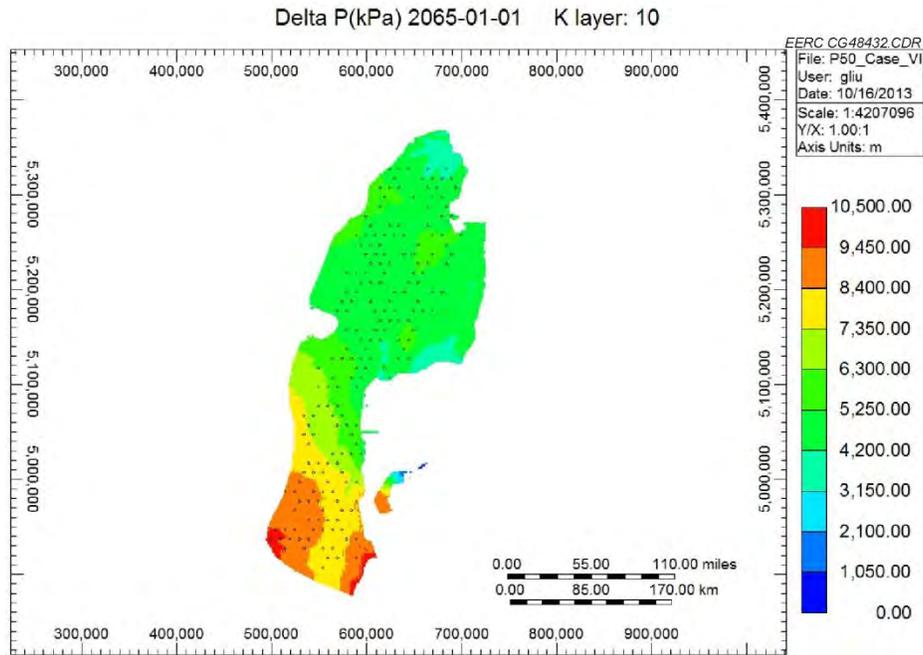


Figure B-50. Case 2: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

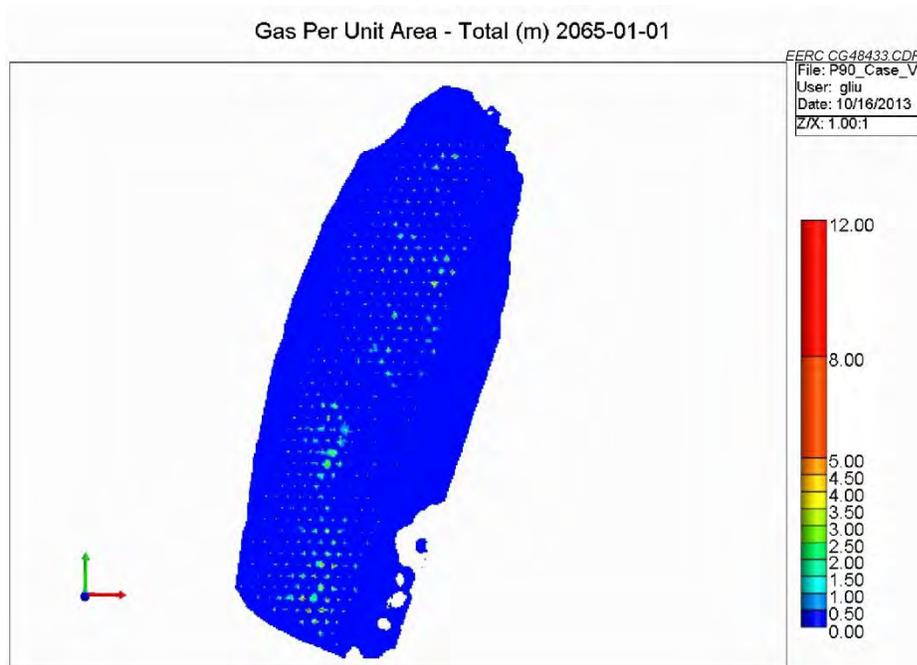


Figure B-51. Case 3: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

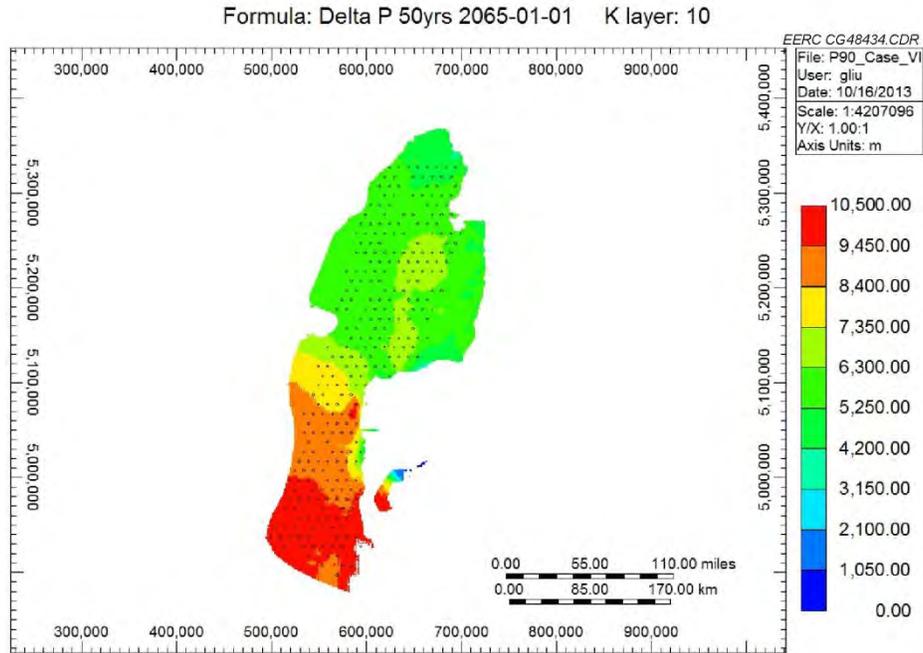


Figure B-52. Case 3: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

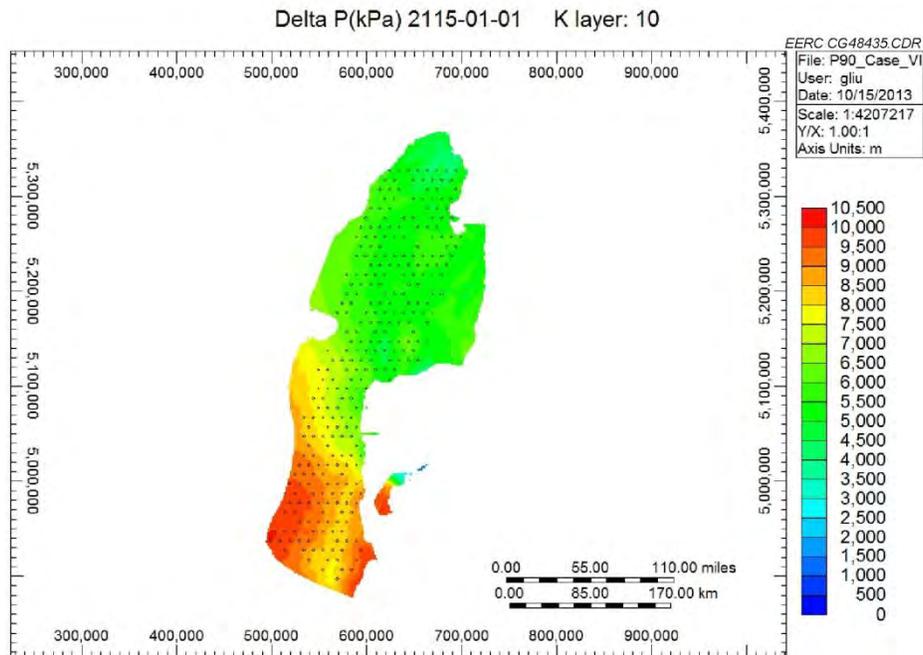


Figure B-53. Case 3: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

