NATIONAL ENERGY TECHNOLOGY LABORATORY

Study of the Use of Saline Formations for Combined Thermoelectric Power Plant Water Needs and Carbon Sequestration at a Regional Scale: Phase III Report

August 2010

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Abstract

In an effort to address the potential to scale up carbon dioxide (CO_2) capture and sequestration in the United States' saline formations, an assessment model is being developed using a national database and modeling tool. This tool builds upon the existing NatCarb database as well as supplemental geological information to address scale up potential for carbon dioxide storage within these formations. The focus of the assessment model is to specifically address the question, "Where are opportunities to couple CO_2 storage and extracted water use for existing and expanding power plants, and what are the economic impacts of these systems relative to traditional power systems?" Initial findings indicate that approximately less than 20% of all the existing complete saline formation well data points meet the working criteria for combined CO_2 storage and extracted water treatment systems.

Acknowledgements

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Acronyms and Abbreviations

atm	atmospheres
BEG	Bureau of Economic Geology
bgs	below ground surface
billion gal/yr	billion gallons per year
C	degrees Celsius
c/kWh	cents per kilowatt hour (also abbreviated as cents/kWh)
CCC	carbon capture and compression
CO_2	carbon dioxide
DEM	digital elevation model
EPEC	existing plants, emissions & capture
ft	feet
gal/MWh	gallons per megawatt hour
GIS	geographic information system
HERO	High Efficiency Reverse Osmosis
H_2O	water
hr/lb	hour per pound
hr/tonne	hours per tonne
IGCC	Integrated Gasification Combined Cycle
kg/m^3	kilograms per cubic meter
KGS	Kansas Geological Survey
lb CO_2 / MMBTU	pounds of carbon dioxide per million British Thermal Units
lb/MWh	pounds per megawatt hour
LCOE	levelized cost of electricity
MGD	million gallons per day
mi	mile
Mmt/yr	million metric tons per year
MPa/m	megapascal per meter
MW	megawatt
NatCarb	National Carbon Atlas
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
O&M	operations and maintenance
PC	pulverized coal
PDF	probability distribution function
per m	per meter
ppt	parts per thousand
psi	pounds per square inch
$scCO_2$	supercritical carbon dioxide
TDS	Total Dissolved Solids
tonnes/da	tonnes per day
tons/yr/(lb/hr)	tons per year per pound per hour
TWh/yr	terawatt hour per year
2D	two dimensional
3D	three dimensional

UTM	Universal Transverse Mercator
$US	United States' dollars
USD/yr/(tonne/hr)	United States' dollars per year per tonne per hour
VO&M	variable operations and maintenance
WECS	Water, Energy and Carbon Sequestration
yr	year

1. Introduction

This report documents advances made on the development of a national assessment modeling tool to address scale-up potential of carbon dioxide (CO_2) capture and sequestration efforts in U.S. subsurface saline formations. The Water Energy and Carbon Sequestration (WECS) model was developed to integrate the full dataset of U.S. power plants, geological saline formations, carbon capture and sequestration scenarios, and saline formation water extraction and treatment technologies. The model, developed in POWERSIM Studio™, also includes a statistical binning of saline formations based on geochemistry, depth, salinity and other important parameter profiles. These efforts build from several years' worth of research in an ongoing project consisting of three phases. Phase I of the project developed a framework and model to assess a specific source of CO_2 (San Juan generating station in northwest New Mexico) to a specific sink for the CO_2 (the Morrison formation also in northwest New Mexico) (Kobos et al., 2008). In Phase II, the project expanded to include other regions of the U.S. For example, there is substantial variability associated with different saline formations, power plant configurations, and regional constraints such as the level of existing infrastructure that will affect the overall systems' costs.

In the beginning stages of Phase III presented here, a large effort was completed to down-select a set of criteria, and refine the methodology and data assessment. A well selector tool allows the analysis to assess saline formations according to criteria for storing specific volumes of CO_2. The national-level WECS model, (WECS II) currently evaluates carbon capture and compression at any coal or natural gas-based power plant in the U.S. (sources of CO_2) and sequestration of that CO_2 in any of 325 deep saline formations in the U.S. (sinks for CO_2). The estimated parameters include distance from source to sink, costs associated with CO_2 capture, compression, transportation, and sequestration, the length of time the formation may last for a given CO_2 sequestration rate, how much water may be extracted to make additional room for the CO_2, and what the high-level costs of water treatment may be to reuse the extracted water to offset additional water demands at the power plant associated with CO_2 capture and compression. With this full analysis, multiple scenarios can be developed with custom site and sink combinations. In the coming years, the model will be used to evaluate CO_2 capture and sequestration with extracted water treatment at all currently operational coal and natural gas fired power plants in the U.S. Additionally, other sources of CO_2 can be included as desired based on custom options (e.g., hypothetical power plants using new technologies). This report describes the current state of the WECS model's development for this multi-year effort.

2. Saline Formation Database Selection Methodology

Summary Statistics for Saline Formation Data

Presented in this section are a variety of summary statistics of the saline formation data compiled from NatCarb, regional partnership data, and Texas Bureau of Economic Geology (BEG) data. The regional partnership data are limited to what was given to us to help identify the parameters that we need for the WECS II model. In some cases, additional data may reside with some of the partnerships, however it was not available in a form that could be utilized and/or was access limited to specific members of the partnerships on password protected locations on their website.

CO_2 Capacity

One of the primary data items presented by NatCarb is CO_2 capacity. This calculated value as derived by each partnership is one of the most complete as shown in the chart below (Figure 2-1). In the case of missing data, it may be possible to calculate CO_2 capacity using some of the parameters presented below. For the 16% of formations without CO_2 capacity, a determination of available data must be made to see whether capacity can be calculated or not.

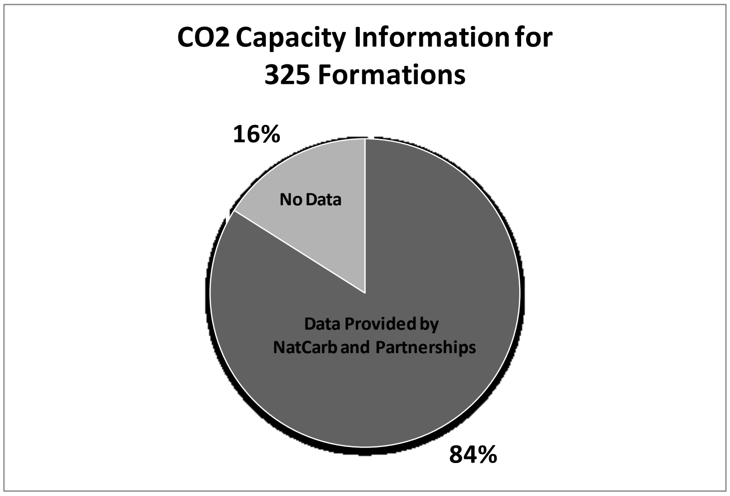


Figure 2-1. NatCarb CO_2 capacity data availability.

Depth to Top of Formation

The depth to formation data are complete for 61% of the 325 formations. This value represents the average depth below ground surface (bgs) to the top of the named formation (or basin in cases where the partnerships only defined basins). Estimates are also available for minimum, maximum and the standard deviation from the average. This information is important for determining injection depths in terms of formation suitability and determining costs. Understanding these depths will also help characterize the relationships between formation porosity, permeability, and depth which ultimately affects the amount of CO_2 that can be injected, as well as whether water can be withdrawn and of what quality.

As the distribution of data shows below, most of the average formation depths are between 3,000 and 6,000 feet (Figure 2-2). Spatially, the data that are available shows that these formations are spread across all partnership study areas. Deeper formations (from the 61% of the formations) are shown mostly in the southwest partnership area. This however is misleading as average formation depth is missing from 39% of the formations.

