International Journal of Greenhouse Gas Control 22 (2014) 123–138

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

journal homepage: www.elsevier.com/locate/ijggc

Model complexity in carbon sequestration: A design of experiment and response surface uncertainty analysis

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ARTICLE INFO

Article history:
Received 12 July 2013
Received in revised form
10 December 2013
Accepted 13 December 2013
Available online 23 January 2014

Keywords:
Carbon sequestration
Geologic reservoir modeling
Uncertainty analysis
Design of experiment
Response surface
Proxy model

ABSTRACT

Geologic carbon sequestration (GCS) is considered a promising means of reducing atmospheric carbon dioxide (CO_2). In Wyoming, GCS is proposed for the Nugget Sandstone in Moxa Arch, a deep, regional-scale saline aquifer with a large CO_2 storage potential. For a proposed storage site, this study builds a suite of increasingly complex conceptual geologic model families, using subsets of the site characterization data: a homogeneous model family (FAM1), a stationary petrophysical model family (FAM2), a stationary facies model family with sub-facies petrophysical variability (FAM3), and a non-stationary facies model family (with sub-facies variability) conditioned to soft data (FAM4). These families, representing alternative conceptual site models built with increasing data, were simulated with the same CO_2 injection test (50 years at 1/10 Mt (1.0×108 kg) per year), followed by 2950 years of monitoring. Using the design of experiment, an efficient sensitivity analysis (SA) is conducted for all families, systematically varying uncertain aquifer parameters, while assuming identical well configuration, injection rate, bottomhole pressure constraint, and boundary conditions, i.e., the model is considered a part of a larger, semi-infinite system, where both the injected CO_2 and the formation brine can flow out. The SA results are compared among the families to identify parameters that have 1st order impact on predicting CO_2 storage ratio (SR) at two different time scales, i.e., end of injection and end of monitoring. This comparison indicates that, for this deep aquifer with a gentle incline, geologic modeling factors do not significantly influence the short-term prediction of the CO_2 storage ratio. However, these factors become more important over the monitoring time, but only for those families where such factors are accounted for (in other words, their long-term importance cannot be revealed by the relatively simple conceptual models). Based on the SA results, a response surface analysis is conducted to generate prediction envelopes of the storage ratio, which are also compared among the families, and at both time scales. Results suggest a large uncertainty in the predicted storage ratio, given the uncertainties in model parameters and modeling choices: the SR varies from 5–60% (end of injection) to 18–100% (end of monitoring), although its variation among the model families due to different modeling choices is relatively minor. Moreover, long-term leakage risk is considered small at the proposed site. This is because, in the lowest-SR scenarios, all model families predict gravity-stable supercritical CO_2 migrating toward the bottom of the aquifer. In the highest-SR scenarios, supercritical CO_2 footprints are relatively insignificant by the end of monitoring.

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1. Introduction

Geological carbon sequestration (GCS) is considered to be a promising option for mitigating global climate change (IPCC, 2013). Wyoming produces approximately 40% of the coal in the United States. In 2000, coal-fired power plants in the state emitted a total of 51 million tons (Mt) of CO_2 into the atmosphere (Stauffer et al., 2009a). By 2009, the emission rate had risen to 54.4 Mt/year and it is further projected to increase with new energy demand (Deng et al., 2012; Easley et al., 2013). To achieve climate mitigation, power plants such as these are the chief targets for conversion to allow the capture of CO_2 and subsequent sequestration underground. Given the magnitude of the emission rate, CO_2 needs to be sequestered at industrial scales for which deep saline aquifers with large storage capacity are needed (Bachu, 2000). The Moxa Arch anticline in western Wyoming is a deeply buried subsurface structure and a proposed GCS site (Fig. 1). Multiple deep saline aquifers with large storage capacities have been identified that lie adjacent to several coal-fired power plants including the 2.1 GW Jim Bridger Power Plant (Li et al., 2011). The anticline consists of geologic formations ranging from Precambrian crystalline rocks to Holocene alluvial sands and gravels. It hosts natural gas in the Frontier Sandstone