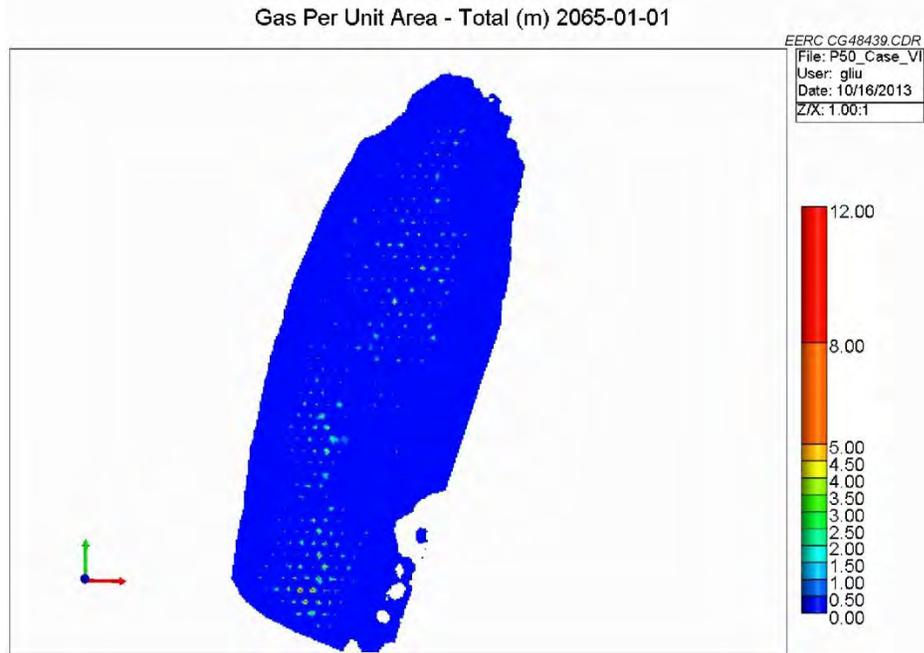


Figure B-54. Case 4: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

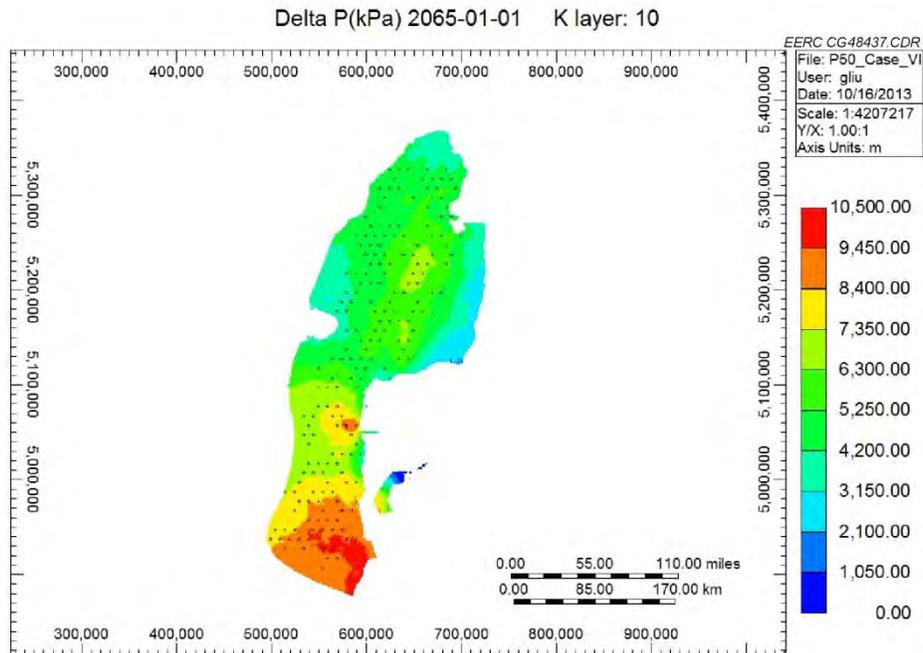


Figure B-55. Case 4: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

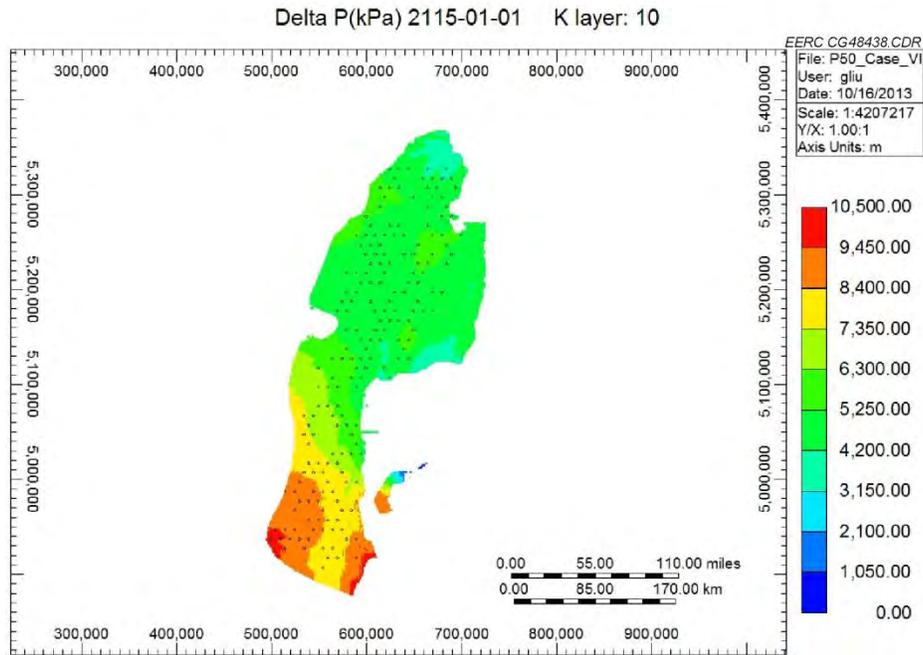


Figure B-56. Case 4: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

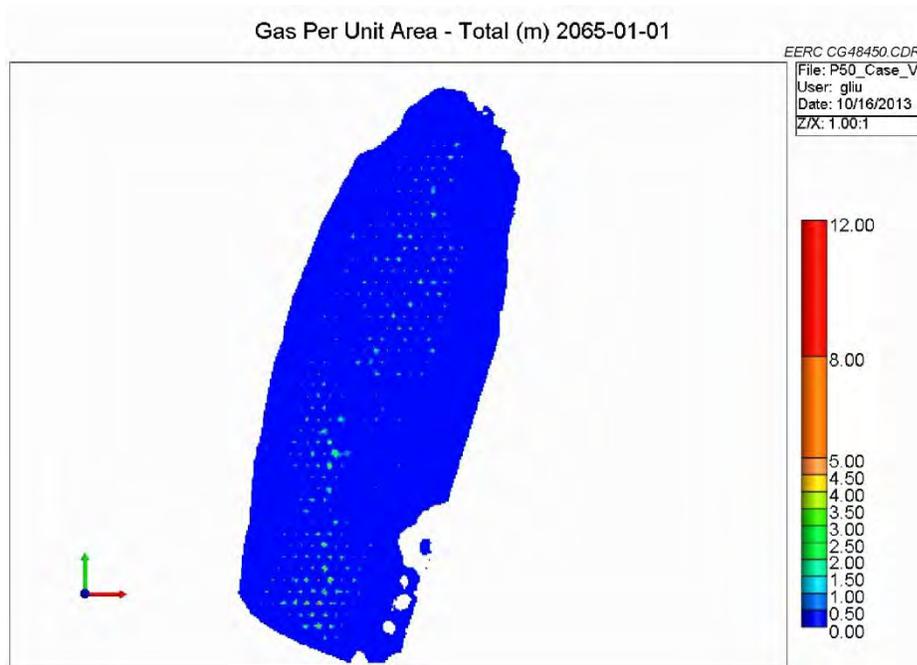


Figure B-57. Case 5: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