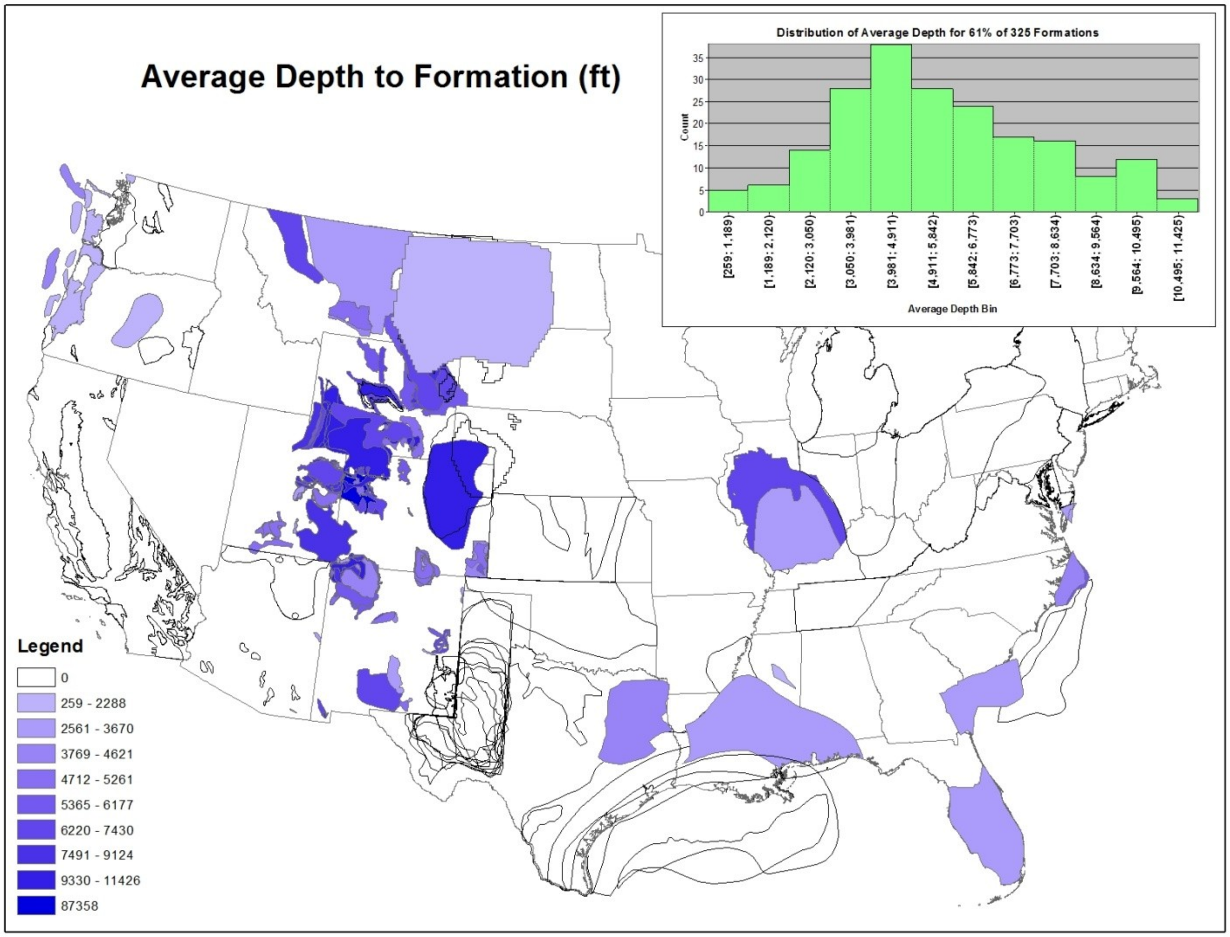


Figure 2-2. NatCarb average depth to formation data.

Formation Thickness

The formation thickness data as reported by NatCarb and the partnerships represents an average value as formation thicknesses can have a high degree of spatial variability. Estimates are also available for minimum, maximum and the standard deviation from the average. The formation thickness data are complete for 64% of the 325 formations and is reported in units of feet. This data assessment is important because it helps (along with other parameters) identify formations that may have the potential to store large amounts of CO_2 along with helping understand zones of salinity in areas where water is present.

The formation thickness represents an exponential distribution (Figure 2-3) with the thickest formations occurring on the Pacific Coast. However as stated above for average depth to formation, the histogram is misleading due to missing data for 36% of the 325 formations.

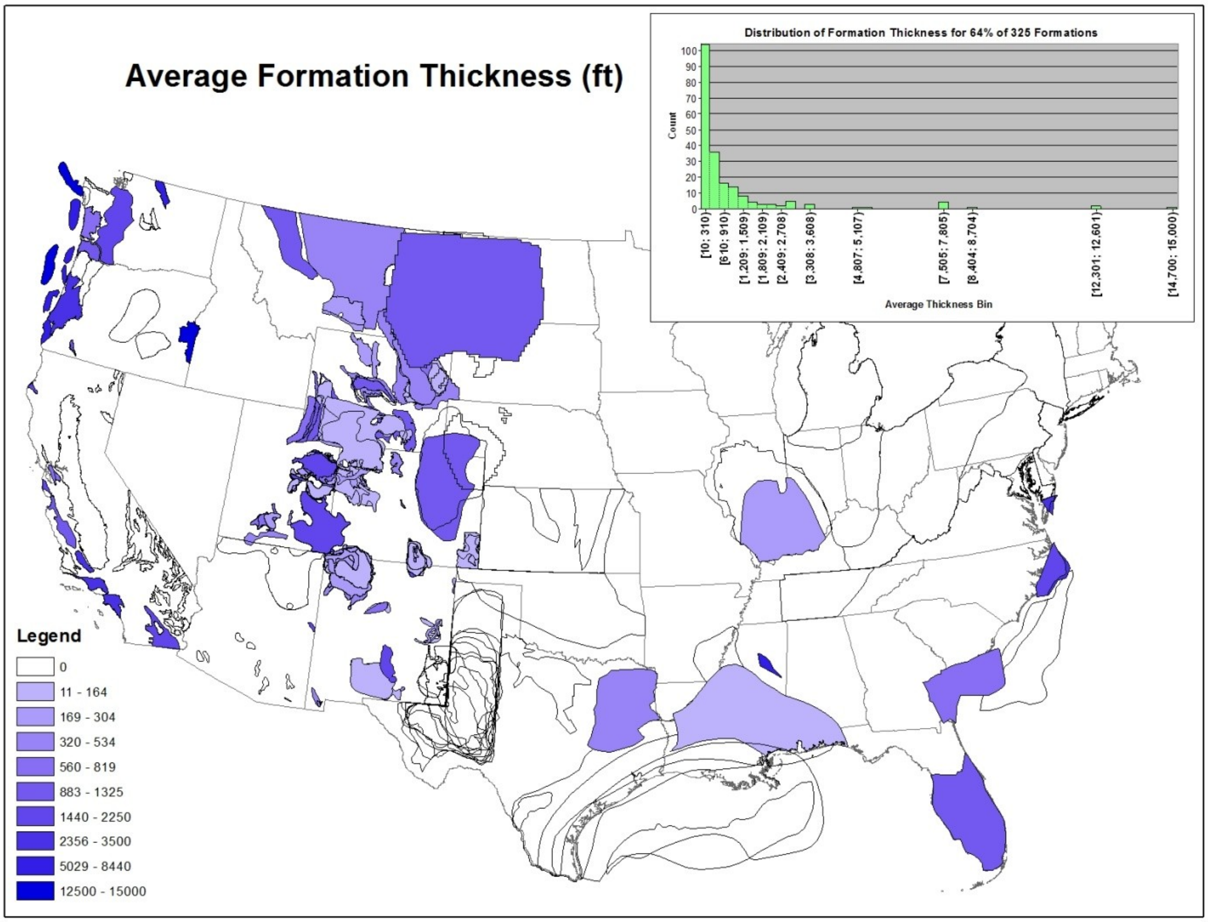


Figure 2-3. NatCarb average formation thickness data.

Porosity

Data for formation porosity was available for a little over half (53%) of the 325 formations. Figure 2-4 shows the spatial distribution of that data along with a histogram showing a somewhat normal distribution of the average data with porosities ranging from 15% to 22%. Estimates are also available for minimum, maximum and the standard deviation from the average. As stated above for average depth to formation and average formation thickness, the histogram may be misleading due to missing data for 47% of the 325 formations.