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1750-5836/$ – see front matter. Published by Elsevier Ltd.
http://dx.doi.org/10.1016/j.ijggc.2013.12.007

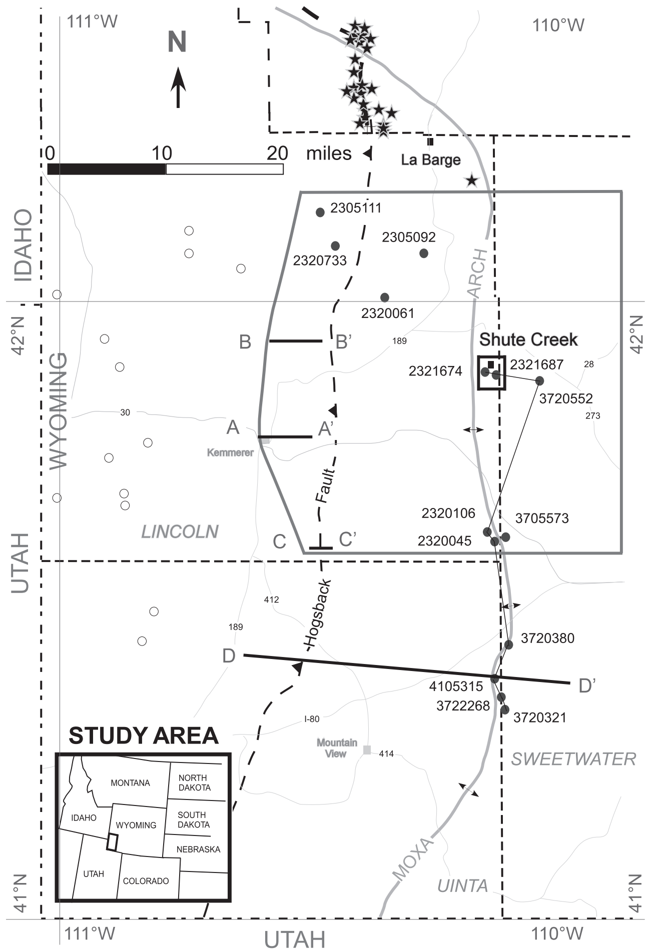

Fig. 1. A map of the study site with the location of a regional model indicated by the larger outline. Wells that penetrate to the depth of the Nugget Sandstone are shown: solid symbols denote wells inside Moxa Arch (circles with API numbers were used in well log correlation to create the regional model (Li et al., 2011); stars denote wells from natural gas fields northwest of La Barge where Nugget facies and petrophysical properties were examined); empty circles are those that lie outside the Arch where Nugget facies and petrophysical properties were examined. AA′, BB′, CC′, and DD′ are cross sections used in creating the regional model, from which a section model centered at Shute Creek (small box) is extracted for CO_2 simulation. Also shown is a thin line connecting a set of wells, which extends from Shute Creek toward the southern Moxa Arch. Along this line, a well log correlation profile is presented in Fig. 2.

(Harstad et al., 1996) and natural CO_2 in the Madison Limestone (Huang et al., 2011), attesting to the sealing capacity of multiple, low-permeability caprock formations. At the Shute Creek gas plant (Fig. 1), acid gas disposal into the Madison Limestone has been ongoing since 2005 at a rate of 60 MMscf/day (1.7 MM m^3/day), and is one of the world's largest acid gas reinjection projects (Huang et al., 2011). In the region surrounding the gas plant, few wells perforate these deep formations, reducing leakage risk via wellbores. Interpretation of three-dimensional seismic data acquired northwest of Shute Creek has not identified large faults, suggesting structure continuity. With infrastructure including deep injection wells and CO_2 pipelines, the gas plant is considered a candidate site for CO_2 injection.

