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Expanding the Potential for Saline Formations: Modeling Carbon Dioxide Storage, Water Extraction and Treatment for Power Plant Cooling

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ABSTRACT

The National Water, Energy and Carbon Sequestration simulation model (WECSsim) is being developed to address the question, "Where in the current and future U.S. fossil fuel based electricity generation fleet are there opportunities to couple CO_2 storage and extracted water use, and what are the economic and water demand-related impacts of these systems compared to traditional power systems?"

The WECSsim collaborative team initially applied this framework to a test case region in the San Juan Basin, New Mexico. Recently, the model has been expanded to incorporate the lower 48 states of the U.S. Significant effort has been spent characterizing locations throughout the U.S. where CO_2 might be stored in saline formations including substantial data collection and analysis efforts to supplement the incomplete brine data offered in the NatCarb database. WECSsim calculates costs associated with CO_2 capture and storage (CCS) for the power plant to saline formation combinations including parasitic energy costs of CO_2 capture, CO_2 pipelines, water treatment options, and the net benefit of water treatment for power plant cooling. Currently, the model can identify the least-cost deep saline formation CO_2 storage option for any current or proposed coal or natural gas-fired power plant in the lower 48 states.

Initial results suggest that additional, cumulative water withdrawals resulting from national scale CCS may range from 676 million gallons per day (MGD) to 30,155 MGD depending on the makeup power and cooling technologies being utilized. These demands represent 0.20% to 8.7% of the U.S. total fresh water withdrawals in the year 2000, respectively. These regional and ultimately nation-wide, bottom-up scenarios coupling power plants and saline formations throughout the U.S. can be used to support state or national energy development plans and strategies.

1. Introduction

The Water Energy and Carbon Sequestration simulation model (WECSsim) is being developed to integrate data that would help address the question, "Where amid all of the coal and natural gas power plants in the U.S. may there be opportunities to store CO_2 in subsurface saline formations while also extracting and using water from these formations?" The Integrated Assessment WECSsim model, developed in Powersim Studio, also includes several years' worth of effort collecting and addressing standardization and data quality issues in the project's first three phases. In Phase I of the project, the team developed a framework to assess a specific source of CO_2 (a plant similar to the San Juan generating station in northwest New Mexico) to a specific saline formation to store the CO_2 (in the Morrison formation also in northwest New Mexico) (Kobos et al., 2008a, 2008b, 2009). In Phase II, the project included other regions of the U.S. (Kobos et al., 2009, 2010a). In Phase III, the project worked to address data collection and quality control issues with the potential use of saline formations to store CO_2 while at the same time extracting and treating saline waters to be used as supplementary cooling water for power plants (Kobos et al., 2010b, 2010c)

In Phase IV presented here, the larger national-level WECSsim model evaluates CO_2 capture and compression at any coal or natural gas-based power plant in the U.S. and storage of that CO_2 in any of 325 deep saline formations that have been derived from the NatCarb (2008) Atlas. The estimated parameters include the costs associated with CO_2 capture, compression and storage (CCS), the distances between the power plants and potential sinks, formation lifetime for a given rate of CO_2 injection, and the potential costs of water treatment to reuse the extracted water as a way to offset additional water demands at the power plant associated with CCS.

A notable model development in Phase IV involves simulating the required injectivity of CO_2 into various types of saline formations and their respective strata. Specifically, an effort is underway to develop a type of standardized class of injectivity per rock type based on common practices in the geosciences. With this type of standardization, the modeling effort will be able to more accurately address the potential for injectivity to alter (e.g., limit) the flow of CO_2 to given rates which affect the overall system's economics. For example, low injectivity due to relatively low permeability may result in greatly increased systems costs and impact the overall economic viability under certain conditions.

Building on this full analysis, multiple scenarios are being developed so the model can be used to evaluate CCS with extracted water treatment at all currently operational coal and natural gas fired power plants in the U.S. This paper describes the modeling efforts to date and addresses capabilities currently under development.

2. Analysis of NatCarb Data

2.1. Data Required for Storage Resource Quantification

In order to estimate pore volumes associated with potential CO_2 storage resources requires information on total formation volume and porosity. To estimate the mass of CO_2 that might be sequestered in that pore space requires CO_2 density information and a sweep efficiency parameter (representing the portion of pore space that can be realistically occupied by CO_2). While the sweep efficiency is formation and injection method dependent, the CO_2 density is a function of formation specific properties of pressure and temperature, which are both functions of depth. Finally, water quality concerns associated with injection and water re-use require some estimate of water salinity in the pore space prior to injection. Thus, in order to more accurately evaluate deep saline formations in terms of storage resource potential, formation specific properties of area, thickness, porosity, depth (from which temperature and pressure can be reasonably estimated), and water salinity are required.

2.2. Data available in NatCarb (2008) and from Partnerships

Sandia National Laboratories has processed the NatCarb (2008) spatial database in a way that spatially aggregates polygon representations of saline formations that were originally split due to political boundaries or raster representations initially created from the regional sequestration partnerships (Partnerships). This work resulted in 325 polygons representing the potential CO_2 storage resource within subsurface saline formations of the 2008 NatCarb database. Unfortunately, aside from the two dimensional spatial extent of these polygons, other required attributes for necessary characterization of these potential sinks are not provided. Total storage capacity estimates are given within the geodatabase for 136 of the 325 polygons (42%) (NatCarb 2008), but other formation attributes necessary for our analysis are not included (See row 2 of Table 1 below). However, while this data was limited in the NatCarb (2008) saline formation spatial database, some data gaps were filled in by direct communication with the Partnerships, including cross-checking with the many reports and available data as reported by each Partnership on their websites.[1] Other data gaps were filled using the Texas BEG Brine Formation Database (BEG, 2000), and saline well data utilized by the Partnerships (KGS, 2006). In some cases, published literature was used in locations where detail was not otherwise available. An example is provided below in Section 2.5. Information that was gathered includes storage capacity estimates for an additional 135 (41.5%) polygons, depth information for 200 polygons (62%), thickness information for 208 polygons (64%), porosity information for 178 polygons (55%), salinity information for 59 polygons (18%), temperature information for 142 polygons (44%), and pressure information for 146 polygons (45%). (See row 3 of Table 1 below).