Porosity data (Figure 2-4) is used to determine the amount of CO_2 that can be stored in the formation. Another parameter in the data is pore volume, which represents the total volume of pore space in the saline formation potentially available for CO_2 storage (prior to any of the efficiency factors applied to determine the high and low CO_2 storage estimates).

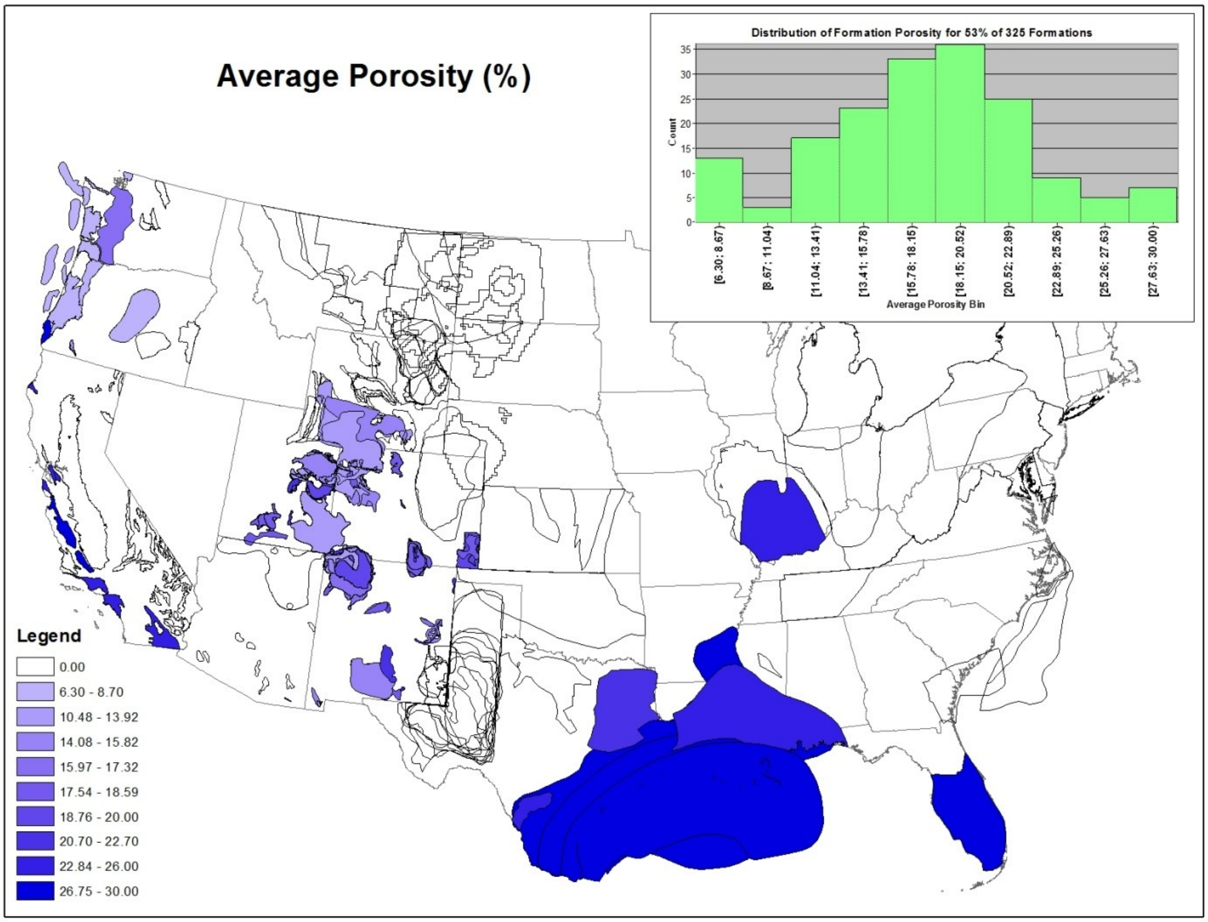


Figure 2-4. NatCarb average porosity data.

Pressure and Temperature

Average formation pressure and temperature data are available for 45% and 44% of the 325 formations, respectively. Figure 2-5 shows the distribution of pressure data. The histogram for both parameters represents a normal distribution. Estimates are also available for minimum, maximum and the standard deviation from the average. More than half of the data are missing for the formations in question so it would be difficult to pull out any meaningful spatial relationships with the distribution of the data. There is, however, a relationship between depth, pressure and temperature that may be utilized to help fill in these gaps.

Pressure and temperature data are used to determine how injected CO_2 would behave at specific depths in terms of injection rates and determining total formation capacities.

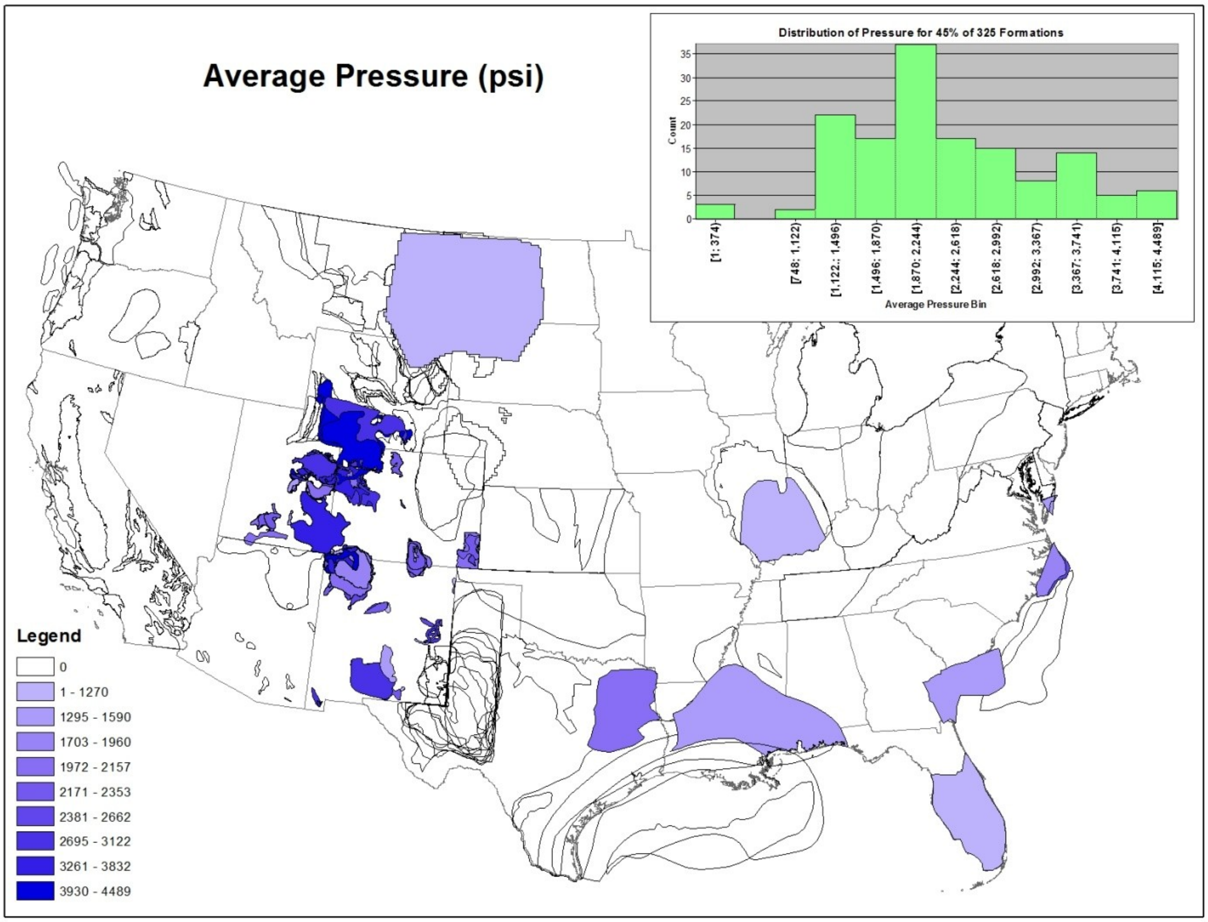


Figure 2-5. NatCarb average pressure data.

