Application of the CO2-PENS risk analysis tool to the Rock Springs Uplift, Wyoming.

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Abstract

We describe preliminary application of the CO\textsubscript{2}-PENS performance and risk analysis tool to a planned geologic CO\textsubscript{2} sequestration demonstration project in the Rock Springs Uplift (RSU), located in south western Wyoming. We use data from the RSU to populate CO\textsubscript{2}-PENS, an evolving system-level modeling tool developed at Los Alamos National Laboratory. This tool has been designed to generate performance and risk assessment calculations for the geologic sequestration of carbon dioxide. Our approach follows Systems Analysis logic and includes estimates of uncertainty in model parameters and Monte-Carlo simulations that lead to probabilistic results. Probabilistic results provide decision makers with a range in the likelihood of different outcomes. Herein we present results from a newly implemented approach in CO\textsubscript{2}-PENS that captures site-specific spatially coherent details such as topography on the reservoir/cap-rock interface, changes in saturation and pressure during injection, and dip on overlying aquifers that may be impacted by leakage upward through wellbores and faults. We present simulations of CO\textsubscript{2} injection under different uncertainty distributions for hypothetical leaking wells and faults. Although results are preliminary and to be used only for demonstration of the approach, future results of the risk analysis will form the basis for a discussion on methods to reduce uncertainty in the risk calculations. Additionally, we present ideas on using the model to help locate monitoring equipment to detect potential leaks. By maintaining site-specific details in the CO\textsubscript{2}-PENS analysis we provide a tool that allows more logical presentations to stakeholders in the region.

Keywords: Risk Analysis; Wellbore Leakage.

1. Introduction

The State of Wyoming, in collaboration with Los Alamos National Laboratory (LANL) is undertaking an analysis of the Rock Springs Uplift as a possible location for sequestration of volumes of CO\textsubscript{2} on the order of cubic kilometres [1,2,3]. This site is of particular interest because of the collocated 2.1 GW Jim Bridger coal burning power plant and the possibility of additional power plants being developed to take advantage of the abundant coal reserves in the RSU area. The Rock Springs Uplift is a large asymmetric dome structure, 50-85 km, with two superior target sequestration reservoirs located beneath a 1500 m thick sequence of Cretaceous shale. The uppermost target reservoir, the Weber sandstone, has a thickness of over 200m with permeability and porosity ranging from 0.1-15 md and 0.03-0.1 respectively. Preliminary estimates of the storage capacity of the Weber within the boundaries of

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the RSU are on the order of 18GT supercritical CO₂ [3]. Data from oil/gas drilling around the perimeter of the uplift show that there is likely good injectivity in the Weber and that the overlying cap-rocks have contained buoyant fluids in this formation for long periods of time [3,4,5]. Although data exist to show that the Weber may provide a high quality storage reservoir for CO₂, a more quantitative approach that includes uncertainty in system behavior is required before industrial scale operations could be justified. In the following section we describe CO₂-PENS, a tool that can be used to organize site data into a system level model for quantitatively addressing such uncertainty.

Several groups around the world are currently attempting to build systems level simulators that can address the role of uncertainty in predictions of performance and risk [6,7,8], and each group is taking somewhat different approaches. Approaches range from simple analytical methods linked in spreadsheets [7] to more complex methods utilizing fully non-linear three dimensional calculations. However, researchers are finding the computational burden of the more complex simulations prohibitive and turning the focus to hybrid approaches that use reduced complexity algorithms to capture the bulk of first order processes while allowing rapid solution of the entire system [e.g. 9]. Although the ideas behind these types of calculations are well developed in other fields (e.g. nuclear waste storage, nuclear power plant design), they have not yet reached maturity in the CO₂ sequestration arena. The ultimate usefulness of the system level modeling approach is that probabilistic results provide decision makers with a range in the likelihood of different outcomes, and allow resources to be focused on reducing uncertainty where it is most beneficial to do so.

Developed at Los Alamos National Laboratory (LANL), CO₂-PENS (Predicting Engineered Natural Systems) is a system model for performance assessment and risk analysis of geologic sequestration of CO₂ (6,10,11,12). CO₂-PENS is build from within the GoldSim modeling environment, although many of the more complex algorithms are coded separately as dynamically linked libraries (DLLs). Our current research builds on work that integrates science-based processes level models into a larger system model through both model abstraction and reduction of complexity. Previously, we have demonstrated the usefulness of CO₂-PENS in comparing the number of wells and associated costs for two injection scenarios [10], and in estimating reservoir capacity as part of a larger oil shale system coupling pipeline optimization with possible sequestration reservoir locations [12]. The model generates probabilistic simulations of CO₂ capture, transport, injection, and migration into geologic reservoirs, and subsequent leakage toward overlying aquifers and the surface [11]. Leakage in the current version of CO₂-PENS occurs through wellbores and/or faults. CO₂-PENS uses statistical distributions to define input parameters and a Latin Hypercube Monte Carlo technique to assess the impact of uncertainty in input parameters on model outputs.