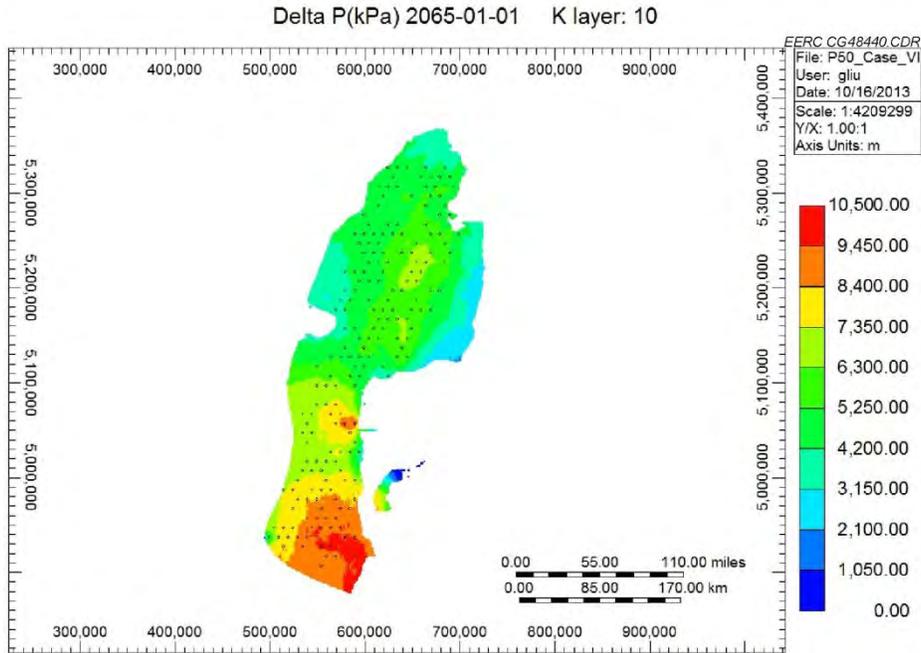


Figure B-58. Case 5: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

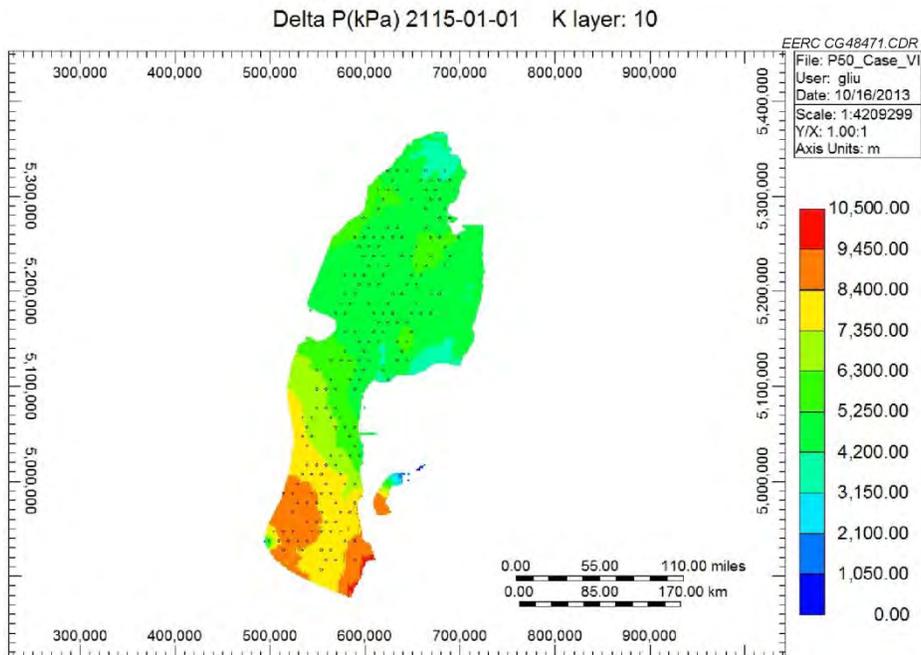


Figure B-59. Case 5: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

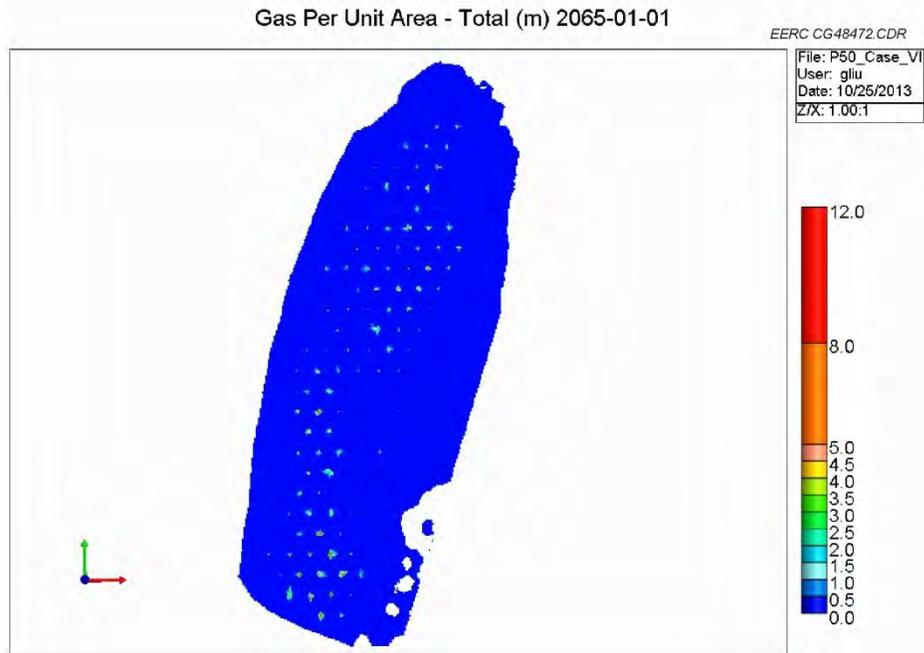


Figure B-60. Case 6: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

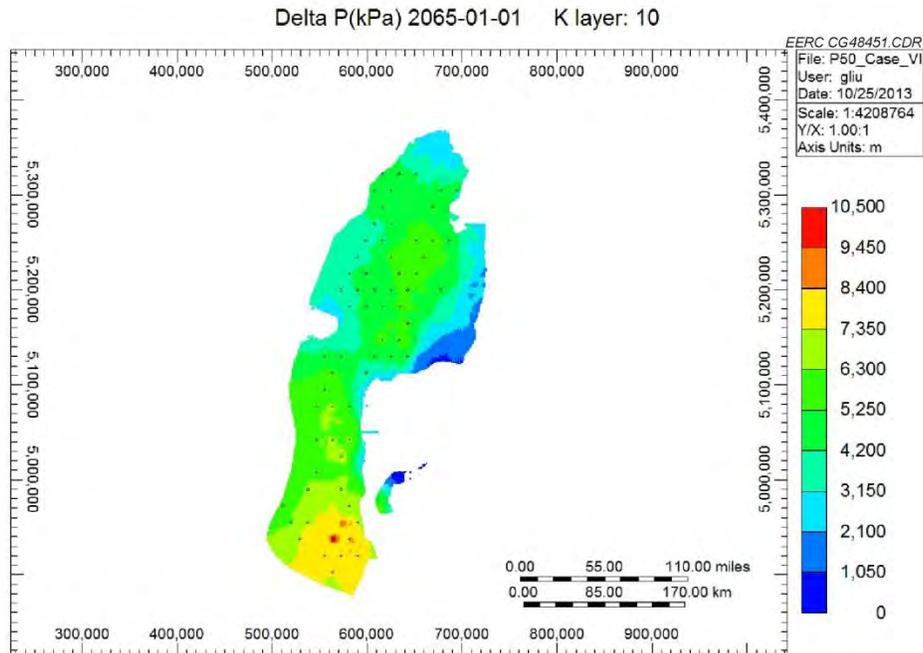


Figure B-61. Case 6: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