Salinity

Data for salinity are not widely reported in the NatCarb database. For the purposes of this study, the data would be difficult to use as salinities vary in different parts of a formation. In most cases the formation water becomes more saline with depth. Also for the WECS II model, there is a specific zone of salinity and depth the analysis will evaluate. For this reason, the study looked at the potential intersections of the Kansas Geological Survey (KGS) saline wells in terms of the depth to the bottom of the formation as well as the formations intersected by that well.

Intersecting Wells with 325 Saline Formations

Kobos, et al. (2010) described the initial process used to determine additional parameters for each formation based on the intersection of saline wells from the Kansas Geological Survey (KGS) well database. A more recent version of that database (KGS, 2006) was available for analysis and included primarily the same sites, plus newer sites, along with more detailed water chemistry data including cations, anions, total dissolved solids (TDS) along with well and formation characteristics.

The data are complex when looking at potential intersections. The formation ages and names in the KGS well database represent more detailed stratigraphy and age within a specific formation than the more generalized NatCarb formation data. Each partnership used versions of the KGS data, and potentially in some cases along with their own proprietary data to determine the formation characteristics. Despite the large number of salinity values in the KGS well database, salinities are not widely reported in the NatCarb saline formation database.

The goal in using this data is to understand what percentage of this data may be useful for the analysis based on desired depths and salinities. The well selector tool uses the early version of this database (Kobos et al., 2010) to be able to interactively select the data. Figures 2-6 and 2-7 show the 2006 KGS data in terms of what portion of the wells are useful for the analysis.

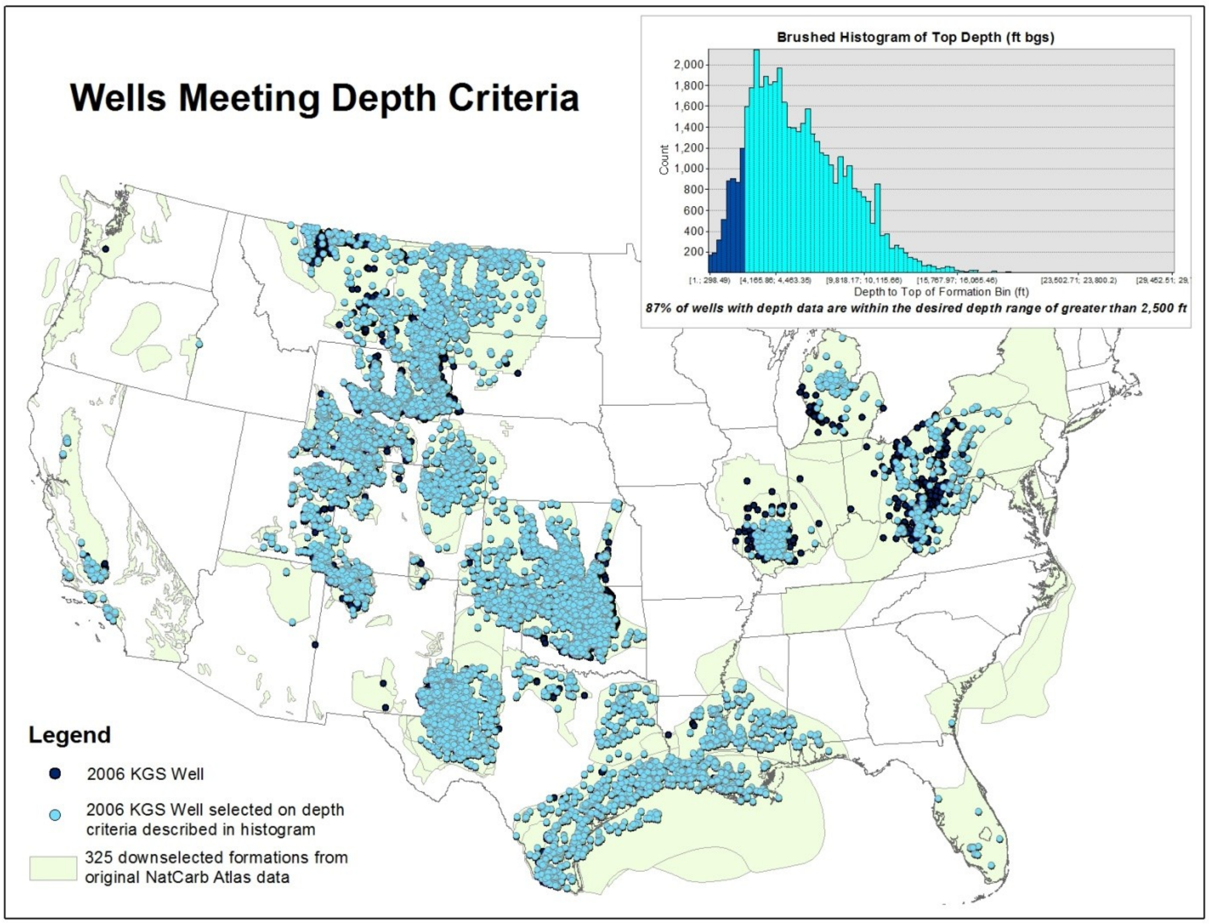


Figure 2-6. KGS wells meeting depth criteria of greater than 2,500 feet.

As shown above in Figure 2-6, 86% of the wells in the 2006 KGS database meet the WECS II model criteria as being greater than 2,500 feet. As most of these are oil and gas wells and not drinking water wells, this is to be expected. Figure 2-7 illustrates the distribution of data that meet the salinity criteria of wells with a range of 10,000–30,000 ppm. In this case, only 20% of all the well data meet this criterion.

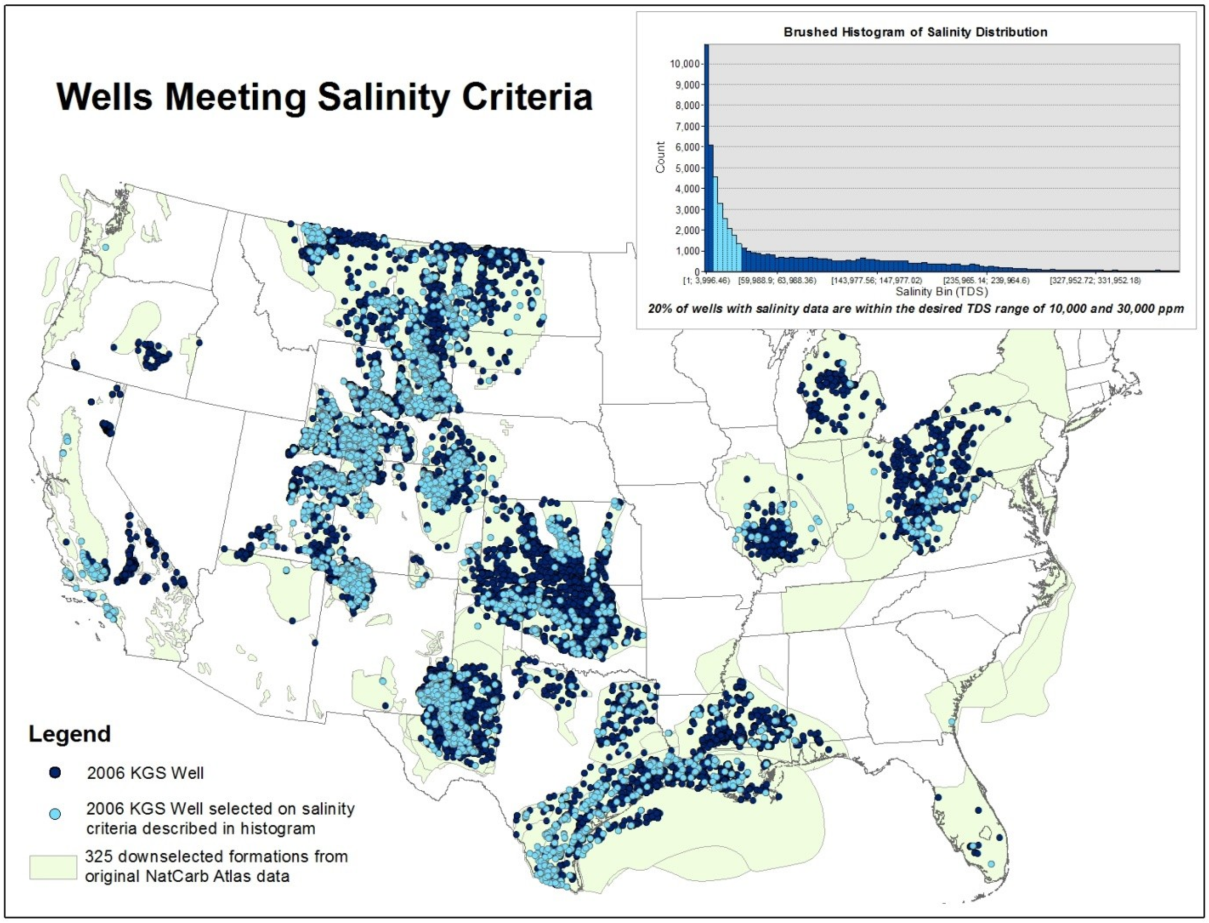


Figure 2-7. KGS wells meeting salinity criteria of 10,000–30,000 ppm.

