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# Reservoir Property Heterogeneity Influence on the $CO_2$ Injectivity , Storage Capacity, Pressure Management, and Risk Assessment, Dry Fork CarbonSAFE Project, Powder River Basin, Wyoming

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## Abstract

The Wyoming CarbonSAFE project is located at the Powder River Basin in northeast Wyoming, which aims to safely store over 50 million metric tons of $CO_2$ for a period of 30 years at three stacked reservoirs including Lakota sandstone, Hulett sandstone, and Upper Minnelusa formation. Considering these three target reservoirs show different geological heterogeneities and limited site characterization data are available to fully characterize the simulation area covered by the dynamic model, both local and global sensitivity analysis was performed to evaluate the influence of petrophysical properties, well injection control parameters and rock-fluid interaction properties on the cumulative injected gas mass.

## Introduction

The Wyoming CarbonSAFE project aims to store more than 50 million metric tons of $CO_2$ over 30 years in a stacked reservoir-caprock system (Jiao et al., 2022). Site-specific characterization data, including well logs, seismic data, core data and field tests, were integrated into a coupled fluid flow and geomechanical model to estimate the well injectivity, storage capacity, evolution of $CO_2$ plume and pressure front, surface displacement, integrity of reservoir and caprock, and fault stability(Tao et al., 2024; Yu et al., 2024). Based on the results obtained from the base case modeling, an uncertainty quantification study was conducted, which usually included both sensitivity analysis and uncertainty analysis. The sensitivity analysis was performed to assess the importance of each parameter on the performance measures of outputs, while the uncertainty analysis identifies the uncertainty in the outputs resulting from the uncertainty in the input parameters. In this paper, the result obtained from the sensitivity analysis was presented. Specifically, we evaluated the influence of petrophysical properties, well injection control parameters and rock-fluid interaction properties on the cumulative injected gas mass.

**Methods**

In the first step, we identified the uncertainty parameters that affect the outputs of interest (i.e., cumulative injected gas mass) and defined their corresponding ranges and distributions from literature or other sources. **Table 1** shows the identified uncertainty parameters, which generally can be classified into three groups. The first group consists of petrophysical parameters including porosity ($\phi$), horizontal permeability ($K_h$), vertical to horizontal permeability ratio ($K_v/K_h$) and net to gross ratio ($N/G$). The range of these parameters were defined by reducing or increasing the values used in the base case by a certain percentage. The second group includes two parameters, which control the well injection control process. The lower and upper bounds for the maximum allowed tubing head pressure (*THP*) were set as 2,000 and 2,800 psi, separately. For the maximum allowed bottom hole pressure (*BHP*), the values used in the base case were derived from the fracture gradient measured through the step rate test. However, the pressure and rate data for Lakota Sandstone and Hulett Sandstone exhibited a higher confidence than that for Upper Minnelusa Formation. Therefore, *BHP* for Upper Minnelusa Formation has a larger uncertainty range with a variation factor from 0.9 to 1.1, as compared to the range of 0.95 to 1.05 for both Lakota Sandstone and Hulett Sandstone.