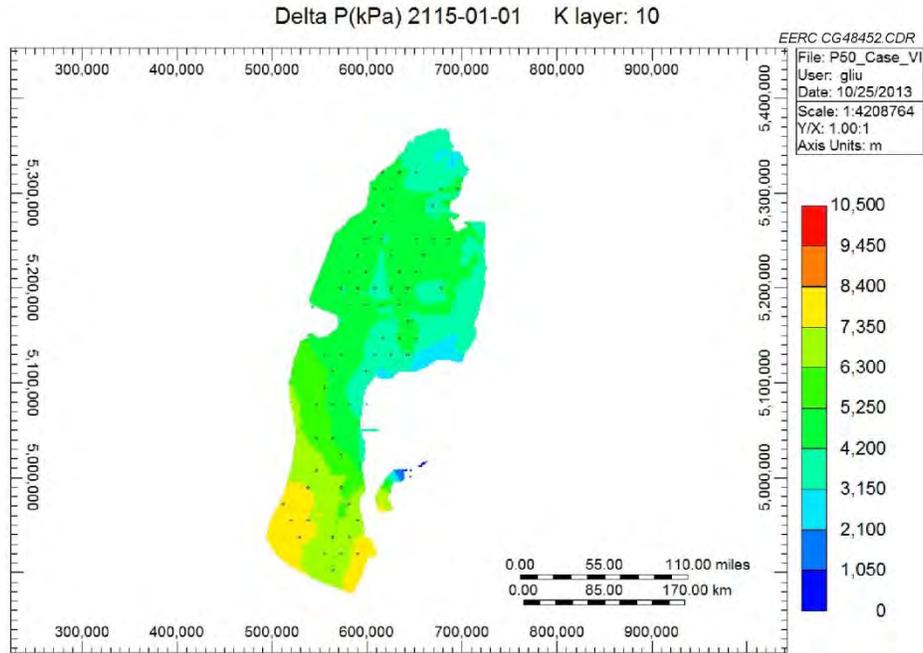


Figure B-62. Case 6: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

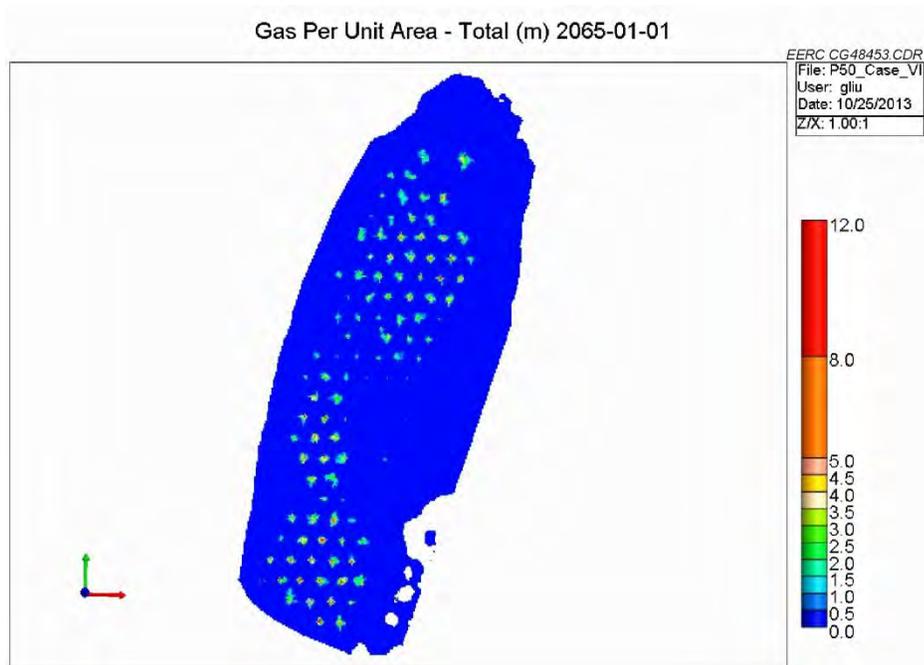


Figure B-63. Case 7: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

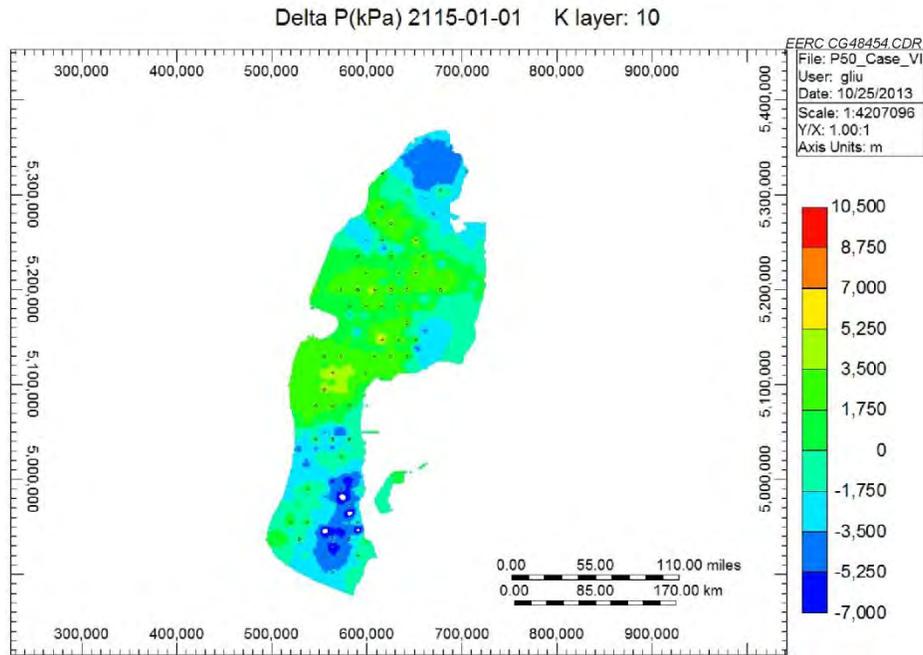


Figure B-64. Case 7: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

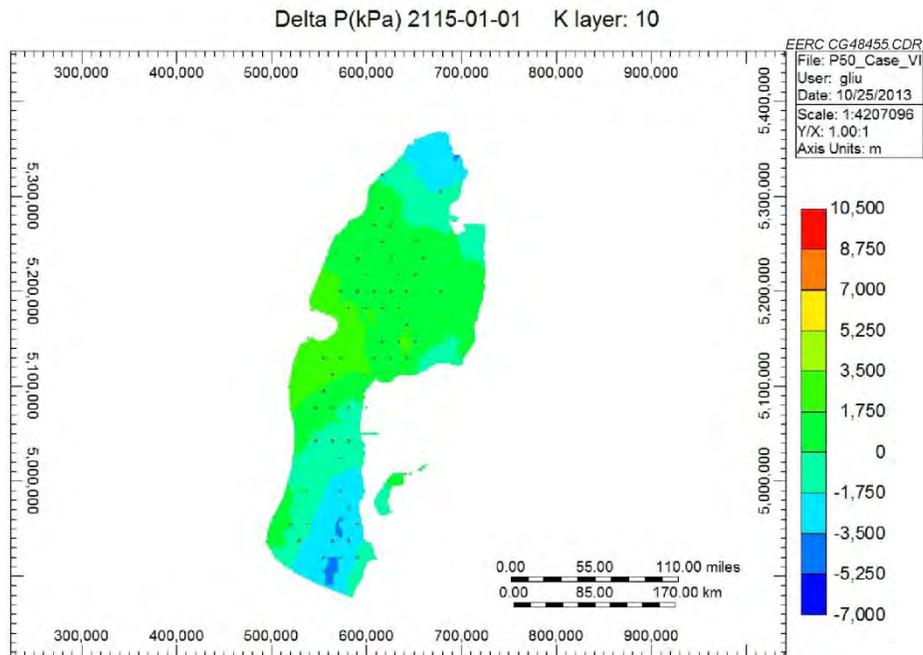


Figure B-65. Case 7: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

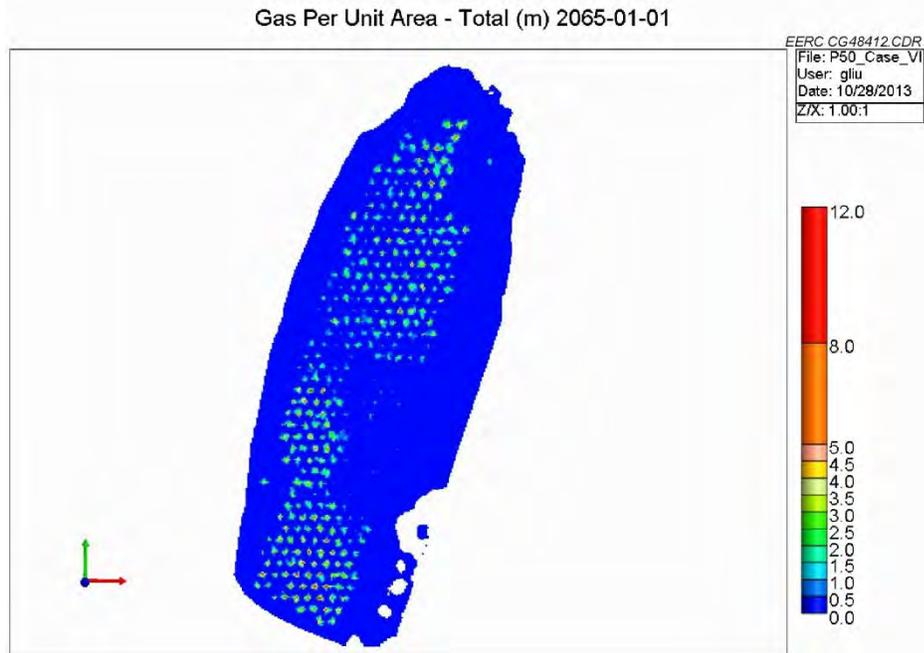


