Supporting Information for:

A System Model for Geologic Sequestration of Carbon Dioxide

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Summary of Material in the Supporting Information Section

This supporting information section consists of 17 pages containing 1) a description of the function used to calculate maximum injection pressure, 2) a description of the numerical tuning that allows use of an analytical approximaiton to model the injection, and 3) details on the economic module of the system model described in the main manuscript. Specifically, in section 3, we present the underlying calculations and description of the logic used to generate present value costs associated with the two example cases presented in the main manuscript (e.g. Cold-Shallow and Hot-Deep). Included in this section are 7 figures and 1 table and 8 references.

1) Relationship used to calculate maximum injection pressure.

Figure S-1 shows the relationship between lithostatic stress, hydrostatic pressure, and minimum principle stress that is use to calculate the maximum injection pressure for the two cases. The lithostatic stress assumes a porosity of 0.15 and a rock grain density of 2.65×10^3 kg/m^3, while the minimum principle stress is assumed to be 0.65 times the lithostatic. Maximum confining stress is assumed to be vertical and minimum confining stress horizontal. Given these assumptions, the maximum injection pressure before vertical hydrofracture occurs is equal to the minimum principle stress, leading to a maximum injection pressure of 15 MPa for the Cold-Shallow case and 45 MPa for the Hot-Deep case.

2) Tuning used to match the analytical injection solution to a full multiphase numerical solution.

To tune the analytical solution to the numerical solution, injection calculations are performed using FEHM with a 2-D radial grid for different sets of properties, including a range of permeability and porosity discussed in the main manuscript. The analytical model described in section 3.1 of the main manuscript is next used to calculate injection rates for the same combinations of properties. The results of these calculations are plotted as a regression between the analytical and the numerical solutions (Figure S-2). The regression is nearly linear, and for each case, the slope of this regression is used to tune the analytical solution within CO_2-PENS to match the numerical solution calculated using FEHM. This tuning factor is used to replicate the results of the numerical solution using the analytical solution.

3) Description of the economic module

Introduction

The following economic module is designed to show differences in the costs associated with the example simulations presented in the main manuscript. Because the two cases, Cold-Shallow and Hot-Deep, were designed explicitly to show differences in a small subset of a total CO_2 sequestration system directly related to previous published material (Nordbotten et al., 2005), we also confine the scope of the economic analysis to details that are pertinent to differentiating between these two cases. The obvious first difference in the cases is the depth of drilling, where the Cold-Shallow and Hot-Deep cases require 1 km and 3 km drilling depths, respectively. Thus we include an analysis of the costs associated with drilling and completing wells as a function of depth. Secondly, because the two cases result in significantly different numbers of wells required to inject the same mass of $C0_2$ as a function of time, we include an analysis of the costs associated with the pipelines required to distribute the CO_2 around a given field site. Finally, we include estimated maintenance costs associated with both the injection boreholes and the field distribution pipelines.

In this analysis, we assume that for both cases, the initial capital costs (e.g. drilling wells and buying pipeline) will be amortized over a 10 year period. However, maintenance costs must be included for the lifetime of the injection scenario (50 years). Thus each year, the two different cases will have different combined costs. To allow a consistent basis for cost comparison, we use a present value integration that returns all future costs to their present day dollar equivalents before summing to calculate total costs (Grant et al., 1982). This section highlights the economic capabilities available in our system level model (CO2-PENS) and shows how the physics-based injection module can impact the estimated economic requirements for the two cases presented.

Drilling cost analysis

In this section we summarize our approach to estimating the costs of drilling and completing wells for CO_2 sequestration. Limited data exist on drilling wells specifically designed for injection of CO_2 and we assume that drilling costs will be comparable to those of oil wells drilled on-shore in the United States. We use published data on well completion costs from the Joint Association Survey (JAS) of the American Petroleum Institute (API, 2006) for the year 2004. The data are then corrected to the year 2008 using a one year average increase in drilling completion costs of 17% (API 2007), and normalized by the average depth of the reported well (Table S-1). These data are next used to fit a polynomial function which is then used to calculate the drilling costs per kilometer at the depths of the two cases in our CO2-PENS example, 1 km and 3 km respectively for the Cold-Shallow and Hot-Deep cases (Figure S-3). The polynomial equation results in an r^2 of 0.998 and has the form:

$$y = 5.7745 \cdot 10^{-8} \cdot x^3 + 5.7573 \cdot 10^{-4} \cdot x^2 - 1.0532 \cdot x + 1204.8\,, \qquad \text{Eq. S-1}$$

where y is the drilling cost per meter ($/m) and x is the depth of the well in meters (m). The Cold-Shallow case leads to an average drilling cost of 6.25 x 10^5 $/km while the Hot-Deep case results in drilling costs of 1.56 x 10^6 $/km. Returning to the two examples, the Hot-Deep case requires 11.1 wells of 3 km each leading to total well completion costs of $55.9 x 10^6, while the Cold-Shallow case requires a mean of 59 wells of 1 km each giving a mean cost of $41.4 x 10^6. Based strictly on drilling costs, the

Cold-Shallow case becomes more attractive since the total cost is lower. However we have not yet examined the pipeline requirements or long-term maintenance costs.

Pipeline installation costs

We use data described in Middleton and Bielicki (2008) to estimate the cost of pipeline for the well field distribution network. Bielicki (2008) used 15 years of pipeline data to create an equation for estimating the cost per km of CO_2 pipeline (*PLC*) as a function of pipe diameter, *DIA* (m), pipeline length, *L* (km), and an inflation correction based on the number of years after 1990, *Y* (years), as:

$$PLC = \$1{,}686{,}630 \cdot 1.054^{\overline{Y}} \cdot \overline{DIA}^{0.9685} \cdot \overline{L}^{0.7315}, \qquad \text{Eq. S-2}$$

where the overscore indicates the non-dimensional magnitude of the quantity. We assume a pipe diameter of 2” for transport around the field, (Oldenberg et al. 2004). This equation also contains a link from the physics-based process level injection calculations because the cost of the field distribution pipeline is a function of the length of pipeline needed, which in turn is related to the number of injectors required and the size of the plume. Specifically, we divide the total plume area calculated in the injection module by the number of wells required to get an area per well for each realization. The area per well is then used to calculate a radius for each of the required wells. We then assume that each well requires two radii of pipeline to connect to the field distribution system.

Maintenance costs

The final costs we account for in the economic analysis of the injection example are maintenance costs. We consider both pipeline maintenance and wellbore maintenance costs and integrate these through the 50 year lifetime of the hypothetical project. McCoy and Rubin (2008) report estimated pipeline maintenance costs in 2004 dollars of 3250. \$/(km yr). We assume that average maintenance costs will increase at 4% per year and begin the simulation in 2008 dollars at 3800. \$/(km yr). Wellbore maintenance is assumed to be 0.15 M\$ per well in 2008 dollars (Lucier and Zobak, 2008) and allowed to increase with the same rate as used for the pipeline maintenance costs. Maintenance costs for both pipelines and wells in any given year are sampled from a normal distribution having a mean equal to the average cost for a given year with a standard deviation of 1/10 of the average cost.

Present value analysis

To create a consistent platform for comparison of the overall project costs, all cash outlays are converted to present values in the year 2008 and summed. We assume that this project will require a 10 year amortized loan with an assumed interest rate of 7.5% to cover the costs of the pipeline and wellbore completion. The initial costs are used to compute a monthly payment which is then added to the monthly payments necessary for maintenance of the wellbores and pipelines. Each total monthly charge is converted to present value using a long term average 4% discount rate and added to a running total for the present value of the entire project. At the end of the simulation, the present value of the Cold-Shallow case can then be compared directly with the present value of the Hot-Deep case, although both have much different time-history cash flow behavior.

Economic Analysis Results and Discussion

Figure S-4 shows that although the different cases have very different numbers of wells required, the drilling costs are quite similar. The Cold-Shallow case has a slightly lower total drilling cost; however, as seen in Figure S-5, the total present value of the Cold-Shallow case is much higher than the Hot-Deep case. This is due to the much greater length of pipeline required to connect the wells in the Cold-Shallow case. Figure S-6 shows that with the higher number of wells and greater pipeline length, the maintenance costs begin to dominate the total present value costs after approximately 20 years for the Cold-Shallow case. This is not true for the Hot-Deep case, where the maintenance costs stay well below the drilling costs for the entire 50 year injection period.