Herein we present results from a newly implemented approach in CO₂-PENS that captures site-specific spatially coherent details such as topography on the reservoir/cap-rock interface and evolution of saturation and pressure during injection that may impact leakage upward through wellbores and faults. The model can also accept input for overlying aquifers that have topographic relief and non-hydrostatic pressures and variable temperatures. We use results from a fully couple 3-D reservoir simulator as input to CO₂-PENS to drive estimates of CO₂ leakage through wells and faults. Although results are preliminary and to be used only for demonstration of the approach, future results of the risk analysis will form the basis for a discussion on methods to reduce uncertainty in the risk calculations. Additionally, the new spatially coherent allows locations to be chosen for monitoring equipment to detect potential leaks. Finally, by maintaining site-specific details in the risk assessment for the RSU we provide a tool that will allow more logical presentations to stakeholders in the region.

2. Geological structural model and generation of the 3-D computational mesh

A regional 3-D geological model of the RSU was built using the software EarthVison, a 3-D geospatial modeling package. No faults are included in this structural model. More details on the methodology can be found in [13]. Following the logic and methodology outlined in [1], a computational hydrostratigraphic mesh was created from the 16 km by 16 km geological structural model described above. The current mesh has been refined (from the
image shown in Figure 1) in the vertical direction in the rock units of interest to allow inclusion of geostatistical permeability and porosity distributions. Figure 1 shows (A) the complete geologic model and (B) a zoom into the computational mesh with some of the units of interest called out. Figure 2 shows a permeability field (log$_{10}$ m$^2$) sliced on a vertical cross section through numerical mesh (B-B’ on Figure 3).

3. Full 3-D injection simulations

Simulations of CO$_2$ injection are run on the Los Alamos National Laboratory Finite Element Heat and Mass Transfer (FEHM) multiphase porous flow simulator. FEHM is capable of simulating many multiphase porous flow problems, including isotopic fractionation in the vadose zone, methane hydrate dissolution and transport, geothermal energy analysis, and simulations of CO$_2$ injection into saline aquifers, see references in [1].

The 3-D simulation that forms the basis for the CO$_2$-PENS leakage calculations in this paper is quite similar to those described in [1]. The most dramatic modification to these simulations is the inclusion of heterogeneity in the permeability and porosity structure in the Weber, Madison, Phosphoria, and Chugwater formations. This was done to give some insight into more realistic plume behavior and to allow more accurate estimates of total capacity. Although we are currently working on a publication that addresses uncertainty due to variability in permeability and porosity structure in the 3-D simulations, we have chosen to use only one of these realizations to drive the leakage simulations to highlight the uncertainty coming from the CO$_2$-PENS leakage calculations. Because the more realistic permeability distributions result in lower effective bulk permeability, the simulation used in this paper requires 16 injectors and lead to approximately 500 MT of injected CO$_2$ over 50 years. Figure 3 shows the simulated supercritical CO$_2$ saturation at the top of the Weber after 50 years of injection. After 50 years the injection was stopped and the simulation was run to 200 years. Another significant change in model formulation relative to [1] is the inclusion of four producing water wells at the perimeter of the CO$_2$ plume to maintain pressure below hydrofracture ratios and explore the ability of the system to produce brine as a useable by-product of the sequestration activity [2].

4. CO$_2$-PENS Model Details

During the past year, the CO$_2$-PENS model has been modified to include a spatial data structure that allows the user to generate performance and risk profiles based on actual physical locations. While we capture some spatial details, the model is not meant to be a full 3-D simulator. As a compromise, we have built a template within GoldSim that requires the user to segment the study area into 100x100 discrete bins. These bins form the footprint of the leakage scenarios that can then be run. In the example presented here, our 16km x 16km 3-D simulation is mapped into ten thousand bins, each of which has dimensions of 160m x 160m. To account for vertical migration, the CO$_2$-PENS model is given five horizontal slices, representing the injection reservoir, three overlying aquifers or porous resource layers (e.g. oil/gas), and finally the near surface atmosphere. The overlying aquifers and land surface are discretized at a coarser resolution in the data lookup tables, however all layers retain the 100x100 bin resolution for calculation of leakage. For the model presented, the overlying aquifers were created using an algorithm that maps their vertical position as a constant relative to the top of the Weber from the 3-D reservoir model. The aquifers are given constant
permeability (7e-13 m², 9e-13 m², and 2e-12 m²) and thickness, (80 m 30 m 50 m), and lie 300 m, 400 m, and 600 m above the Weber top respectively for aquifers 1, 2, and 3. In CO₂-PENS, the user can choose between a complex reservoir in which 3-D model output is loaded into a lookup table to drive the leakage calculations, or a simple reservoir option that uses a response surface generated by prior runs of 100s of cases of CO₂ injection. Limitations on the simple option include level topography on the reservoir and an assumption of brine pumping at a fixed radius from each injector. The complex reservoir option allows the user to generate a CO₂ plume using whatever scenario one wishes to explore. Likewise, the overlying aquifers can be simply assigned as flat homogeneous formations, or given properties that vary with space.