Figure B-66. Case 8: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

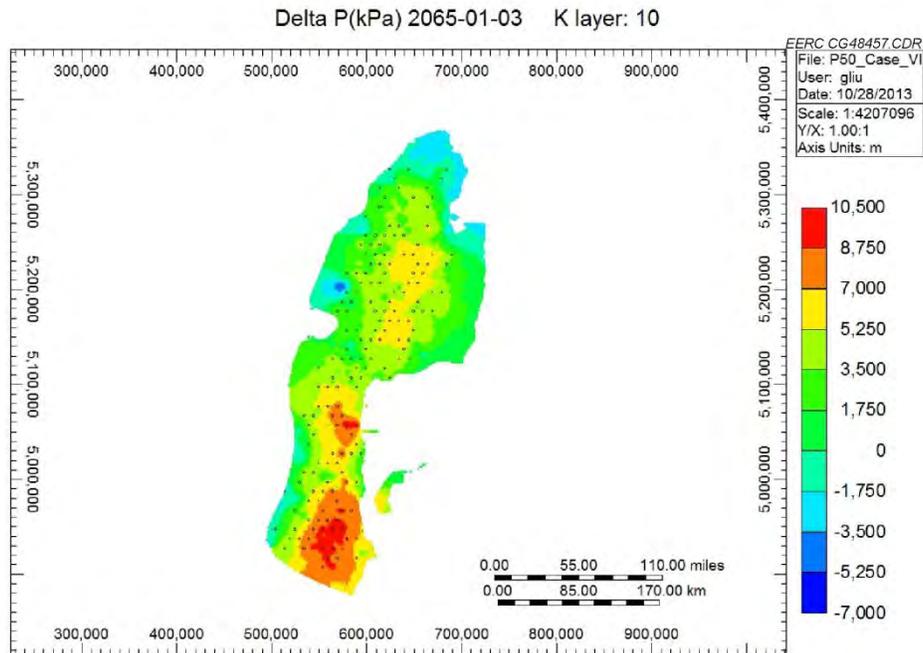


Figure B-67. Case 8: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

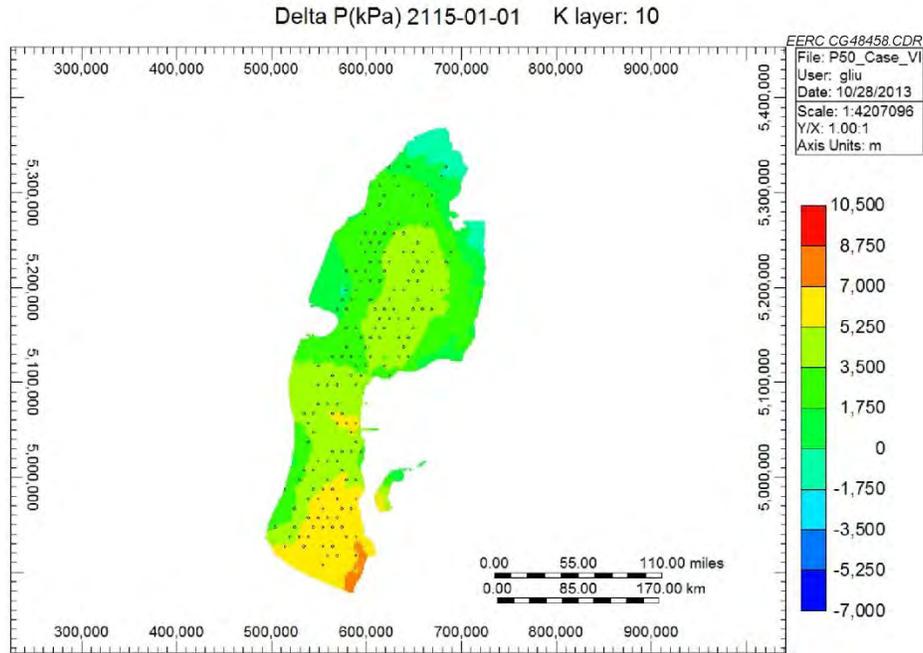


Figure B-68. Case 8: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

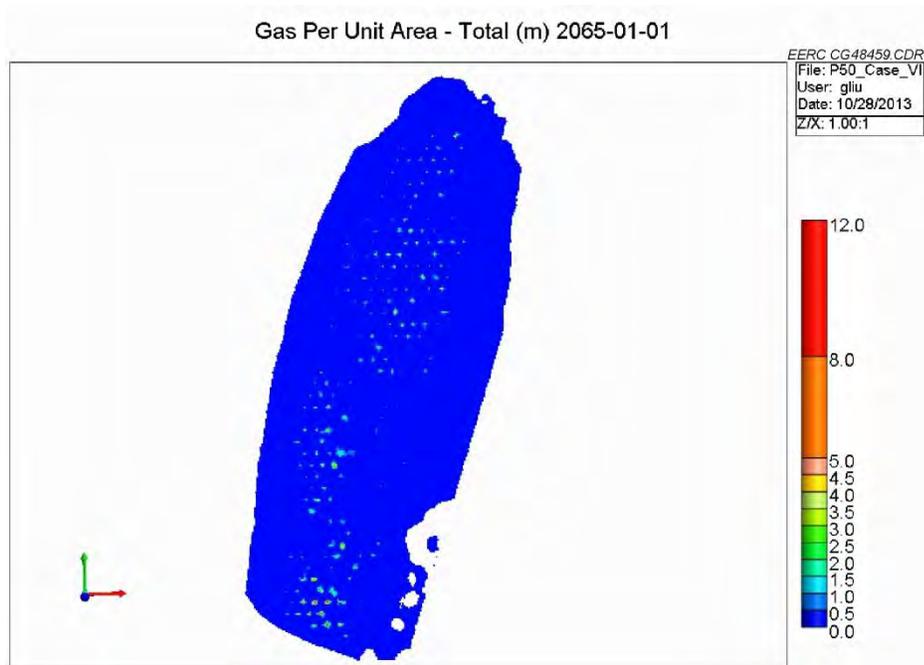


Figure B-69. Case 9: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

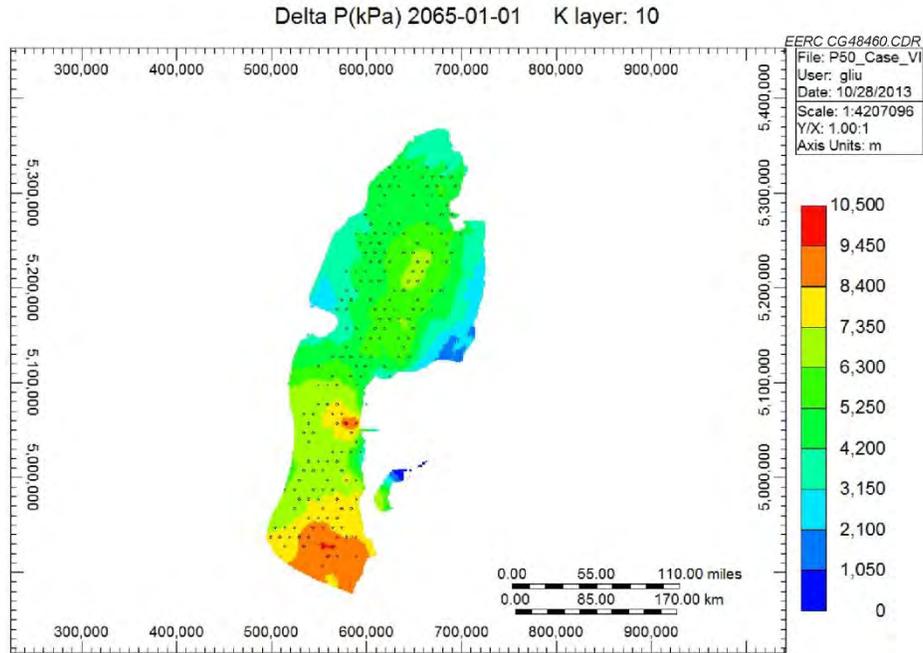