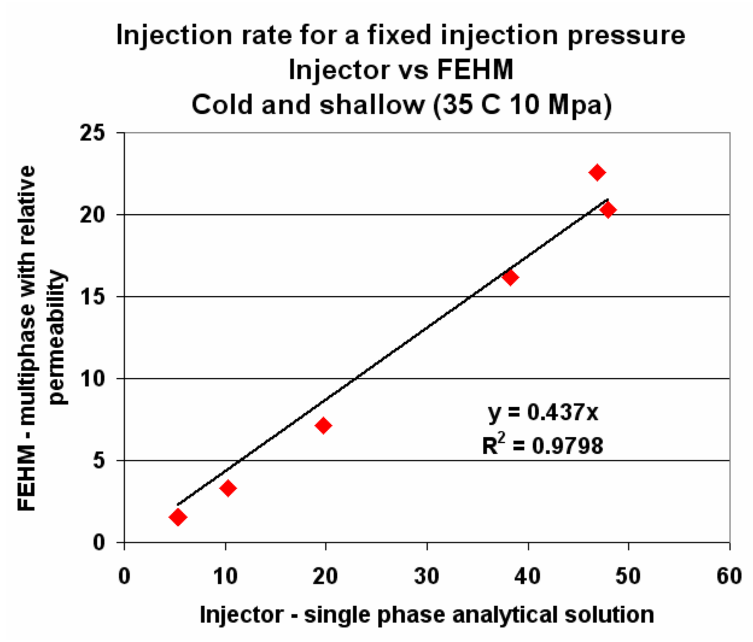
Finally, we present two examples of correlations results that can be easily obtained from the system level analysis. Figures S-7 and S-8 show the correlation between the present value cost per ton and the reservoir horizontal permeability and the present value cost per ton and the reservoir porosity respectivly. Figure S-6 shows that the two cases have much different absolute distributions of permeability and cost, however because the statistical distributions used in the two realizations, the correlation coefficient of both cases is -0.744. However, due to differences in other variables between the two cases, the importance of permeability on cost is 0.782 for the Cold-Shallow case and 0.789 for the Hot-Deep case. For porosity, the distributions span the range of sampled porosity for a wide range of costs, showing that this variable has little influence on present value cost per ton. Indeed, for both cases the importance of porosity on cost per ton is less than 0.01, and the correlation coefficient is less than -0.03. Correlation statistics are a powerful tool in deciding which variables are of greater importance in a complex, multivariable simulation, and can be used to guide data collection to better constrain output from system level models such as CO_2-PENS.

Average Depth (m)[1]	Average Cost (M$)[1]	2008 Cost Estimate[2]	2008 ($/m)
549	0.304	0.58739305	1069.932697
965	0.364	0.703325889	728.8351185
1331	0.416	0.803801016	603.9076006
1913	0.868	1.677161736	876.7181056
2636	1.975	3.816122614	1447.694467
3375	3.412	6.592714105	1953.396772
4103	5.527	10.67934668	2602.814203
4842	7.57	14.62685984	3020.830203
5629	9.414	18.18986242	3231.455396

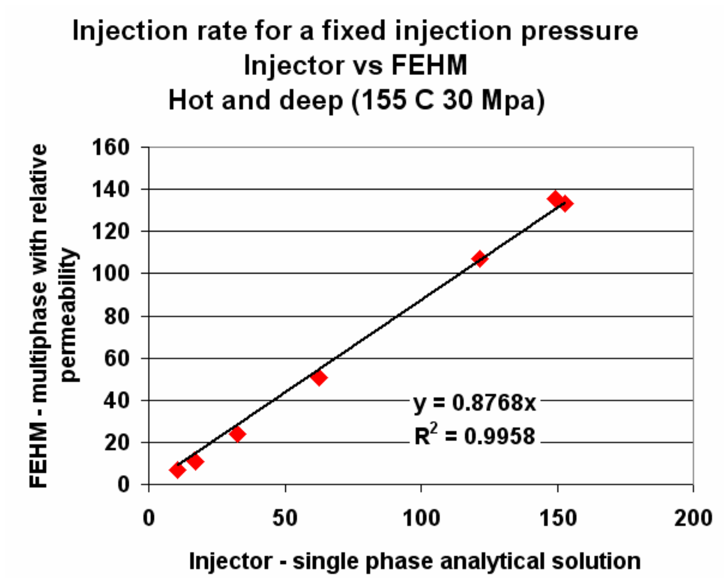
Table S-1 Drilling costs per kilometer based on JAS data for on-shore US oil wells.