	CO2 storage capacity	Area	Depth	Thickness	Porosity	TDS	Temp	Pressure
NatCarb 2008 geospatial database	42%	100%	0%	0%	0%	0%	0%	0%
Carbon SQ Partnerships	42%	100%	62%	64%	55%	18%	44%	45%
Estimates based on well records	NA	NA	70%[1]	70%[1]	0%	70%[1]	100%[2]	NA
Estimates based on geo. class	NA	NA	NA	NA	? %[3]	0%	NA	NA
No estimate	**16%** (52)	**0%** (0)	**14%**[4] (47)	**14%**[4] (47)	**0 - 45%** (0 -)	**14%**[4] (47)	**14%**[4] (47)	**14%**[4] (47)

Table 1. Data availability by parameter and source for characterization of the U.S. deep saline formation storage resource. (Notes: (1). 30% of polygons (97 of 325) have no potentially intersecting wells associated with them from well databases used here. (2). Temperature calculated from depth and geothermal gradient. Geothermal gradient was developed spatially from publically available well records. (3). Current attempts to classify all 325 polygons according to geology may not result in reliable data estimates for all polygons. (4). 14% of polygons (47 of 325) have no depth, thickness, or salinity information and no potentially intersecting wells.)

[1] The following NETL website has links to each Partnership: http://fossil.energy.gov/sequestration/partnerships/index.html

2.3. Data available from well records

To address the limited data available, well records were selected for all wells with latitude and longitude within the footprint of the saline formation polygons defined by NatCarb (2008). These wells are termed "potentially intersecting wells" because although they will fall within two dimensions of a saline formation footprint, they may not intersect the polygon in the depth dimension. Two methods were used to estimate saline formation properties based on this dataset of potentially intersecting wells. In the first treatment, a completely automated method using all potentially intersecting well records was used to develop estimates of depth, thickness, and salinity distributions in the saline formation polygon. A set of Matlab scripts was developed to cycle through the potentially intersecting wells for each formation, calculate salinity distributions at user defined depth intervals, calculate average depth information, and calculate average thickness as the difference between available top depth and bottom depth fields in each potentially intersecting well record. The second method relied on a case by case analysis of formations and potentially intersecting wells in order to create a refined or "intelligent" set of well records that are likely to be associated with a given formation based on geologic information associated with the well record and polygon name. This method was very time consuming, and thus was implemented only on polygons for which there was no depth or thickness information available from the Partnership in question.

If depth is known, saline formation temperature information can be estimated based on the geothermal gradient. Geothermal gradients associated with each NatCarb saline formation were calculated by creating a geothermal surface with publically available well data,[2] and intersecting that surface with the 325 saline formation polygons.

2.4. Data available from geologic classification

With the methods and data sources described above, area, depth, thickness, salinity, and geothermal gradient data requirements for the 325 defined saline formation polygons were partially filled. Porosity information was available from the Partnerships for more than half of the formations (described previously), however a majority of that data is an estimate based on depth rather than actual site specific observations as can be seen in Figure 1. In addition, though not directly related to total storage resource size, resource quality will depend on formation permeability and the resulting ability to inject CO_2 into the formation. For these needs, methods to estimate porosity and permeability as a function of geologic class are being pursued as described in more detail later in this paper.

Taken together, a wide range of information is available from the NatCarb (2008) geospatial database, the Partnerships, well record analysis, and geologic classification. These data sources and their contribution to the overall analysis are shown in Figure 2 and Table 1.

[2] A digital version of the 2004 geothermal map (http://smu.edu/geothermal/2004NAMap/2004NAmap.htm) was not available for analysis. For our purposes, we created one based on the underlying well data available at this location: http://smu.edu/geothermal/georesou/08%20Data/SMU_heatflowdatabases9_2008.xls