Figure B-70. Case 9: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

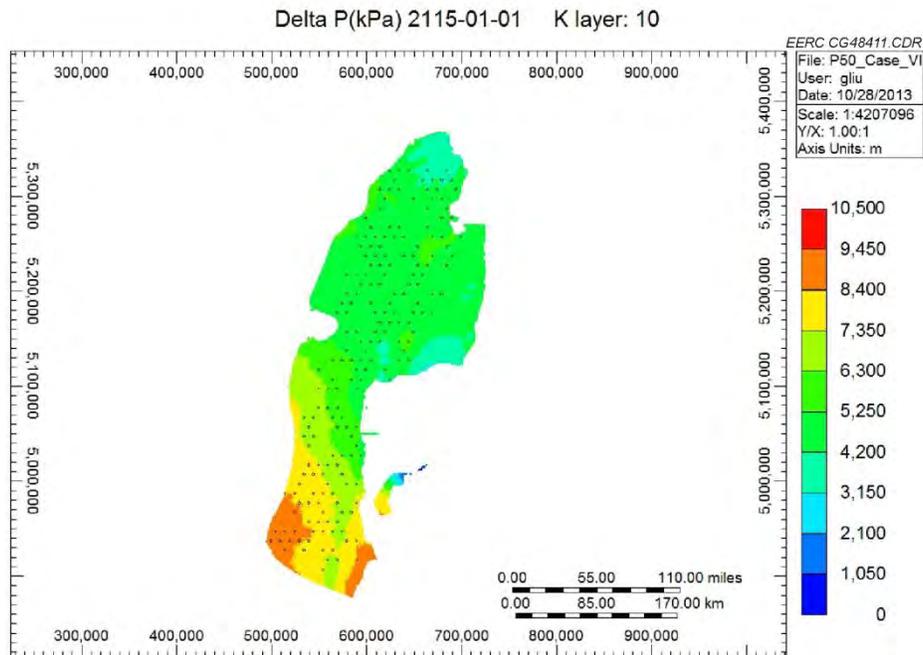


Figure B-71. Case 9: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

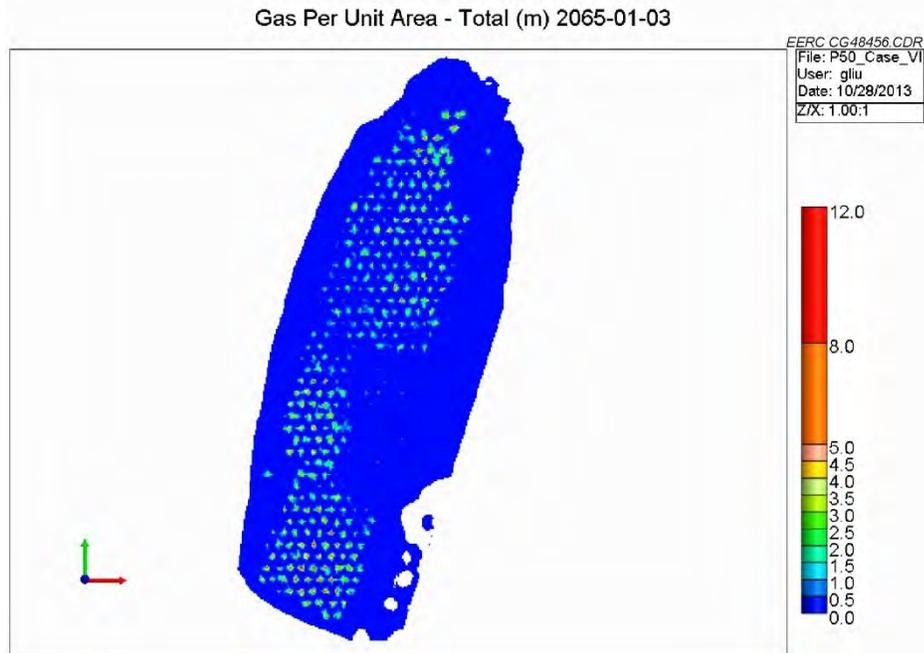


Figure B-72. Case 10: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

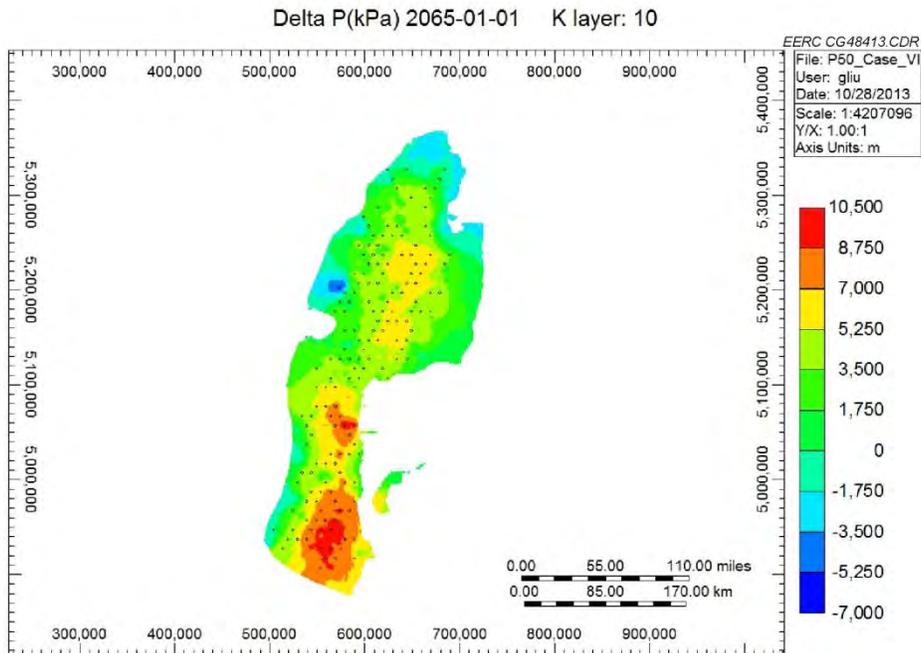


Figure B-73. Case 10: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

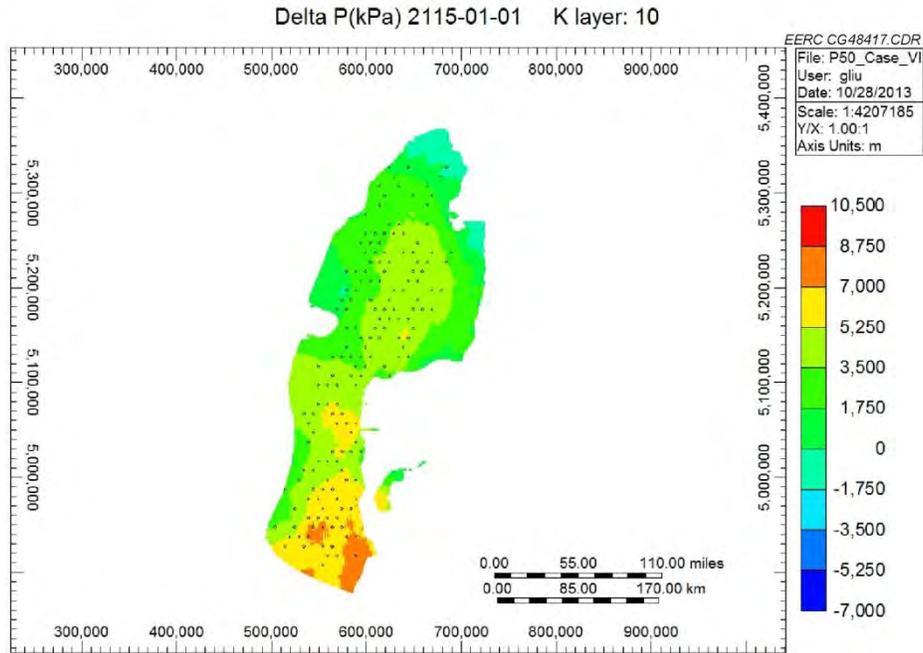