**Table 1**. Identified uncertainty parameters and their corresponding ranges and distributions.

| Uncertainty Parameters | Lower Bound | Upper Bound | Distribution |
|---|---|---|---|
| Porosity, $\phi$ | × 0.75 | × 1.25 | Uniform |
| Horizontal Permeability, $K_h$ | × 0.75 | × 1.25 | Uniform |
| Vertical to Horizontal Permeability Ratio, $K_v/K_h$ | 0.01 | 0.20 | Uniform |
| Net to Gross Ratio, $N/G$ | × 0.8 | × 1.2 | Uniform |
| Maximum Allowed Bottom Hole Pressure, *BHP* | × 0.95 (Lakota, Hulett)<br>× 0.9 (Minnelusa) | × 1.05 (Lakota, Hulett)<br>× 1.1 (Minnelusa) | Uniform |
| Maximum Allowed Tubing Head Pressure, *THP* | 2,000 psi | 2,800 psi | Uniform |
| Maximum Gas Relative Permeability, $k_{rg,max}$ | 0.098191 (Lakota)<br>0.257779 (Hulett)<br>0.182149 (Minnelusa) | 0.117019 (Lakota)<br>0.482691 (Hulett)<br>0.340928 (Minnelusa) | Uniform |
| Critical Water Saturation, $S_{wc}$ | 0.541166 (Lakota)<br>0.469720 (Hulett)<br>0.406033 (Minnelusa) | 0.580502 (Lakota)<br>0.579942 (Hulett)<br>0.416358 (Minnelusa) | Uniform |
| Water Relative Permeability Exponent, $\lambda_w$ | 4.3 (Lakota)<br>2.7 (Hulett)<br>3.75 (Minnelusa) | 4.8 (Lakota)<br>4.0 (Hulett)<br>4.0 (Minnelusa) | Uniform |
| Gas Relative Permeability Exponent, $\lambda_{CO2}$ | 1.05 (Lakota)<br>1.1 (Hulett)<br>1.25 (Minnelusa) | 1.7 (Lakota)<br>1.45 (Hulett)<br>3.4 (Minnelusa) | Uniform |

Lastly, the influence of rock-fluid interaction properties, represented by the relative permeability curve, was investigated. Specifically, the relative permeability for water ($k_w$) and gas ($k_{rg}$) were characterized by the modified Brooks and Corey model:

$$k_{rw} = k_{rw,max}\left(\frac{S_w - S_{wc}}{1 - S_{wc} - S_{gc}}\right)^{\lambda_w},$$

$$k_{rg} = k_{rg,max}\left(\frac{S_g - S_{gc}}{1 - S_{wc} - S_{gc}}\right)^{\lambda_{CO_2}},$$

where $k_{rw,max}$ is the maximum water relative permeability (here is 1), $k_{rg,max}$ is the maximum gas relative permeability, $S_{wc}$ is the critical water saturation, $S_{gc}$ is the critical gas saturation (here is 0), $\lambda w$ and $\lambda_{CO2}$ are the relative permeability exponent for water and gas, respectively. The range for all four unknown parameters, including $k_{rg,max}$, $S_{wc}$, $\lambda_w$, and $\lambda_{CO2}$, were derived from the core flooding experiments. We also assumed that each parameter was uniformly distributed and independent of each other.

To reduce the computational cost, a local sensitivity analysis method, specifically One-at-A-Time (OAT) technique, was performed to select the parameters of great significance, which were evaluated further through a global sensitivity analysis method, i.e. Sobol's method, but with a reduced number of uncertainty parameters. Generally, the OAT method evaluates the influence of input parameters on the output performance measures by changing only one parameter at a time but keeping the other parameters fixed. In this way, it can efficiently find these significant uncertainty parameters by just exploring a small fraction of the parameter space without considering the interaction between parameters.

Compared to OAT, Sobol's method is a variance-based global sensitivity analysis method, which quantifies how much of the uncertainty in the model output each uncertainty parameter is responsible for. In a single run, all the uncertainty parameters are changed simultaneously, which is realized through the Latin Hypercube Sampling (LHS) approach. Sobol's method generates the case matrix by defining two base groups and iteratively switching one parameter at a time between them. More generally, for a Sobol sensitivity analysis involving $d$ uncertainty parameters and assuming there are $N$ examples in each group, the total number of parameter samples generated for simulation run is $N(d + 2)$. Then, the base model was updated based on the generated parameter sample sets and reservoir simulation was conducted for each updated model. The results obtained were used to calculate the Sobol index, which quantitatively characterized how much of the variance in the model output each uncertainty parameter was responsible for.