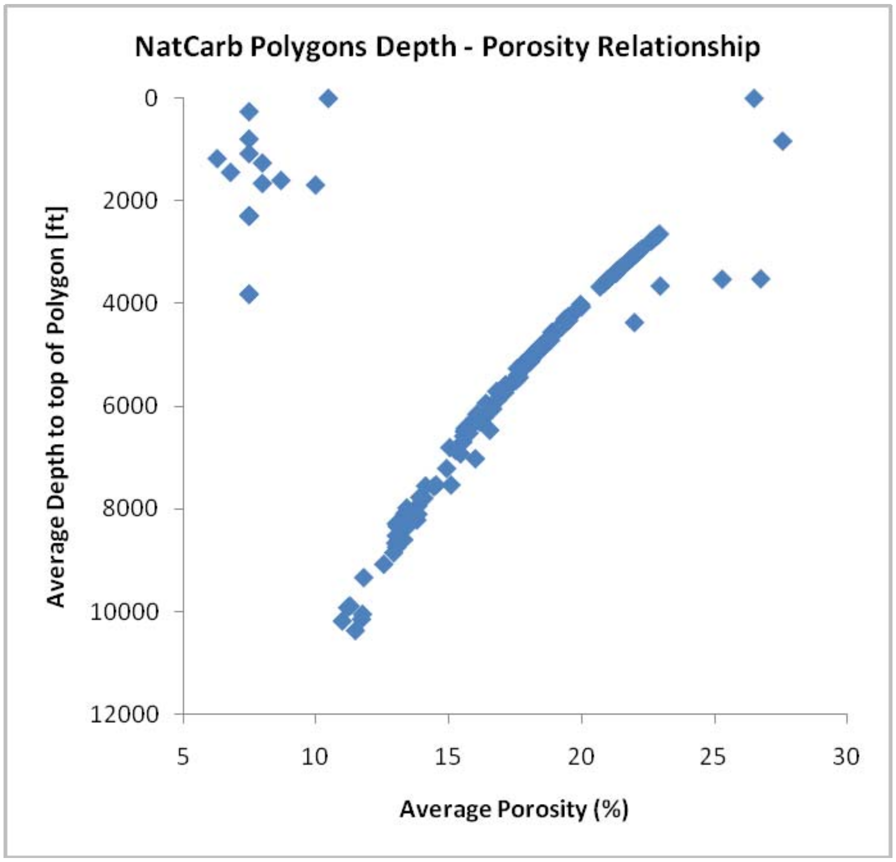

Figure 1. Reported depth and porosity data from NatCarb Partnerships. The distinct line on which most of the data falls suggests porosities estimated by depth using an equation rather than actual formation specific porosity data.

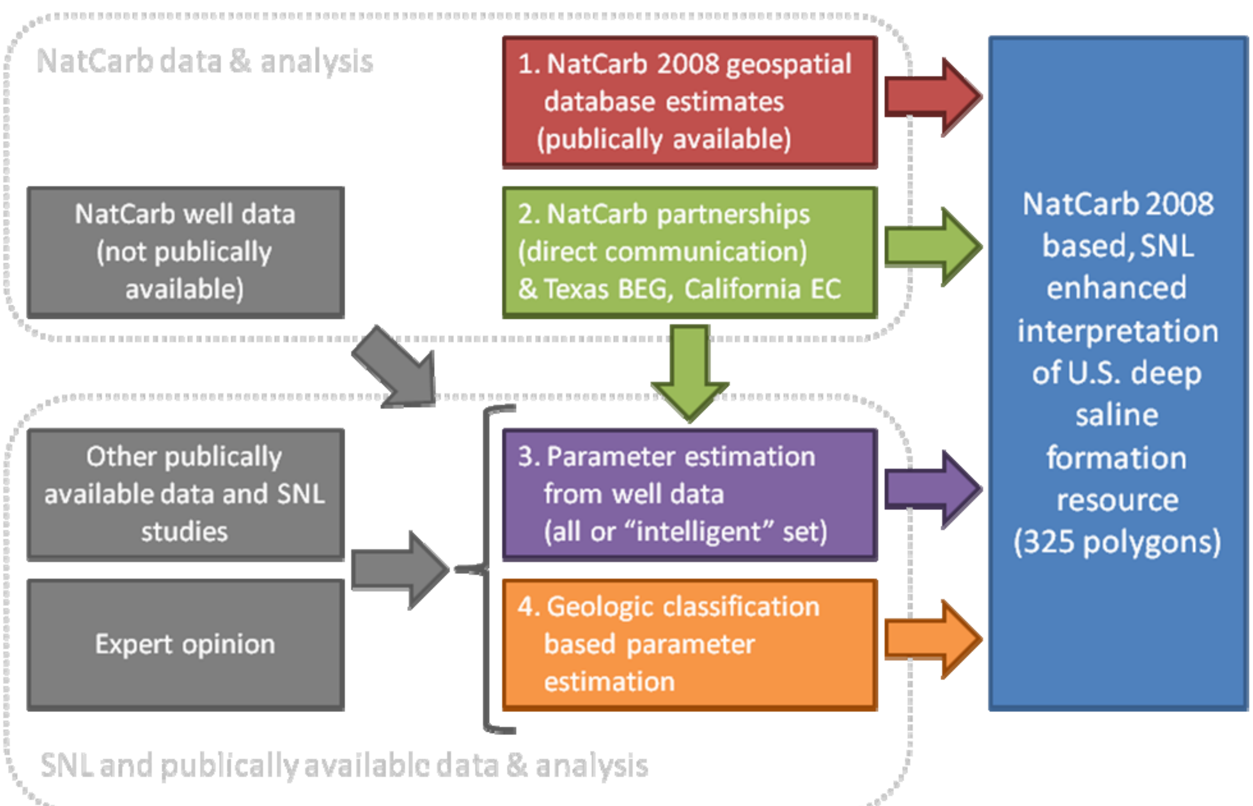

Figure 2. Sources of data and analysis used to inform a NatCarb (2008) based, Sandia National Laboratories enhanced interpretation of the U.S. deep saline formation storage resource.

2.5. Data Challenges – Offshore Atlantic

In some cases difficulty arises when assigning properties to saline formations where there are no intersecting wells. A prime example here concerns the large saline formations lying offshore along the southern Atlantic seaboard where there is significant fraction of the U.S. population, and associated carbon-producing infrastructure. However, the on-shore bed-rock geology consists of the crystalline core of the Appalachian Mountains so the offshore option is the only available regional saline formation resource for CO_2 sequestration.

When data was needed but not available from NatCarb (2008) or the Partnerships, this problem was approached by accessing information from published geologic records. Specifically, Poag (1978) and Watts and Thorne (1984) provide cross-sections of the offshore sediments that we are utilizing from NatCarb (2008) and including in our analysis. These data sources identified the lower Cretaceous interbedded sandstones and shales as being the units likely to have the porosity and upper seal needed for CO_2 sequestration. These sources also suggested a median depth of around 8,000 feet and a thickness near 3,000 feet. From lithologic descriptions, at least 10% of the sediments are porous enough to be of use (e.g., medium to coarse sands), which provides the operational thickness (~ 300 feet) needed by the model.