In evaluating a GCS site, reservoir flow simulation is commonly performed based on a geologic site model which characterizes subsurface structure, facies, and other heterogeneities. To resolve detailed heterogeneity, increasing subsurface characterization effort is required, and the greater the detail, the higher the cost. GCS, in particular, CO_2 storage in deep saline aquifers, is frequently considered a "cost center". Moreover, for the type, amount, and accessibility of data at a given site, different geologic models can be built, ranging from the simple to complex. For example, petrophysical properties can be alternatively modeled assuming homogeneity (Birkholzer and Zhou, 2009) or heterogeneity (Deng et al., 2012), the latter requiring advanced modeling techniques supported by additional data. Although such data can be obtained from drilling and logging the aquifer, or from high-resolution geophysical surveys, extensive data acquisition is not realistic at large scales where industrial CO_2 storage is concerned. Besides the cost constraint, leakage from wellbores must be minimized, limiting the number of boreholes that can be drilled. A critical issue in GCS is therefore to determine the right types of data to collect, and, based on these data, the right type of geologic model to construct, leading to a cost-effective strategy in data collection. Such models, as input to flow simulation, will ideally lead to adequate, or sufficiently accurate, predictions of the desired outcomes, while models are not overly detailed and are therefore cost-prohibitive to construct. However, the identification of an optimal model is challenging due to the fact that in GCS modeling, a variety of uncertainty factors exist, including geologic factors influencing reservoir porosity and permeability, engineering factors influencing gas trapping and migration, and environmental factors influencing CO_2 fluid properties. Although the uncertainty factors that exert the most significant impact on CO_2 predictions are of the most interest—these are the ones that need to be better characterized, reducing their uncertainties and therefore uncertainty in predictions, as model complexity (level of detail) increases, more geologic uncertainty factors can come into play (Friedmann et al., 2003; Milliken et al., 2007).

Toward the overall objective of developing cost-effective models, this study aims to understand model complexity in GCS and the associated data needs, including both static and dynamic data. For the storage formation, the Nugget Sandstone in Moxa Arch has been chosen, which is a deep (13,000–17,000 ft depth), regional-scale saline aquifer with a large storage potential, due to its large areal extent, significant thickness (on average, 700 ft (213 m) thick), and relatively high porosity. It is separated from the overlying gas-bearing Frontier Sandstone by multiple, low-permeability formations, while Frontier itself is capped by low-permeability cap rocks. Detailed discussion of the Nugget Sandstone's geological and depositional settings can be found in Li et al. (2011). Along a profile connecting several wells (Fig. 1), well log correlation suggests the continuity of the Nugget Sandstone at regional scales (Fig. 2), which is confirmed by seismic line shots in southern Moxa Arch (David et al., 1975; Royse et al., 1975). At the Shute Creek gas plant, Nugget Sandstone overlies the Madison Limestone, where acid gas injection is ongoing. Here, few wells perforate to the depth of the Nugget (Fig. 1), minimizing leakage risk. The gas plant, where existing wells can be fitted for injecting CO_2, is a proposed GCS site. However, due to limited well data at the plant, much uncertainty exists in describing Nugget Sandstone's porosity and permeability. On the one hand, reservoir heterogeneity is known to exist as evidenced by examining the wireline logs and computed clay volumes of formation (Fig. 2). On the other hand, large distances between wells give rise to uncertainty as to the appropriate geologic modeling method that can best capture the relevant heterogeneity. In fact, alternative modeling methods exist, whereas the effect of different methods on porosity/permeability prediction, and therefore CO_2 storage modeling, is unknown.

To understand the uncertainty in CO_2 storage modeling in the Nugget Sandstone and the impact of model complexity on CO_2 predictions, this study creates multiple families of geologic models with different techniques to determine if the list of "heavy hitters" (i.e., uncertainty factors whose variations have significant impact on a prediction outcome) will change with the modeling choice. Because CO_2 flow is often dominated by viscous force during injection and gravity force during monitoring, the list of heavy hitters

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