[1] Data from MIT 2006 after API 2006.

[2] Cost adjusted based on 17.9% yearly increase seen from API 2006 to API 2007 drilling cost per foot data.



A



B

Figure S-1 Analytical versus numerical solutions for the A) Cold-Shallow and B) Hot-Deep cases. The tuning parameter used to generate Figure 3 in the main manuscript is the slope of the regression, also shown as the last entry on the left column on Table 1 in the main manuscript.

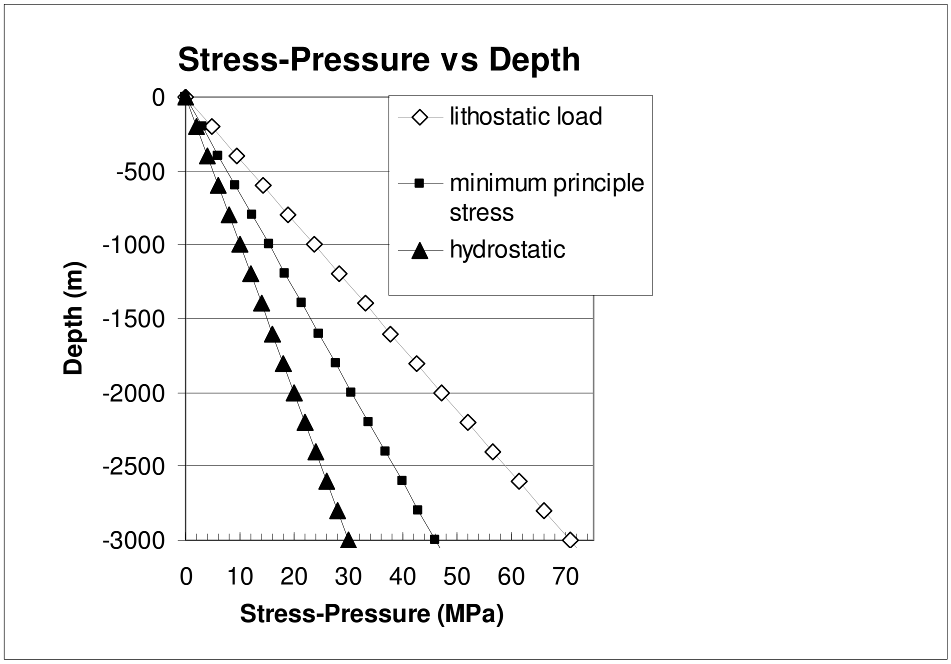


Figure S-2 Stress versus depth relationship.