Since no wells are available from this saline formation, geologic extrapolations of similar depositional environments were utilized to provide representative salinity distributions. The sedimentary pile for the Offshore Atlantic saline formations is similar to the sediments along the Gulf of Mexico, where there is a large amount of data due to the number of hydrocarbon producing fields. As a first approximation, we utilized the salinity distribution for the Gulf Coast Eocene Pliocene formations as it produces brines from over the same depth interval as is spanned by the Offshore Atlantic formations.

3. Impact of Geological Heterogeneity on Well Injectivity

Due to large, natural variation in properties such as permeability and porosity, some geologic formations are more suited for CO_2 storage and saline water extraction than others. A goal of WECSsim is to assess the economic and regional-scale implementation impacts of geologic heterogeneity on the number of wells needed for CO_2 storage and saline water extraction for power plant cooling. Our approach is to use well injectivity and productivity indexes, which are common metrics in petroleum engineering. These indexes provide a measure of the flow rate into or out of a well for a given pressure gradient and geologic properties. As geologic data are limited and uncertain, we use geostatistical methods to generate probability density functions (pdfs) of well injectivity that WECSsim can sample stochastically to determine the likelihood of the number of wells needed and associated costs for sequestration-water extraction scenarios.

Numerical modeling of multiple geostatistical realizations of formation properties for several formations would be very time-consuming and thus intractable for the purposes at this stage of the project. Thus, here we present methods for calculating well injectivity using an analytical equation and averaging scheme that captures geological heterogeneity of multiple realization of formation properties. The Mount Simon Sandstone of the Illinois Basin is the test case. We are in the process, however, of running a set of numerical simulations to evaluate the veracity of our analytical-averaging scheme.

The injectivity and productivity indexes *I* and *J* are expressed as, respectively (Ezekwe, 2011):

$$I \stackrel{\text{def}}{=} \frac{q_I}{p_{wmf} - \bar{p}} \quad (1)$$

$$J \stackrel{\text{def}}{=} \frac{q_J}{\bar{p} - p_{wf}} \quad (2)$$

where q is the volumetric flow rate of the injectant (subscript I) or produced fluid (subscript J); p_{winj} is the injection pressure at the midpoint of the injection interval; p_{wf} is the flowing bottom-hole pressure measured at the midpoint of the producing interval; and $\bar{p}$ is some reference pressure, typically the average reservoir pressure. Estimates of q can be obtained via analytical equations or numerical simulations of fluid flow in the reservoir. For efficiency of the WECSsim model, we use analytical solutions to the flow equations.

Analytical solutions for partial differential equations of fluid flow into or out of a well are given by Wattenbarger (1987). Solution assumptions may limit their use in WECSsim, and thus we are completing simulations with TOUGH2 (Pruess et al., 1999) for comparison. We discuss the assumptions here and how the equations should be used in WECSsim. The performance of a constant-rate production well in a closed reservoir of any geometry or heterogeneity of rock properties follows the behavior show in Figure 3. Wattenbarger (1987) provides solutions for the flow rate for the early time region (ETR), based on two-dimensional radial flow into a homogenous, infinite reservoir. The middle time region (MTR) solution is based on the same assumptions, except that the reservoir is assumed closed, meaning that boundary effects cause the pressure profile to deviate from the infinite-acting case, and the rate of change is pseudosteady-state. We propose that the flow rate equation for MTR is appropriate for use in WECSsim, which is being tested with TOUGH2 simulations.

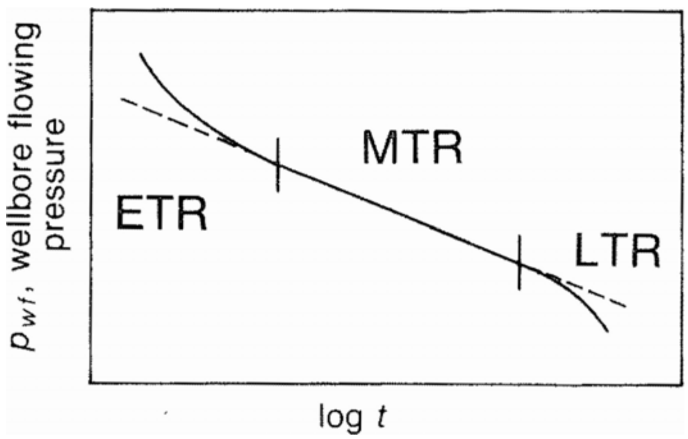

Figure 3. Flowing pressure versus time for a typical constant-rate production well (after Wattenbarger, 1987). ETR = early time region; MTR = middle time region; and LTR = late time region.

The solutions for MTR for a circular injection or production area of a closed reservoir with a possible damage zone around the well are the following (after Wallenbarger (1987) with English units):

$$I = \frac{7.08 \cdot 10^{-3} k k_r H}{\mu \left(0.5 \ln\left(\frac{2.2458}{C_A}\frac{A}{r_w^2} + s\right)\right)} \quad (3)$$

$$J = \frac{7.08 \cdot 10^{-3} k H}{\mu \left(0.5 \ln\left(\frac{2.2458}{C_A}\frac{A}{r_w^2} + s\right)\right)} \quad (4)$$

where k is absolute permeability (mD); k_r is relative permeability; H is the vertical thickness of the injection or production interval (ft); μ is viscosity (cP); C_A is a shape factor (ft^2); A is the area flooded by the injectant or drained by the production well; r_w is the wellbore radius (ft), and s is the skin factor. These are the forms of I and J for implementation in WECSsim. Note that I applies to multiphase conditions due to the presence of the relative permeability in the equation, which accounts for CO_2

injection into a brine-bearing formation. At MTR, we assume that the brine is at irreducible saturation (meaning that brine may still occupy pore space, but the brine does not flow or change saturation), which aids in the determination of the value of k_r. The *J* equation applies to single phase flow of brine out of the reservoir. The pressure gradient is part of the equation for the flow rate, which cancels out when placed in the *I* and *J* equations. The shape factor accounts for different areal geometries for the bounded reservoir. The user of WECSsim will be able to choose a shape factor for the well spacing scheme.