Removing the desired depth and salinity together from this dataset reveals that only 18% of the wells in the 2006 KGS database could be utilized to help understand the salinity in the 325 formations at depths greater than 2,500 feet. This characteristic is most prevalent in formations in the intermountain west, extending into Texas and parts of the Gulf Coast. In the basins to the northeast, there are fewer wells that meet the criteria to help better understand formation salinities. Finally, this dataset will be used to develop histograms of salinity for all potentially intersecting wells. This effort is currently underway and distributions of salinity data for the 325 formations will be incorporated into a future version of the model. This data may also be incorporated in a future version of the well selector tool also described in Kobos et al. (2010).

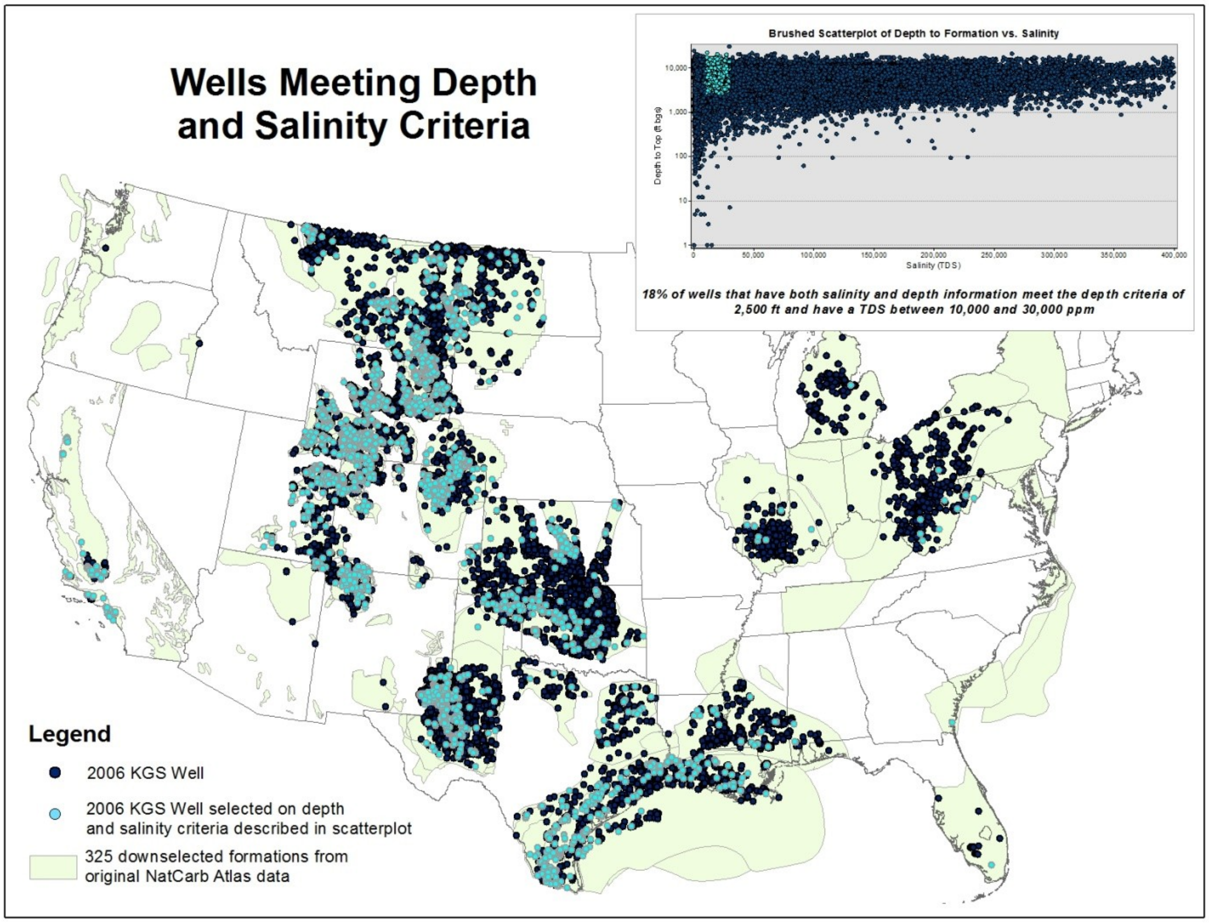


Figure 2-8. Distribution of KGS wells meeting both depth and salinity criteria.

Methods for Filling in Data Gaps

Given that many of the formation characteristics the study focuses on have partial records, an effort was made to understand any trends and correlations between these characteristics. The central idea is to use the existing data to populate fields where data are not available or does not exist.

The approach used is to group the formations into three classes: 1) formations that have depth estimates, but are missing main features like porosity, temperature and pressure, 2) formations without depth estimates, but that have a substantial number of potentially intersecting wells that may help determine average depth, and 3) formations with a majority of data missing.

Formation Class 1

Figure 2-9 shows the relationship between porosity and the top of the formation. The maximum is represented by the triangles, the minimum by squares and the average (in the middle) with diamonds. There is a relationship between top depth and porosity that is shown below with existing data, which is a function of the assumptions made by the regional partnerships or NatCarb when the data were compiled. A similar relationship exists with top of formation depth and pressure/temperature information. Formation thickness would have to be determined with a site-specific literature search. The next step will be to determine what types of uncertainty bounds or confidence intervals this data will have, or whether to have the model sample from a pre-determined distribution as a function of depth. The WECS II user will then know this dataset is estimated and may have a larger degree of uncertainty compared to what was published by NatCarb.

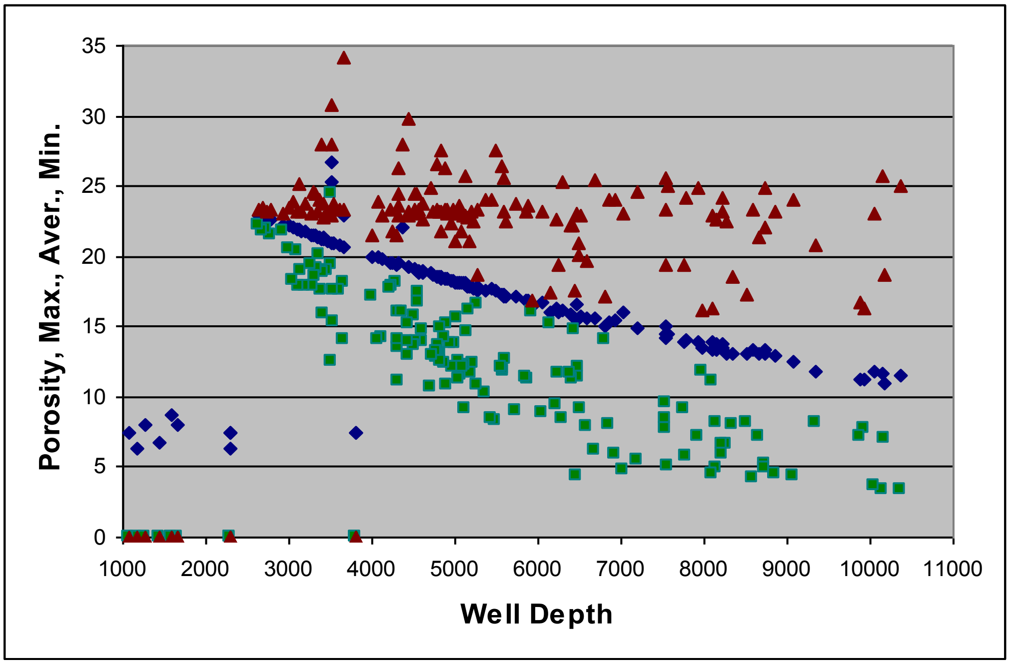


Figure 2-9. Scatterplot of porosity vs. well depth (top of formation).