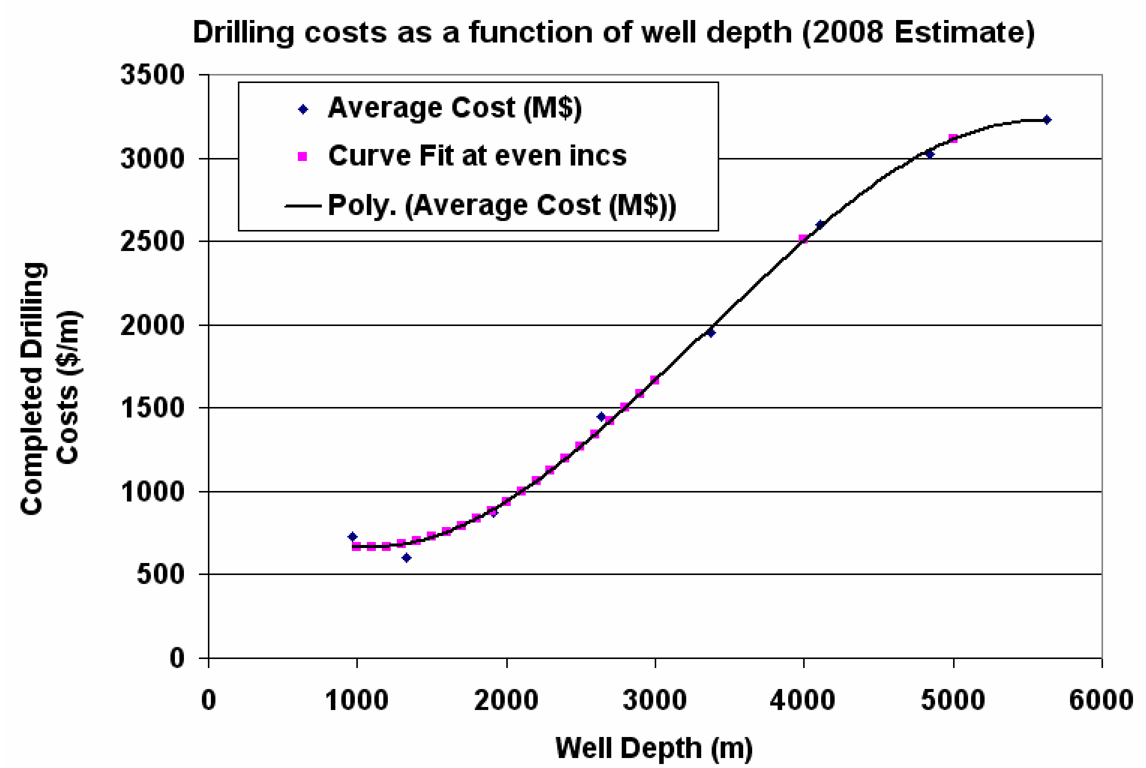


Figure S-3. Polynomial fit to the data from column 4 of Table S-1. The curve fit at even increments is plotted to show that regression we are using has enough significant figures to recapture the original fit.

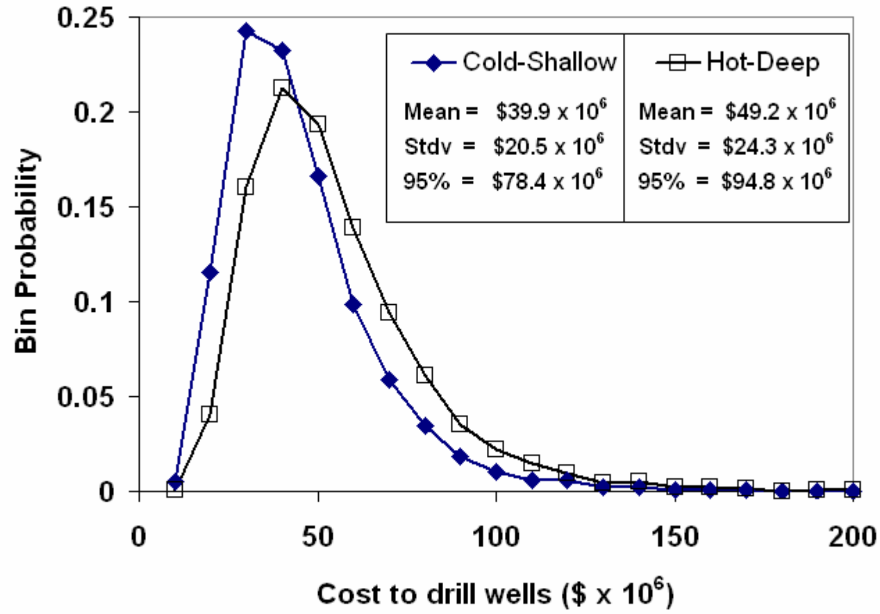


Figure S-4. Drilling costs for the two cases.