We incorporate heterogeneity by supplying pdfs of k and k_r values that correspond to averaged permeability fields of multiple (~100) realizations of the formation in question. For the first test case of the well injectivity method, we are generating geostatistical realizations of permeability of the Mount Simon Sandstone in the Illinois Basin. We use the software GSLIB Geostatistical Software Library and User's Guide (Deutsch and Journel, 1998), namely the Sequential Gaussian Simulation (sgsim) algorithm, to obtain permeability fields for the domain of CO_2 injection. Input parameters for sgsim include mean porosity and its standard deviation, and the nugget, sill, and range of a semivariogram for this formation. Permeability is estimated through a coregionalization method that uses a linear relationship between porosity and $\log_{10}$ permeability (Rautman and McKenna, 1997), as implemented by a program from McKenna (pers. commun., 2010). This coregionalization method maintains the relationship between porosity and permeability in terms of the r^2 value of the regression. We obtained the necessary parameters for the Mt. Simon Sandstone from Media et al. (2011) and Finley (2005).

Figure 4 presents two out of a set of 100 geostatistical realizations of permeability *k*. The spatial correlation of hotter and cooler colors indicates zones that constitute high permeability pathways and much lower permeability, respectively. If a well were placed at the left hand side of both of these realizations, Realization 19 would have higher well injectivity since it has a greater number of blocks with high permeability close to the well as compared to Realization 78.

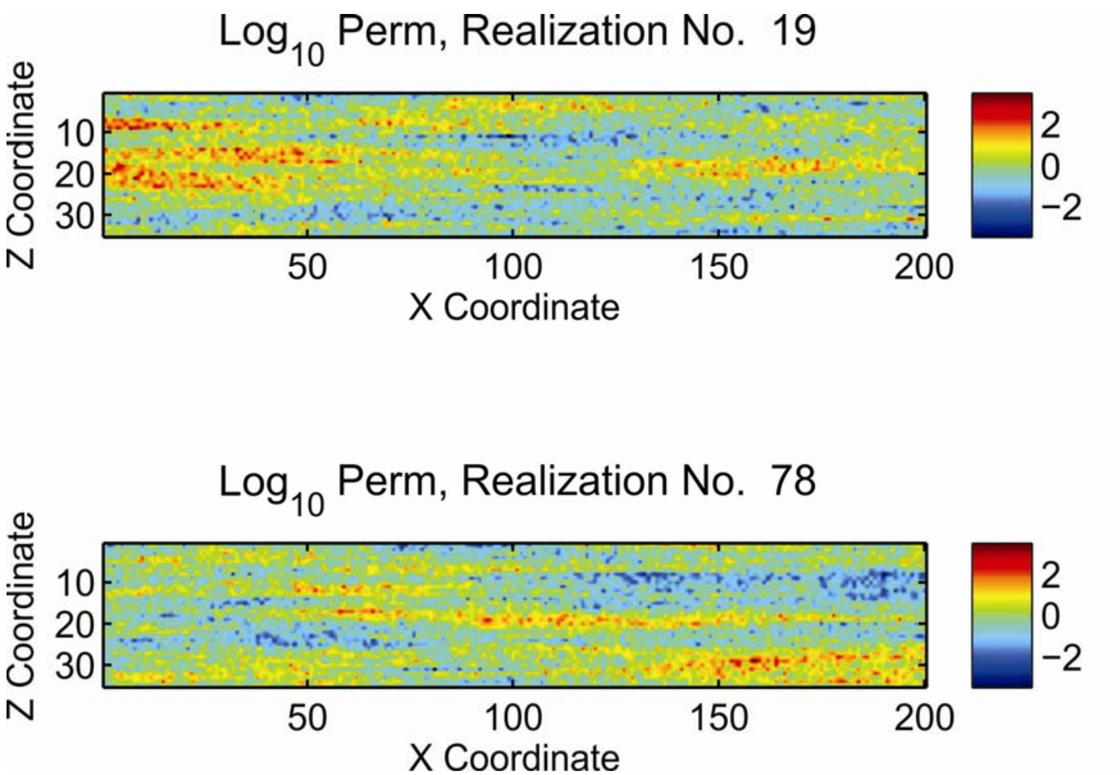

Figure 4. Geostatistical Realizations No. 19 and 78 for the Mt. Simon Sandstone from a batch of 100 realizations. The horizontal domain is labeled with the number of grid blocks, which represents 2000 m. The grid blocks are 1 m in the vertical direction, totaling 35 m. The color scheme represents variation in $\log_{10}$ permeability *k*. Hotter colors represent higher permeability portions of the formation.

The averaging scheme of *k* for the whole domain envisions that CO_2 is injected from the left side of the domain. Since the CO_2 would initially flow out from the well horizontally, we propose that a weighted-harmonic mean is appropriate for averaging the grid blocks that are located in serial, in the horizontal direction from the left side of the domain (the location of wellbore). Weighting of the harmonic mean is needed since the impact of permeability on injection will be greatest for those grid blocks that are closest, horizontally, to the wellbore. The weighting term is chosen to be 1 at the wellbore and to decay to zero as the distance from the wellbore goes to infinity. We chose a $1/(1+r^2)$ weighting term, where r is the distance from the wellbore. The validity of this weighting term is being tested by on-going TOUGH2 simulations. The harmonic means are then arithmetically averaged to obtaine the upscaled value of *k* for the whole domain. A similar approach will be used for relative permeability, while taking into account assumptions related to capillary pressure and fluid saturations.