Spatial data requires visualization for ease in understanding and debugging, and CO₂-PENS is now equipped with a GNU plot interface that automatically produces plots such as Figure 4, showing the CO₂-PENS output at 50 yrs for our example problem, echoing the 3-D saturation profile seen in Figure 3. This figure is crucial because one of the primary assumptions in the complex case is that pressures and saturations at the top of the CO₂ storage reservoir drive flow into leakage pathways. PENS outputs similar figures for reservoir pressure and temperature to allow the user to see what parameters are driving leakage and to ensure that the 3-D system has been correctly mapped into the PENS model structure.

a. Leakage pathways – Wells

Leakage pathways at the actual site upon which the geologic framework model is built are poorly understood, and for the sake of demonstration we now embark on a hypothetical example where each leakage pathway currently developed in CO₂-PENS is given a defined spatial location for ease in explaining the nature of the input data and showing how results are generated.

The first leakage pathway is through existing wells. These wells may be ‘know wells’, that is to say their number and locations are well known, or ‘unknown wells’, where locations and numbers of wells drilled in the past are poorly defined. Unknown wells are of particular importance in locations such as West Texas, where historic drilling resulted in some portion of wells having been lost through time. These lost wells are potentially risk drivers because of the high uncertainty associated with them. In PENS, the user is allowed to specify a file with locations of known wells, and unknown wells (also called Random Wells) are generated randomly from user input data, including the x-y bounds of the region where the unknown wells and how many unknown wells there may be. For this example we set the unknown well field to be from 0 < X < 8000 m and 8000 < Y < 16000 with a mean number of 50 unknown wells with standard deviation of 5 wells. Figure 5 shows the locations in the example PENS model for A) known wells and B) Unknown (random) wells. Leakage rates through each well are calculated within PENS using a response tree approach that is built from 1000s of FEHM simulations where the primary variables were allowed to vary over ranges expected for the sequestration application. The resulting leakage tree is built into dynamic link library outside of PENS. Primary variables such as pressure, CO₂ saturation, and temperature at the reservoir top, lengths between the reservoir and overlying aquifers, permeability of a) the reservoir, b) the wellbore sections, and c) the overlying aquifers are passed into the response tree and a value for a leakage rate (kg/s) of both CO₂ and brine is passed back to PENS. The leakage algorithm is called at each time step thus creating a piecewise continuous approximation to leakage as pressure, CO₂ saturation, and temperature change during the evolution of the injected CO₂ plume. For the example presented, we assign each of the known and unknown wells to be of the
leakiest class of wells available in PENS, those that are basically open holes, with an effective permeability of between $10^{-12}$ and $10^{-10}$ m$^2$ with a mean of $10^{-11}$ m$^2$.

b. **Leakage pathways – Faults**

Fault geometry and locations are developed in CO$_2$-PENS using Monte Carlo methods. A fault swarm feature is defined as a group of faults with a resolvable center (centroid) (Figure 6a). Faults in a swarm share a common mean strike angle, each with a minor angular deviation. Using statistical input data, an elliptical area in the model domain is randomly populated with individual faults. After each new fault is added, the algorithm performs several investigative walks parallel to the minor axis of the ellipse to determine if the required fault density (faults per km) is satisfied (Figure 6b). A series of leakage pipes is distributed along the fault plane according to a user-defined spacing parameter, and x-y coordinates are stored for each fault pipe \[14\]. Any leakage pipe that falls outside the ellipse is subsequently truncated. The remaining pipes are then rotated and translated from the origin to satisfy the swarm geometry parameters. All pipes that fall outside the model domain following translation and rotation are removed.

Leakage along the fault pipes is then computed within PENS using the same algorithm as used for the well leakage; however the fault permeabilities are computed using a not yet published algorithm that includes terms for total fault displacement and anisotropic reductions and enhancements to permeability along and perpendicular to the fault plane \[15\].