Figure B-74. Case 10: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

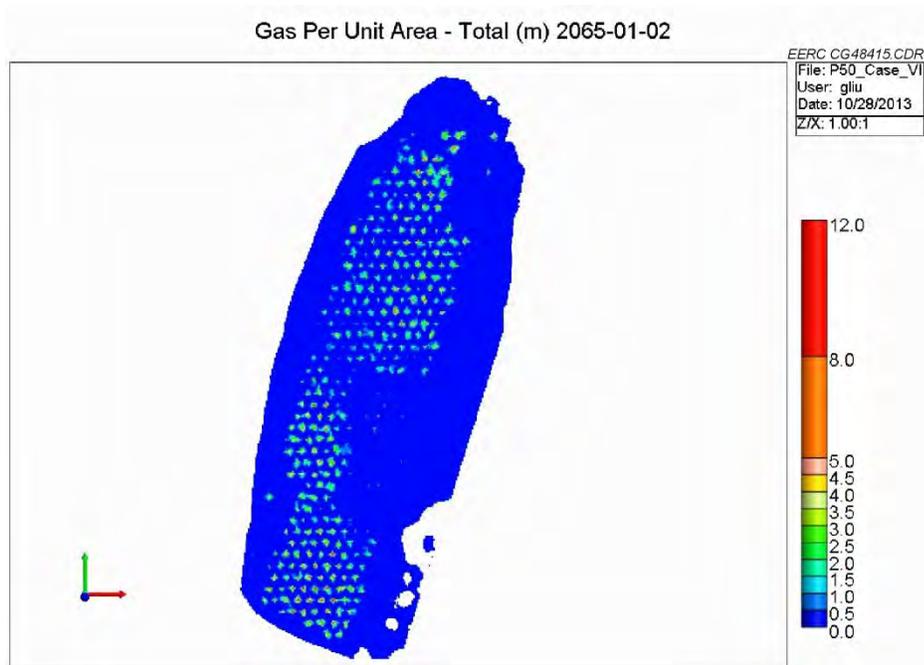


Figure B-75. Case 11: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

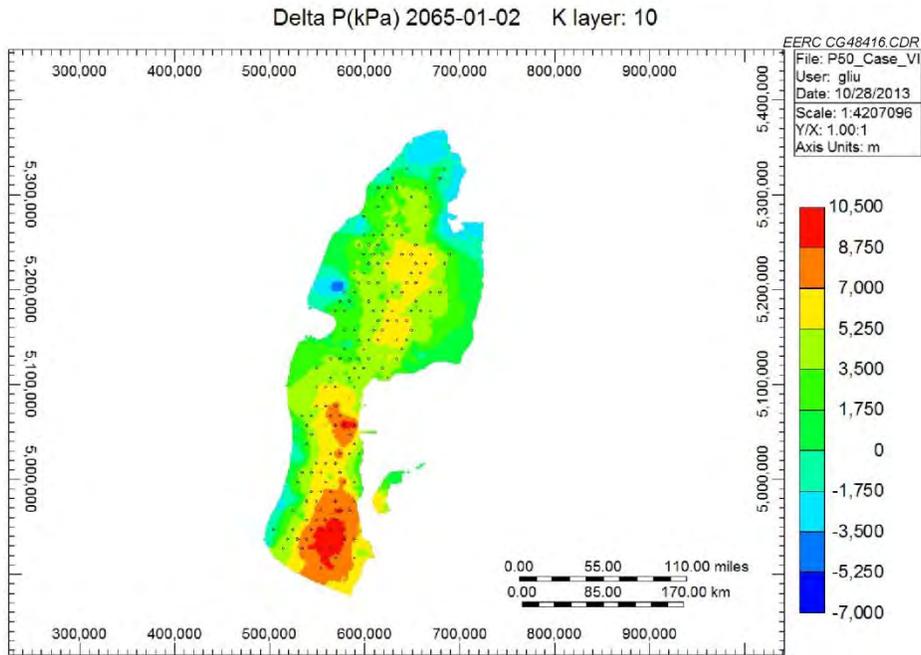


Figure B-76. Case 11: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

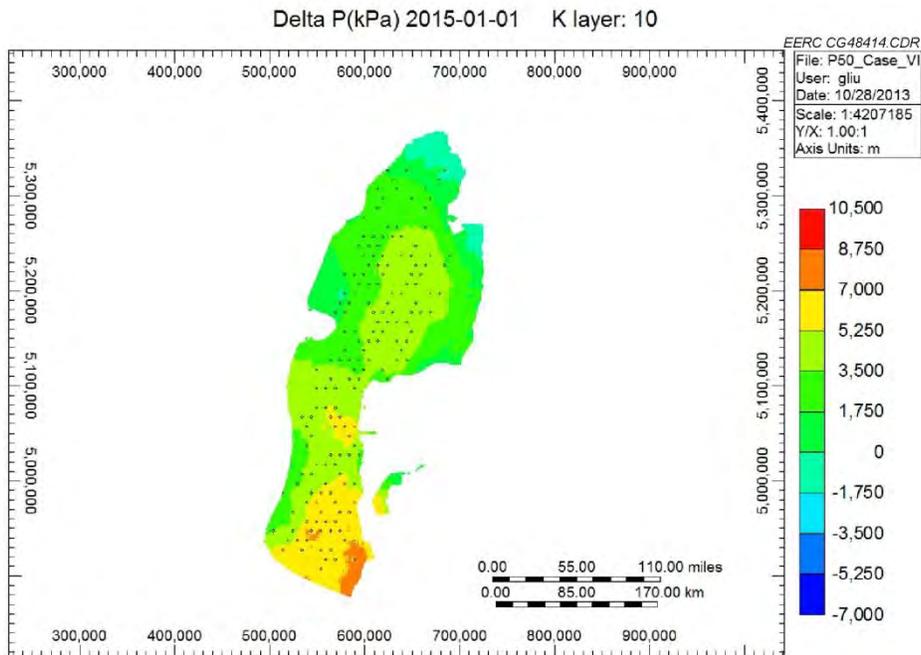


Figure B-77. Case 11: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

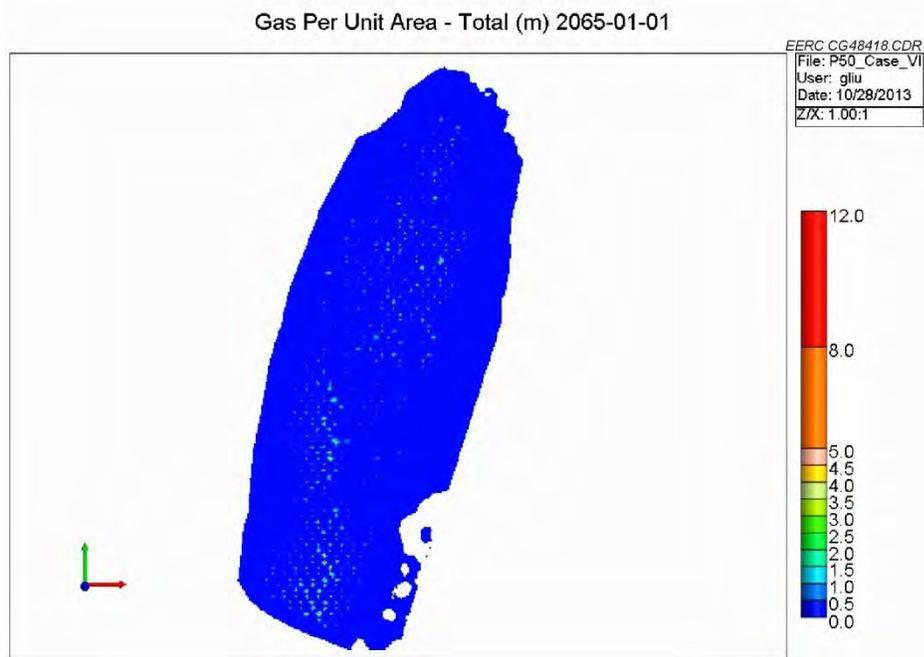