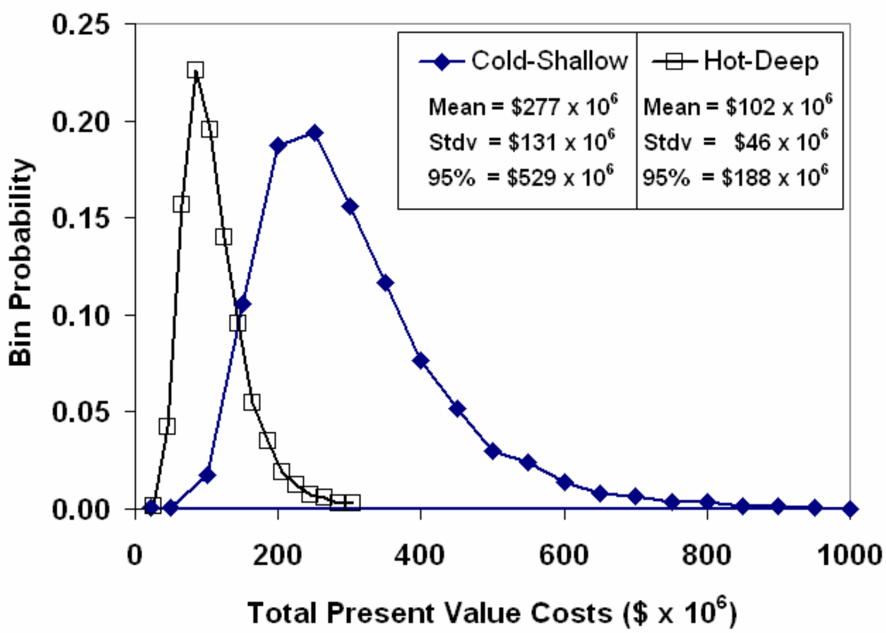
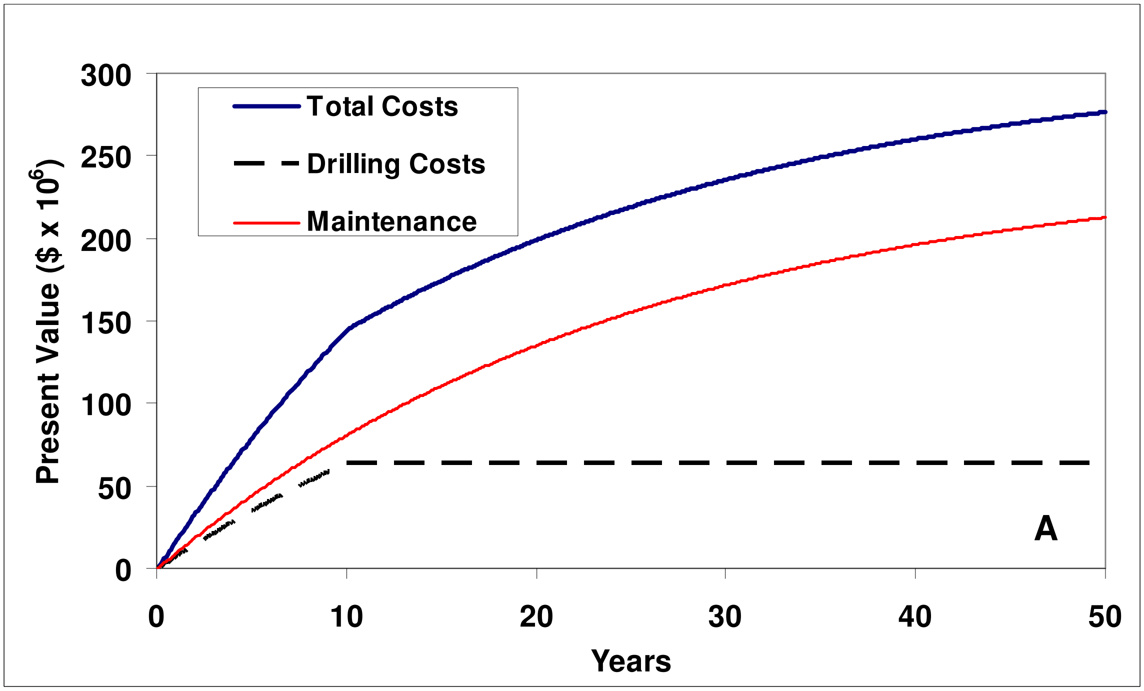