Figure 7 shows the locations of the faults generate for the example problem, where the centroid is located at (11 km, 11 km) with a major axis of 10 km and a minor axis of 3 km. Fault length is 6 km with pipe spacing of 1 km. Although each fault has only a few pipes representing its length, each of these pipes has a fairly large area and thus leads to greater leakage than seen in boreholes. Each of the figures presented so far for model output (5and 7) represents just one of the many stochastic realizations used in the model results presented below, thus some realizations have more or less fault pipes or leaky wells than shown.

5. **CO$_2$-PENS Model Results**

This section shows results from CO$_2$-PENS for the hypothetical leakage calculations which are based on the 3-D geologic framework model, 3-D multiphase injection simulations, and leakage pathways described above. We reiterate that these results are hypothetical because they are based on leaking wells and faults generated specifically for demonstration purposes. Any planned location for actual injection in the RSU would require detailed site specific data to be gathered to help populate the PENS model.
a. **Time-history plots**

Results in CO\textsubscript{2}-PENS can be output in several formats. Global variables such as total CO\textsubscript{2} or brine leaked are most often displayed as either time-history plots or probability density functions (PDFs) or cumulative distribution functions (CDFs). The time history plots usually show the mean of the total number of realizations run, which in our case is fifty, and can also be modified within GoldSim to show the 5-95% confidence ranges. Figure 8 shows a time history plot for total CO\textsubscript{2} leakage resulting from all pathways in the scenario described above, and includes estimates of both the 5-95% and 25-75% confidence bounds for the 50 realizations that were run. The combined uncertainty from this example shows that total CO\textsubscript{2} leakage out of the storage reservoir into overlying aquifers is very likely to be between 0.06 and 0.08 MT after 200 years. The rate of increase in the leakage for all cases follows a similar pattern, where the slope changes dramatically after 50 years, coincident with the time injection is stopped. This can be seen clearly from Figure 9, which shows the excess pore pressure ratio in the center of the plume as a function of time. Excess pore pressure ratio is defined as the (current pressure – initial pressure)/(maximum total pressure – initial pressure). The change in this ratio clearly shows that the driving force for CO\textsubscript{2} and brine migration decays quickly after the injection is ceased. Figure 10 shows total leakage into each of the overlying aquifers for both CO\textsubscript{2} and brine as a function of time. The average CO\textsubscript{2} leakage into the first overlying aquifer is nearly an order of magnitude higher than the leakage into the next aquifer. This is in large part due to the pressure gradients driving the flow and the ability of the first aquifer to act as a thief zone for rising fluids. The brine plot does not show this effect, partly because the resolution of the response tree for brine leakage is coarser and the leak
rates into aquifers 1 and 2 often fall onto the same branch, thus resulting in similar leak patterns. We finish this section by showing a typical PDF output for the total amount of CO2 leaked through all the wells in the model domain. This figure shows that the wells leak between about 5000 tonnes to 25000 tonnes, an amount that is much smaller than the total leaked, meaning that the faults in this model are the drivers for most of the leakage risk. Figure 12 confirms this showing that the faults leak between 53000 to 56000 tonnes. The very small axis numbers on the vertical axis are a result of the bin widths on the horizontal axis, with the requirement that the integration across the figure must equal one.

b. **CO2-PENS spatial output**

We conclude the results section with a description of the spatial output from the simulations. Figure 13 shows the locations of all CO2 leaks into the first aquifer, scaled by the estimated radius of the plume. The radius scaling uses equation (4) from [11] to compute radius as an average value based on the total mass leaked into a given bin of the aquifer. The model integrates all sources of leakage for a bin, and corrects mass flow rates to volume using the pressure and temperature of the aquifer. The computed radii are all on the order of 10 m or less due to the low total mass flux into these bins. The figure shows clearly that the faults dominate the leakage of CO2 in this model, although some leakage of CO2 can be seen in the random well field located to the left of the fault leakage.

Figure 14 shows the spatial locations of brine leakage, scaled by bubble plot such that any leaks with total mass of greater than 1e7 kg plot as 1/100 the total axis size, greater than 1e6 as 1/150, etc to very small leaks of less than 1e4 plotting as 1/500 the domain extent. It is clear from this figure that many more wells are impacted by brine than are impacted by CO2. This result is not surprising given that the pressure pulse from injection travels much further and more quickly than the injected CO2. In fact, it appears from the image that brine is leaking through all chosen pathways in the domain, a result that is not unexpected given that we have assigned very leaky properties to all wells and given the faults in the model sufficient slip and length to allow leakage.

6. **Conclusions**

- The ability of CO2-PENS to include site specific details provides a way of visually assessing output and can greatly aid in describing the model to regulators and stakeholders. This feature also allows users to quickly determine if their model is doing what they think it should.
- Simulations of leakage, although hypothetical, show the need for high resolution characterization of the subsurface and the usefulness of sites that have little probability of faulting or existing wellbores.
References