## Results

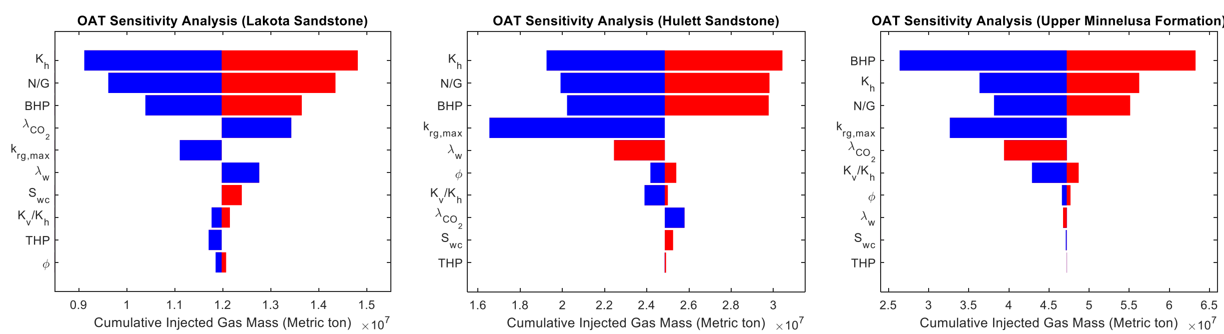


**Figure 1**. Tornado diagrams show the influence of each uncertainty parameter on the cumulative injected gas mass based on the OAT sensitivity analysis for (left) Lakota Sandstone, (middle) Hulett and (right) Upper Minnelusa Formation.

The tornado diagrams in **Figure 1** show the potential range of cumulative injected gas mass corresponding to the variation of each uncertainty parameter for each target reservoir. The variational range was plotted against a base value obtained from the base case and was denoted with two different colors, where the red and blue colors represent the increment and reduction of the input parameter, respectively. The importance of each input parameter was characterized by its corresponding variational range of the output and was ranked in the tornado diagrams with a reduced importance from top to bottom. The top first five significant parameters identified from the tornado diagrams were selected to investigate their influence further with Sobol's method. Specifically, the selected uncertainty parameters for each target reservoir are (listed with a reduced importance): $K_h$, $N/G$, $BHP$, $\lambda_{CO2}$ and $k_{rg,max}$ (Lakota Sandstone); $K_h$, $N/G$, $BHP$, $k_{rg,max}$ and $\lambda_w$ (Hulett Sandstone); $BHP$, $K_h$, $N/G$, $k_{rg,max}$ and $\lambda_{CO2}$ (Upper Minnelusa Formation).

**Figure 2** shows the calculated first-order Sobol index and total-order Sobel index for each target reservoir, which quantifies the influence of each considered uncertainty parameter on the cumulative injected gas mass at each reservoir. First-order Sobol index measures the direct influence each parameter has on the variance of the model, while total-order Sobol index considers both the effect of only changing uncertainty parameter $X_i$ and the interaction between $X_i$ and any number of other uncertainty parameters. For Lakota Sandstone, the ranking of uncertainty parameters based on their influence on the final amount of injected $CO_2$ remains similar, regardless of whether the first-order or total-order Sobol index is used as the metric. It indicates that the interaction between different uncertainty parameters does not play a significant role for the final amount of injected $CO_2$. The first three most important uncertainty parameters for Lakota Sandstone are $K_h$, $BHP$ and $N/G$. In comparison, the ordering of uncertainty parameters for Hulett Sandstone is $BHP > N/G > k_{rg,max} > K_h > \lambda_w$ in terms of the first-order Sobol index and $BHP > k_{rg,max} > K_h > N/G > \lambda_w$ based on the total-order Sobol index. Clearly, the different ranking orders indicate that some interactions come into play, especially those involving $k_{rg,max}$ and $K_h$. For Upper Minnelusa Formation, the dominant uncertainty parameter is $BHP$ no matter which metric is used. In particular, it takes up over 50% in terms of the first-order Sobol index. However, it should be noted that as the reliability of injection tests conducted at the Upper Minnelusa Formation was not as good as those for Lakota Sandstone and Hulett Sandstone, the variational range of $BHP$ for Upper Minnelusa Formation is two times larger than other two reservoirs, ranging from 90% to 110%.