Figure 5 presents a relative frequency histogram for 100 averaged *k* values, based on 100 geostatistical realizations. To evaluate if our approach does indeed generate statistically-sound pdfs, we average the parameter of interest (e.g., averaged *k* values) as a function of the number of realizations. The curves of Figure 6 present five batches of 100 realizations. We suggest that approximately 60 realizations need to be averaged to obtain a statistically meaningful pdf. The well injectivity pdfs are sampled by WECSsim and used in analysis of the number of wells and associated costs for a particular formation of interest and given rate of CO_2 to be sequestered. Similar methods are being implemented in WECSsim for saline water extraction.

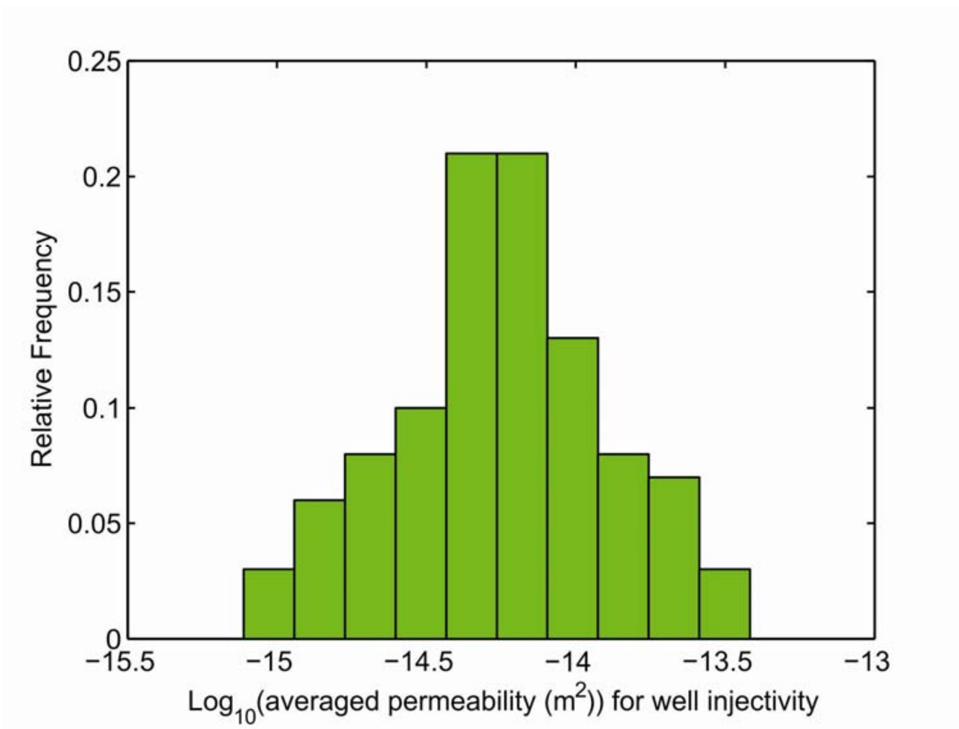

Figure 5. Example of a relative frequency histogram of the averaged permeability *k*, based on 100 realizations, which could be used in the well injectivity equation.

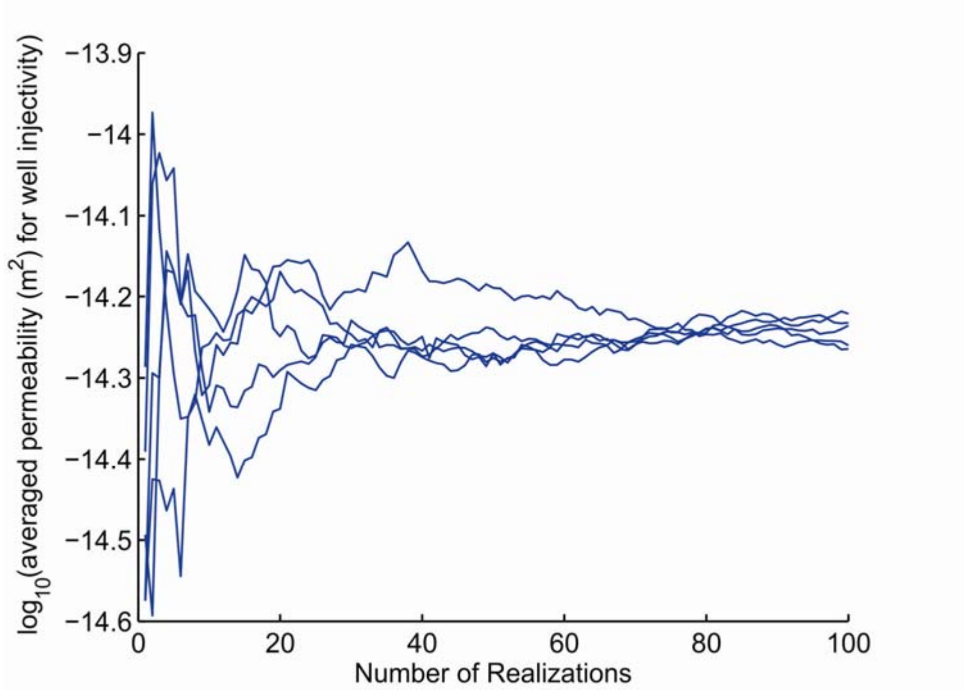

Figure 6. Plot of the averaged value of *k* as a function of the number of realizations for five batches of 100 realizations. Each set of realizations was started with a different seed (meaning that each set begins as a different realization). We suggest that at least 60 realizations are needed to obtain a statistically stable relative frequency histogram, such as that given in Figure 5.