Formation Class 2

To determine average depths for the formation when data are not available, one idea is to take all the intersecting wells in a formation and then look at the top of formation depths associated with the wells. The example in Figure 2-10 shows a case where there are multiple formations identified by NatCarb that 'stack' on top of each other. In other words, if a well were drilled in one location, it could potentially intersect multiple formations that have been evaluated for CO_2 storage potential. The purple plot shown on the right side of Figure 2-10 are the results of joining (using Geographic Information System (GIS) software) the 2006 KGS saline well data to one of the 325 formations. The resulting output assigns one well to each polygon, regardless if the well terminates below or above the formation in question. Only when the data are reduced to match the specific formation using the age field and understanding details about the subsurface stratigraphy can the data be reduced enough to show a more realistic range of depths associated with a particular formation. Distributions can then be created for depth, which would allow the analysis to determine other parameters like porosity, temperature and pressure. This process can be time intensive based on having to individually evaluate formations where depth to the top is missing.

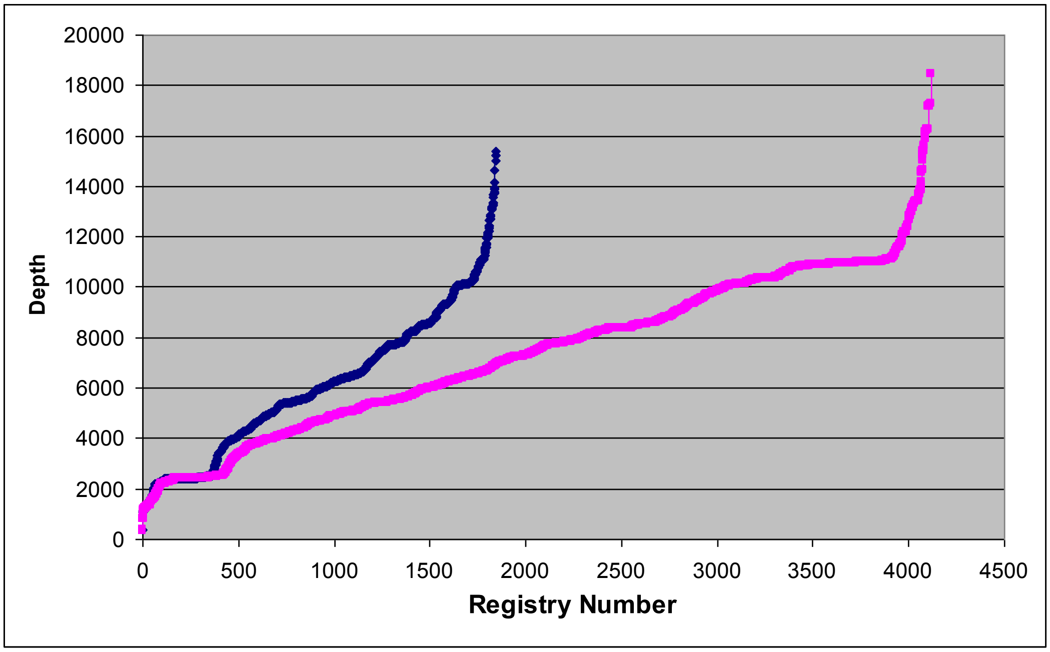


Figure 2-10. Plot of all well depths in a specific formation for all intersecting wells (right) and wells that were filtered to a specific formation that matched the same age as the formation in question (left).

Formation Class 3

These formations are missing a majority of their data and do not have more than 10 potential saline well intersections. In order to address incomplete datasets, the analysis would perform more site-specific literature searches of the data for each formation. Based on the number of missing data records that would have to be filled in, if available, the process would be time consuming and might not capture the variability and uncertainty in the data. One approach the study is considering would be to leave these formations blank but available for the user to enter data, especially if additional characterization efforts are made at future dates that would be appropriate or better estimated by a user that is more familiar with a particular formation.

3. WECS II Model Architecture and Scope

The goal of the NatCarb formation analysis described above is a statistical characterization of physical parameters associated with NatCarb polygons for use in a national scale systems level analysis of CO_2 capture from fossil fuel powered electric generators with sequestration, to saline formations and co-production of saline water for use at the power plant. The first step in that analysis was completed and involved a single source (San Juan Generating station) and one of two sinks (Morrison and Fruitland formations near the generating station). The next step is to consider any single source and any single sink from many potential sinks. The final step will be to consider the implications of multiple sources simultaneously filling multiple sinks. This progression is shown in Table 3-1. The current focus of the modeling is to refine the WECS II model.

Table 3-1. Development chart for the Water Energy and Carbon Sequestration (WECS) models.

	Specific Source (power plant)	Any Single Source	Multiple Sources
Specific Sink (saline formation)	WECS	---	---
Any Single Sink	---	WECS II	---
Mutiple Sinks	---	---	Expanding WECS II

WECS model development has been based on a bottom-up approach both from the traditional definition of energy-economic-engineering modeling, (i.e., the 'integrated assessment' model methodology), and from a pragmatic approach (e.g., begin with a single test case) then refining the analysis framework and extending it to multiple power generating stations and potential CO_2 sink locations.[i] The initial stages of the model development analyzed a single power plant relative to a single saline formation (CO_2 sink). The current model (WECS II) is able to compare any combination of a single power plant (amongst the U.S. coal and natural gas power plants) with any single saline formation in the U.S. Future work may address the capability to simultaneously compare all CO_2 sources to all saline formation CO_2 sinks through time under hypothetical carbon emission abatement scenarios.

The WECS II model is broken into 5 interrelated modules: (1) a power plant module, (2) a CO_2 capture module, (3) a carbon sequestration (geologic formations) module, (4) a water extraction module, and (5) an integrating power cost module. Generally, information is passed from the power plant module to the CO_2 capture module to the carbon sequestration module to the water extraction module, and from these modules to the power cost module. The relationships between the modules, and the key information passed between them is shown in Figure 3-1.

[i] This report draws heavily from Kobos et al., 2010 and represents the next iteration of this ongoing, multi-year project.