Figure B-78. Case 12: CO<sub>2</sub> footprint (total gas per unit area in meters) after 50 years of injection.

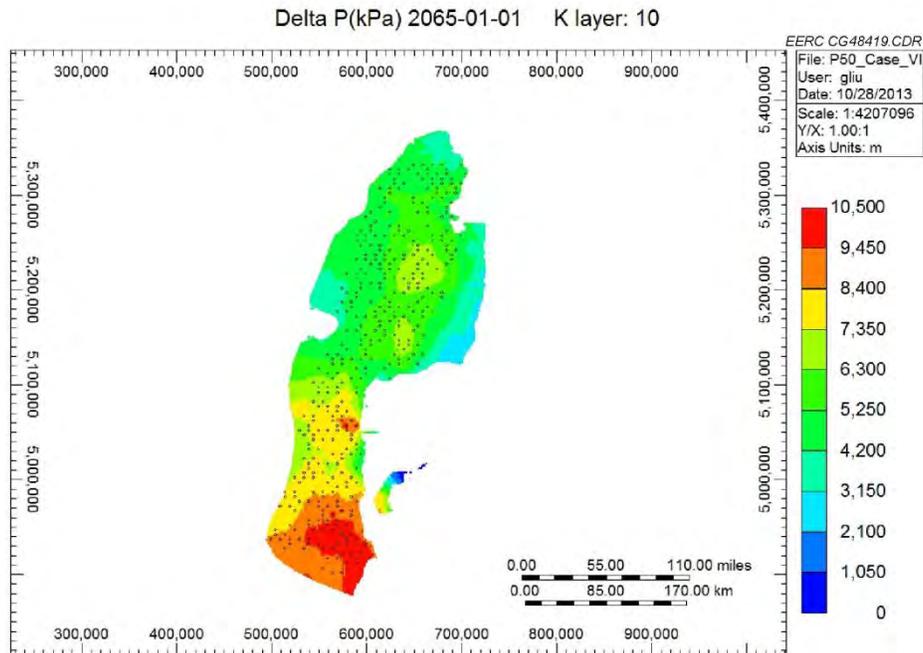


Figure B-79. Case 12: pressure difference (kPa) on the top layer of the reservoir after 50 years of injection.

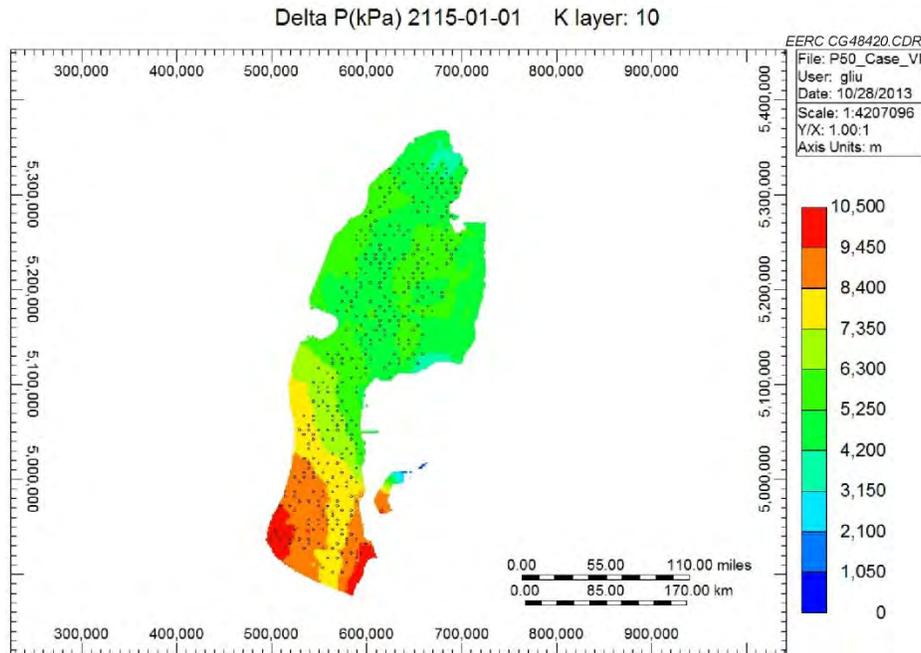


Figure B-80. Case 12: pressure difference (kPa) on the top layer of the reservoir after 50 years postinjection.

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