4. Linking of Well Injectivity Data into WECSsim

Sandia National Laboratories, with guidance and support from the National Energy Technology Laboratory (NETL), is creating the WECSsim model to evaluate the potential for a combined approach to saline formations: as a sink for CO_2 and a source for saline waters that can be treated and beneficially reused to serve power plant water demands. WECSsim is being developed to connect power plant (CO_2 source) information to the potential geologic sink information described in the previous sections of this paper. WECSsim has five modules: a power plant module, a carbon capture module, a carbon sequestration module, an extracted water module, and an integrating power costs module. WECSsim model inputs include power plant information, level of CO_2 capture desired, and type of power plant used to make-up for parasitic losses (make-up power). With these inputs, WECSsim calculates CO_2 capture rate, and queries the potential storage polygons described above to find a suitable target sequestration formation which is used to populate default inputs to the carbon sequestration module and the extracted water module. WECSsim then uses default or user specified inputs to all five modules to calculate energy, water, and economic costs associated with the selected carbon capture and sequestration scenario. See Kobos et al 2010b for additional description of the overall modeling framework of WECSsim.

An initial analysis by Roach et al. (2010) focused on using information on coal fired power plants from the eGRID2007 (EPA, 2007) database for the 2005 U.S. power plant fleet to populate the WECSsim power plant module. Plant latitude, longitude, capacity, capacity factor, and CO_2 production rate values from eGRID2007 were used. Plant elevation was derived using a digital elevation model at each of the power plant locations. Baseline water use estimates for each plant was taken from Tidwell et al. (2009). Each of 556 plants was evaluated under 6 different scenarios related to make-up power and make-up power cooling technologies. The scenarios are shown in Table 2 below. In all cases, CO_2 capture was specified as 90% of emissions at the original and make-up power plants. Sixty-three of these power plants are located further than 150 miles from a viable sequestration and extraction formation, and were not included in the final analysis. (This does not mean there are no CO_2 storage options for these plants, only that there are no currently characterized formation options with water quality feasible for treatment and reuse.) WECSsim was used to calculate changes to water demand and saline supply for each power plant. The summation of results provides insights into the magnitude of new water demands and potential supplies resulting from carbon capture at coal fired power plants with sequestration to deep saline formations and reuse of water extracted as part of the sequestration process.

Scenario # and Code		Make-up Power Type	Make-up Cooling Type	SalineWater Use
1a.	SSN	Same as original plant	Same as original plant	No
1b.	SSY	Same as original plant	Same as original plant	Yes
2a.	STN	Same as original plant	Cooling Tower	No
2b.	STY	Same as original plant	Cooling Tower	Yes
3a.	ITN	IGCC	Cooling Tower	No
3b.	ITY	IGCC	Cooling Tower	Yes

Table 2: Make-up power generation and cooling technologies along with saline water re-use options selected for each of the six scenarios considered for water use related analysis.

Results for each scenario were ranked by the added water withdrawals required per unit of reduced atmospheric CO_2 emission, and summed to give cumulative water withdrawal costs per cumulative avoided CO_2 emissions. These lines are shown in Figure 7 below, and can be thought of as the least water intensive order of power plant carbon capture implementation for a given make-up power and cooling (MUP&C) scenario. By far the most water intensive carbon capture scenarios considered are 1a and 1b which utilize once through cooling for make-up power (MUP) generation for plants to the right of the inflection point, resulting in substantially higher increases in water withdrawal than all other scenarios. Note the logarithmic scale of the y-axis, used because of the size of this relative difference. In a situation where water is available for once through cooling of MUP, saline formation water use would be an expensive option, and would likely be put to a higher value use. The two least water intensive scenarios are 2b and 3b where MUP is cooled with cooling towers, and saline formation water is used. Scenario 3b results in cumulative water withdrawals less than 1 MGD for the first 97 million metric tons per year of avoided atmospheric CO_2 emissions and thus does not show up on the log plot until that point.