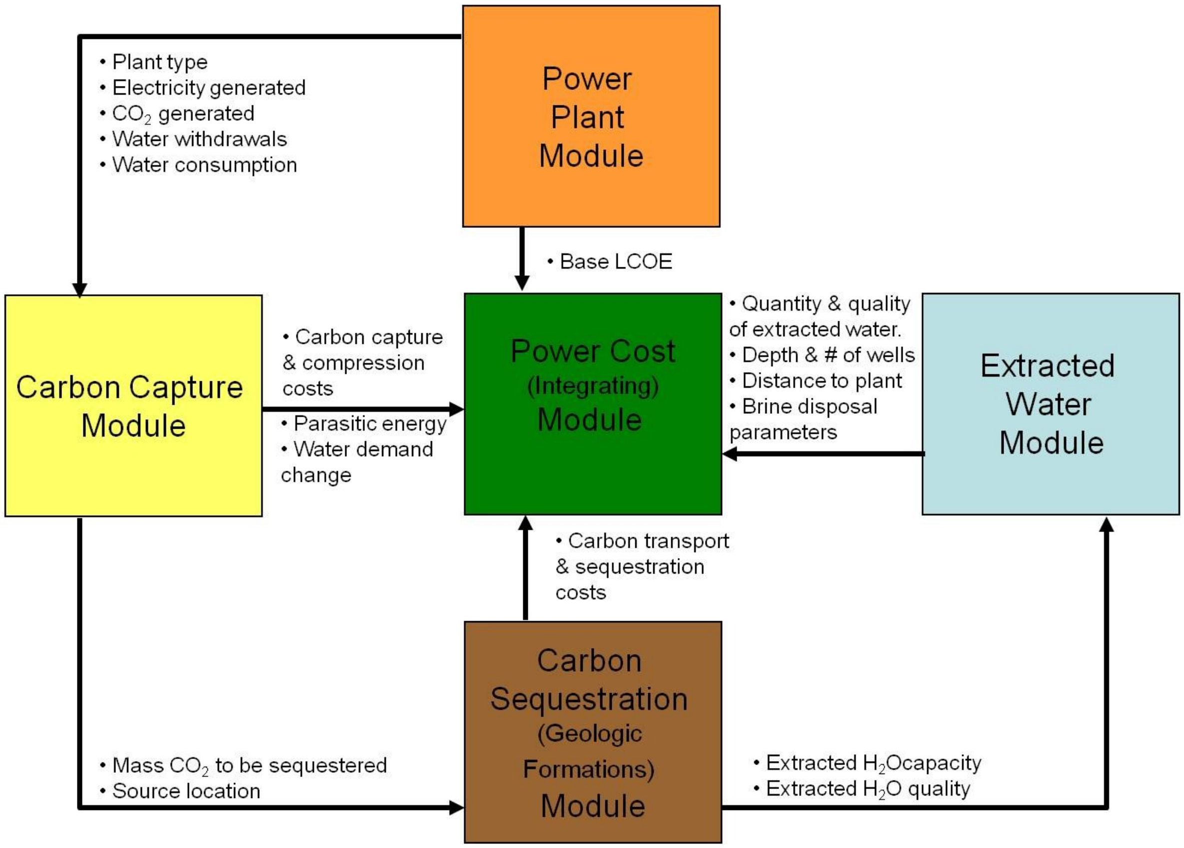


Figure 3-1. Modular structure of the WECS II model including information passed between modules.

4. Power Plant Module

The power plant module gives the model user the ability to characterize the location, size, type, and characteristics of a power plant for which carbon sequestration with associated water extraction is to be considered. From these inputs, the power plant module calculates total annual electricity generation, CO_2 production, water withdrawal demand, and water consumption.

Power Plant Module Inputs

Figure 4-1 shows the user interface options for specifying a given power plant. The input object labeled P1 in Figure 4-1 is where the model user selects the power plant type as either subcritical or supercritical pulverized coal (PC), integrated gasification combined cycle (IGCC), natural gas combined cycle (NGCC), or a natural gas turbine. The location of the plant is specified by clicking on the blue latitude and longitude numbers in input object P2, and entering the desired decimal degree location with the keyboard. The red point on the map in P2 will immediately update to show the specified location. The capacity and capacity factors can be changed with objects P3 and P4 with either the slider bars, or the associated blue text fields. Choice of power plant type in object P1 determines a default CO_2 production rate that is displayed in black in object P5. If a different CO_2 production rate is desired, a user defined value can be specified in the blue text field of object P5, and will be used by the model if the user selects the associated 'Use custom:' radio button option. In object P6 of Figure 4-1, the user can select the life of the plant. In WECS II, the plant life has impact on the financial calculations in terms of how quickly any investment in carbon capture and sequestration infrastructure must be recovered to be considered an economically-viable option. In future versions of WECS II, the plant life will become important for time based simulations of carbon capture and sequestration by multiple plants to multiple sinks.

In object P7 of the power plant module interface inputs shown in Figure 4-1, the user can choose between once through cooling, cooling towers, cooling ponds, and dry cooling technologies for the power plant cooling requirements. The selected cooling technology and power plant type result in default water withdrawal and consumption rates as shown in black text in object P8 of Figure 4-1. Finally, object P9 uses the selected power plant and cooling technologies to suggest a default base levelized cost of electricity (LCOE) for the plant broken down into fuel costs, cooling, and other costs. As with objects P5 and P8, the user can input a custom LCOE by selecting the appropriate radio button and changing the component LCOE values in blue text as desired. This includes specifying the reference year for display of the default costs (and all other costs in the model) as well as the reference year associated with the custom cost input values. The model equates dollar amounts from different reference years by using the United States Gross Domestic Product Chained Price Index.

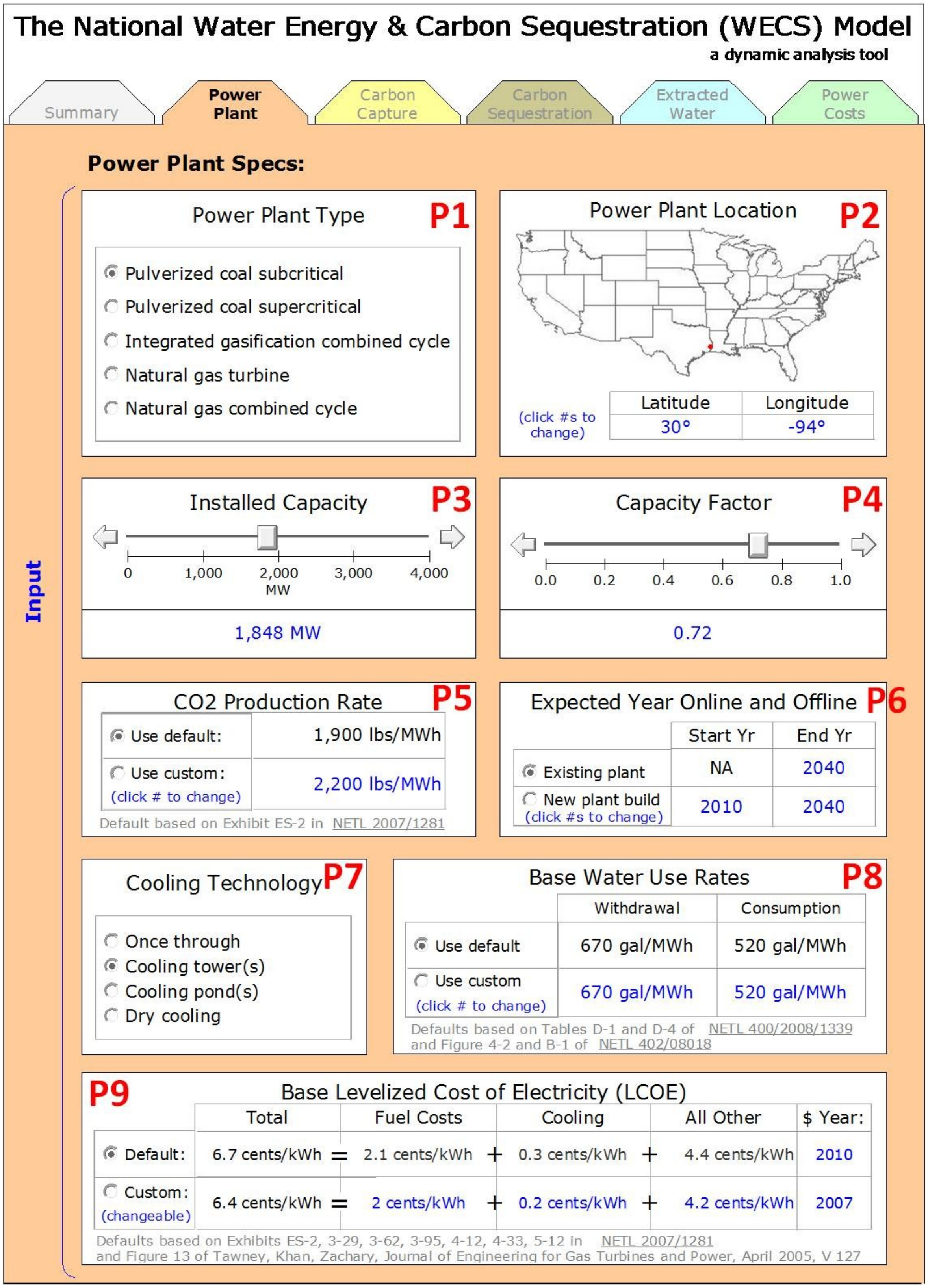


Figure 4-1. User interface inputs to WECS II power plant module.
Note: Values in blue and radio buttons or slider bars can be changed by the user. The numbers in red are superimposed here to help with the description of the input options.