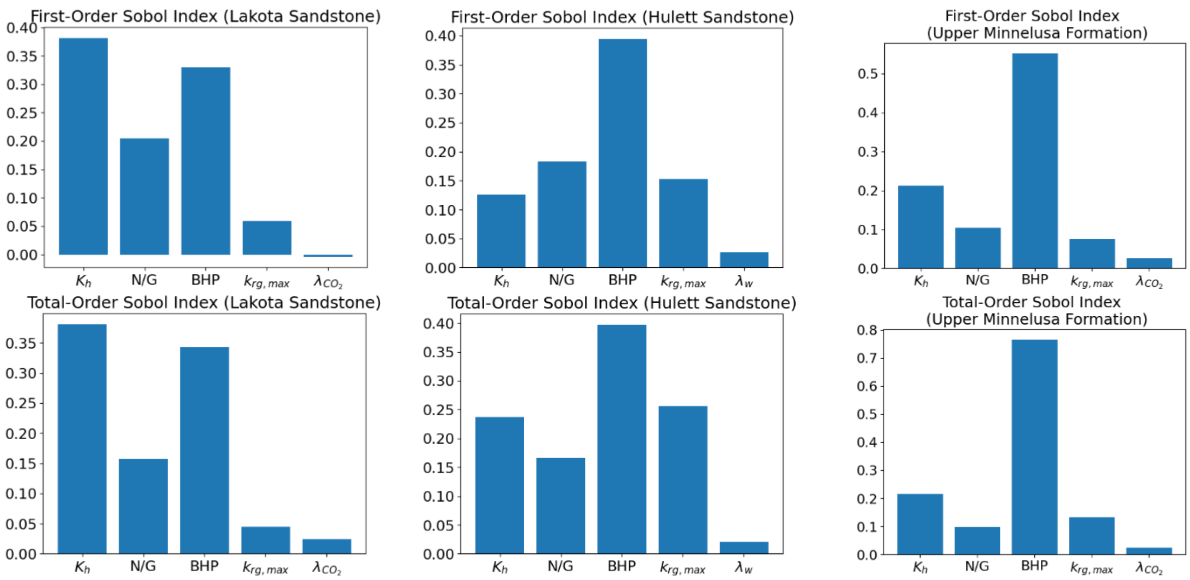


**Figure 2**. Calculated first-order Sobol index and total-order Sobol index for each target reservoir, which quantifies the influence of each uncertainty parameter on the cumulative injected gas mass.

## Conclusions

This study evaluated the impact of petrophysical properties, well injection control parameters and rock-fluid interaction properties on the cumulative injected gas mass. Sensitivity analyses, including One-at-a-Time and Sobol's methods, highlighted the significance of parameters such as permeability, net-to-gross ratio, bottom hole pressure, and relative permeability characteristics. Key findings indicate that parameter importance and interactions vary significantly across the three target reservoirs—Lakota Sandstone, Hulett Sandstone, and Upper Minnelusa Formation. For example, bottom hole pressure emerged as a dominant factor in the Upper Minnelusa Formation, reflecting its broader uncertainty range due to limited site-specific data. These insights underscore the necessity for comprehensive site characterization and uncertainty quantification to optimize injection strategies and manage risks effectively. The results can inform decision-making processes for large-scale $CO_2$ sequestration projects by highlighting critical parameters requiring rigorous control or monitoring. Future work will focus on enhancing the reliability of field tests and exploring advanced modeling techniques to further refine predictions for reservoir behavior under $CO_2$ injection scenarios.

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