Figure S-5. Total present value costs



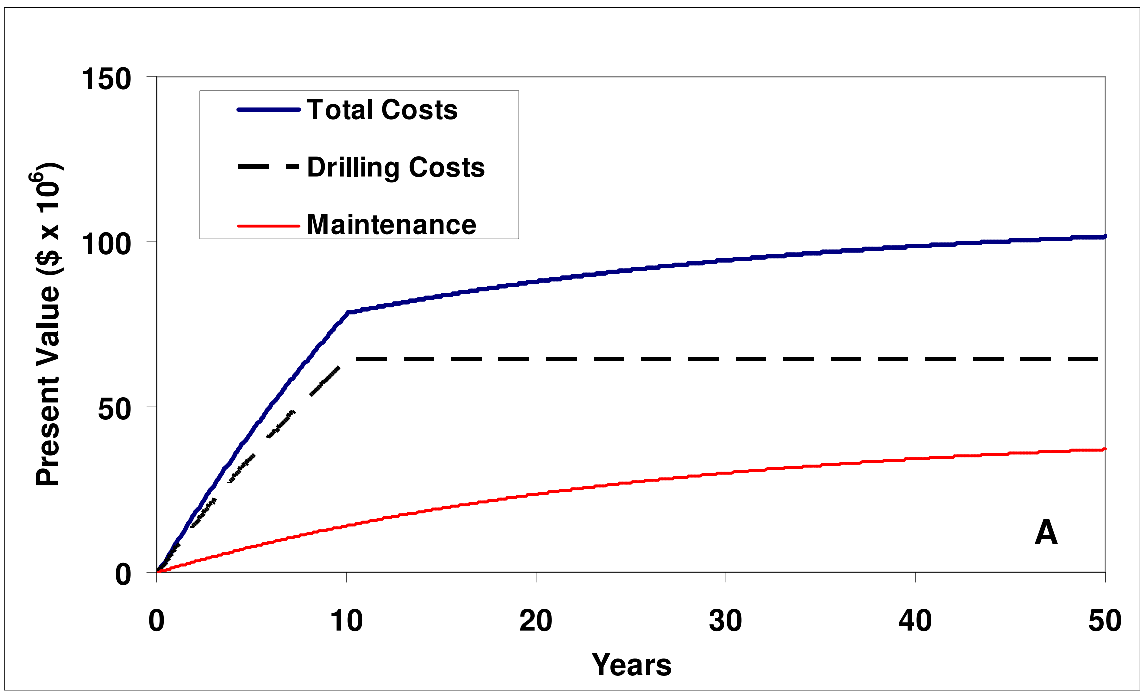


Figure S-6. Mean present value time history for A) the Cold-Shallow case and B) the Hot-Deep Case.