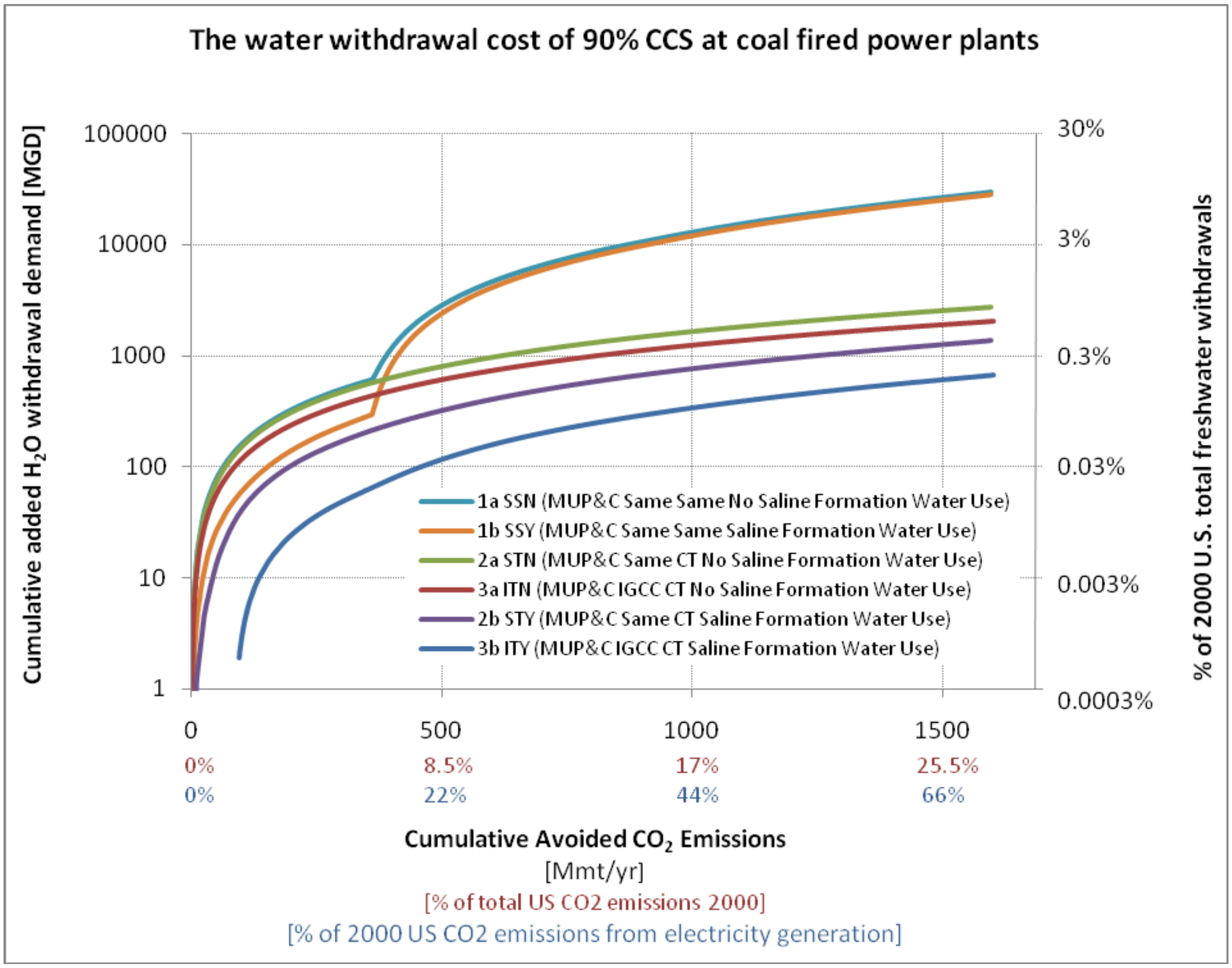

Figure 7: Cumulative additional water demands associated with cumulative reductions in CO_2 emissions by CO_2 capture from coal fired power plants and geologic sequestration. The lines represent the most water efficient way to avoid CO_2 emissions in this manner with different lines representing different assumptions as to make-up power technologies and use of saline formation water.

In locations where water supplies are constrained, using treated saline formation waters to supplement the added water withdrawal demands required to capture CO_2 may offset some of this demand. This management option is a more important factor than the type of MUP generation technology. Thus, while generating make-up power at tower cooled IGCC power plants and utilizing water extracted from the sequestration formation might be the least water intensive scenario, it is currently not the most cost effective.

To more fully address the entire CO_2 capture and storage system beyond the water requirements, WECSsim incorporates costs associated with CO_2 capture systems coupled with treated saline formation water extraction and use. These costs assume an injection well capacity of 2,500 metric tons per day regardless of saline formation sink geology, that itself is based on the assumption the well bore is the limiting factor to injection flow (Ogden 2002). This assumption can be relaxed by incorporating permeability distributions developed according to the methods described previously and by including a pipeflow model for injection flow. Once these distributions have been incorporated, the model will first be run in deterministic fashion by taking an average value for permeability in order to create a figure similar to Figure 7 that shows least cost path rather than least water intensive path to a given reduction in CO_2 emissions. Next, the permeability distributions will be sampled in multiple runs to estimate a distribution of costs associated with a given CCS scenario with variability from geologic uncertainty.

Finally, other parameters will also be assigned a range of likely values to analyze combined parameter uncertainties on the distribution of model outputs. The result will be a supply curve with ranges of uncertainty representing the least cost path to a given reduction in atmospheric CO_2 emissions.

5. Concluding Discussion and Future Efforts

To further the goal of assessing the impact of geologic heterogeneity on injectivity-productivity and economic uncertainty, the well injectivity-productivity methods will be applied to as many saline formations as possible. One challenge is that data required for the injectivity-productivity calculations are not readily available for all 325 saline formations. The necessary data include permeability and porosity distributions (i.e., mean values and standard deviations), a functional relationship between the two (e.g., a straight line with a correlation coefficient), and a description of spatial correlation (i.e., a semivariogram) for porosity. Our data collection efforts indicate that the spatial correlation data are the least available at this time. Our current approach to work with limited data is to classify the polygons into a small set of rock types based on depositional environment and/or other geologic properties. These rock types will represent specific distributions of permeability and porosity, and spatial correlation of porosity. The well injectivity methods will be performed on these rock types, which will then be linked to the appropriate polygons within WECSsim thereby enabling WECSsim to evaluate the economic uncertainty associated with the geologic heterogeneity of the saline formations.

Additionally, we are also currently working on additional visualization capabilities of model results in a way that shows a geographic representation of the model results as a function of the different combinations of CO_2 source and sink. These capabilities will enhance the overall model results and present information in a way that can be useful to decision-makers.

Thus, in spite of data challenges for the combined CO_2 storage and water extraction and treatment analysis, the team has been moving forwards with supplementing the data where available, and applying statistical techniques to address these challenges. While just a start, the larger WECSsim national level model will benefit from these techniques to be able to address questions such as, 'Where are opportunities to store CO_2 in saline formations while at the same time extracting, treating and using saline formation waters to cool power plants?' In cases where there simply is not enough data to reliably develop a tractable case to illustrate a saline formation's geophysical properties, model users may simply indicate 'not enough information' or, if the users have additional data, may enter their own custom set of assumptions to run the national Water, Energy and Carbon Sequestration simulation model scenarios.

With these custom scenarios, model users may be able to develop more detailed regional CO_2 storage potential scenarios at the project, county, region, state or national level depending on their specific needs.

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