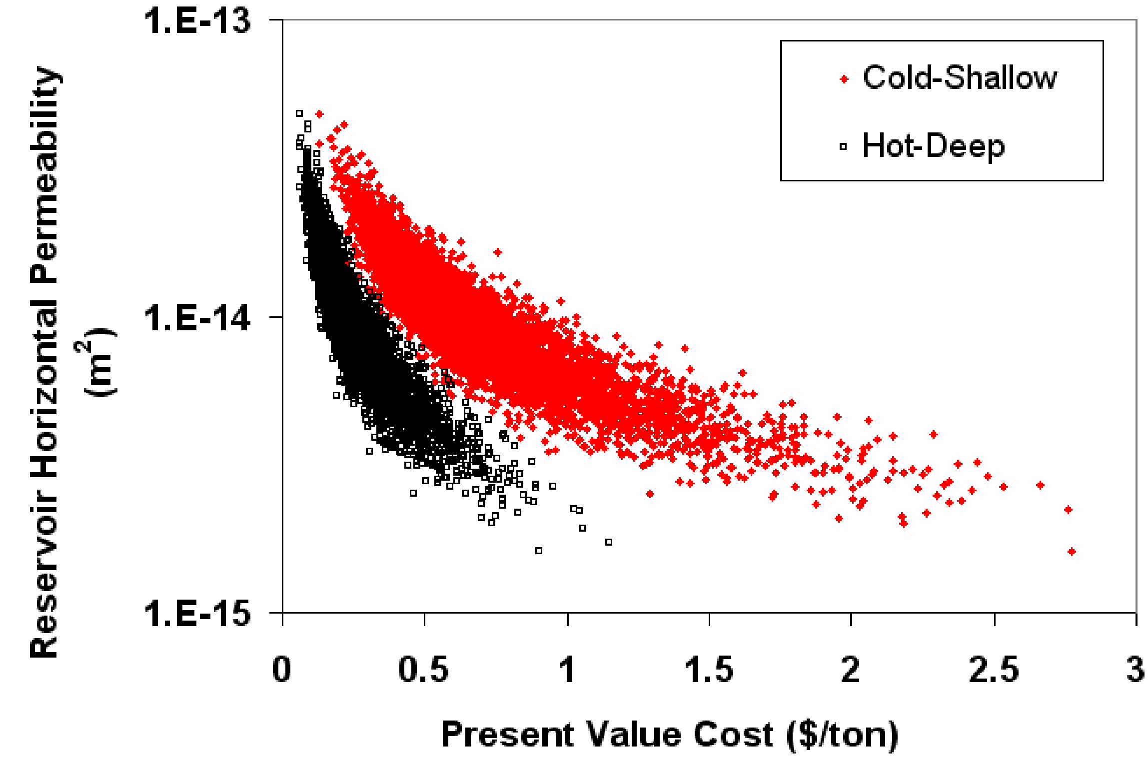


Figure S-7. Multivariate correlation plot showing correlation between PV cost per ton and the reservoir horizontal permeability.

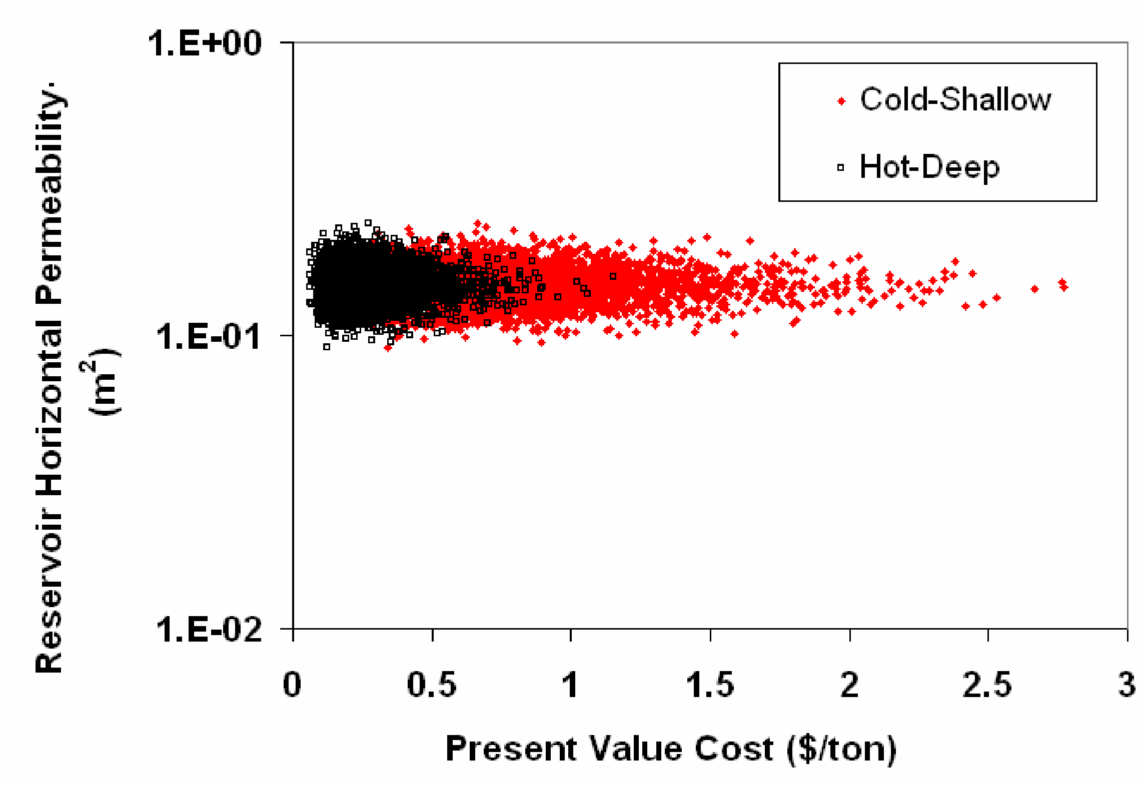


Figure S-8. Multivariate correlation plot showing correlation between PV cost per ton and the reservoir porosity.

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