For any power plant and cooling type combination, the model suggests literature-based defaults for CO_2 production rate, water withdrawal and consumption rates, and LCOE values, all of which can be overridden by a user with more information or a user interested in testing different plant behaviors. This pattern of data based parameter defaults with a user defined option is used throughout the WECS II model to provide best available defaults with flexibility to enter a custom value. The defaults for the power plant module are based on data contained in several NETL (2007a, 2008, 2009b) and Tawney et al. (2005) reports characterizing aspects of power plant operations, and are explained in further detail in the next three subsections. The default CO_2 production rates, default water use rates and default LCOE values are discussed in the following sections.

Carbon Dioxide Production Rate

The base case CO_2 production rate is selected by the model depending on the type of power plant under consideration. The default CO_2 production rates for each type of power plant used by the model are shown in Table 4-1. Except for the gas turbine, values in Table 4-1 are from Exhibit ES-2 of NETL (2007a), rounded to the nearest 100 pounds of CO_2 per megawatt hour (lb/MWh). For the IGCC, the value used is the rounded average of all 3 brands. For the gas turbine, a value of 1000 lb/MWh is assumed. Where additional information is available, user input can supersede the default values.

Table 4-1. Default CO_2 production rates utilized by the WECS II power plant module.

Power plant type	Default CO_2 Production Rate [lb/MWh]	Data Source
Pulverized Coal: Subcritical	**1900**	**NETL (2007a) Report**
Pulverized Coal: Supercritical	**1800**	**NETL (2007a) Report**
Integrated Gas Combined Cycle (IGCC)	**1700**	**NETL (2007a) Report**
Natural Gas Turbine	**1000**	**Assumption**
Natural Gas Combined Cycle	**800**	**NETL (2007a) Report**

Cooling Technology

The base case also specifies the cooling technology in the power plant module using cooling towers and the option to choose once through, cooling ponds, or dry cooling. While a gas turbine does not need a cooling system, the other four plant types do. Therefore, the model must be able to incorporate four plant types, times four cooling types plus the gas turbine plants, or a total of seventeen different plant configurations. For each of these configurations, baseline water withdrawal and consumption rates and LCOE are needed. As with CO_2 production rate, the model default values may be overridden by the user if they have specific information or want to evaluate the impact of different values.

Gas turbines were assumed to have negligible water requirements. To estimate default water withdrawal and consumption rates for each of the other 16 potential plant configurations, NETL (2008) report values were employed. Table D-1 and D-4 in that report which contain estimated water withdrawal factors for a large number of power plant configurations were used as the starting point for NGCC with all cooling types, PC plants with once through, tower, or pond cooling systems, and IGCC plants with tower cooling. Wet flue gas desulfurization (FGD) was assumed for the PC plants. Figures 4-2 and B-1 in NETL (2009b) were used to estimate dry cooling requirements for PC and IGCC plant types by taking the water requirements for processes besides cooling. The dry-fed IGCC plant types were assumed for the IGCC plants. Water usage by an IGCC plant with once through or cooling pond systems was not available in either report, and was estimated by interpolation between the PC supercritical and NGCC values for once through and cooling pond cooling as compared to the relationship of all three technologies for tower cooling. The model default values are shown in Table 4-2.

There are several values shown in Table 4-2 that may be the result of small sample sizes or non-representative locations or operating conditions. Specifically, the consumptive use value of 64 gallons per MWh for supercritical pulverized coal power plants with cooling ponds may appear low relative to those of other technologies. This amount is around half the consumption for the same plant type cooled with once through technology (124 gal/MWh), and on the order of the consumption for the same plant type using dry cooling technology (59 gal/MWh). The seemingly low value, and the fact that only five data points were used to derive it suggest that it may not be widely representative (NETL, 2008). The relative magnitude of the water use values associated with pulverized coal plants with cooling towers require further explanation. For both withdrawal and consumption, more water is used by the supercritical plant per energy produced than by the subcritical plant. This is contrary to expectations for withdrawals at least as stated in the same NETL report (2008, p. 21); "A supercritical boiler is more efficient and therefore requires less cooling water flow than a subcritical boiler for an equivalent amount of electrical generation output." Thus, it is suggested the WECS II model defaults are used with the understanding they are taken from select literature-based sources, and where more specific information is available, it should be incorporated by using the custom input capability of the WECS II model.

Table 4-2. Model default water withdrawal and consumption rates for different power plant and cooling technologies.

Model Default Base Plant Water Use					
Withdrawal		Base H_2O withdrawal [gal/MWh]			
	Plant Type	Once Through	Tower	Cooling Pond	Dry
	PC Sub	27113	531	17927	76
	PC Super	22611	669	15057	67
	IGCC	**11002**	226	**7284**	57
	NGCC	9010	150	5950	4
Consumption		Base H_2O consumption [gal/MWh]			
	Plant Type	Once Through	Tower	Cooling Pond	Dry
	PC Sub	138	462	804	68
	PC Super	124	518	64	59
	IGCC	**32**	173	**220**	53
	NGCC	20	130	240	4
Data	Dry cooling values for PC and IGCC taken from non cooling term in Figures 4-2 and B-1 of NETL 402/080108 (2009b). IGCC once-through and cooling pond values (in blue) are interpolated based on surrounding values. All other values are from Tables D-1 and D-4 in NETL-400/2008/1339 (2008).				

Levelized Cost of Energy

The LCOE estimates for new PC, IGCC, and NGCC plants with tower cooling are provided in Exhibit ES-2 of NETL (2007a). These values are shown in Column A of Table 4-3. The IGCC value is an average of three IGCC systems considered in the NETL (2007a) report.[ii] Additional costs associated with the cooling system were estimated by assuming 10% of fixed costs (labor) and 100% of water costs (variable operating cost) are associated with the cooling system. Finally, the capital, fixed, and variable costs associated with the cooling system were totaled and adjusted (levelized) into the portion of LCOE attributable to the cooling system. The percent of LCOE estimated to be a result of the cooling system is shown in Column B of Table 4-3.

[ii]Exhibits 3-29, 3-62, 3-95, 4-12, 4-33, and 5-12 in the same report itemize total capital costs in such a way that the cooling system capital cost can be isolated. Exhibits 3-31, 3-64, 3-97, 4-14, 4-35, and 5-14 show variable, fixed, and fuel-based operating costs.

Table 4-3. Power Generating Station Cost and Cooling System Components.
Note: Columns A and B are based on data in NETL (2007a) report 2007/1281 Exhibits ES-2, 3-29, 3-62, 3-95, 4-12, 4-33, and 5-12. Factors 0.64 and 2.7 represent relative costs of once-through and dry cooling systems respectively compared to tower cooling as reported in Figure 13 of Tawney et al. (2005). The calculations in columns C-F use columns A and B and the Tawney et al. (2005) relative cooling cost factors.

Column ID	(A)	(B)	(C)	(D)	(E)	(F)
Method	NETL (2007a) report 2007/1281		A*B	C*0.64	C*2.7	A-C
Plant Type	LCOE (c/kWh)	% Plant Cost From Cooling System	Cost of tower cooling (c/kWh)	Cost of once-through cooling (c/kWh)	Cost of dry cooling (c/kWh)	Cost w/o cooling (c/kWh)
PC Sub - Cooling Tower	6.4	3.7%	0.24	0.15	0.64	6.16
PC Super - Cooling Tower	6.3	3.7%	0.23	0.15	0.62	6.07
IGCC - Cooling Tower	7.8	2.8%	0.22	0.14	0.59	7.58
NGCC - Cooling Tower	6.8	1.5%	0.10	0.06	0.27	6.70

Next, the relative costs for once through and dry cooling compared to tower cooling were adapted from a report by Tawney et al. (2005). Tawney et al. (2005) reports multiplicative factors of 0.64 and 2.7 for the relative costs of once-through and dry cooling systems respectively compared to tower cooling.[iii] Finally, the LCOE exclusive of the cooling costs was estimated by subtracting the estimated cost of tower cooling in Column C of Table 4-3 from the total LCOE in Column A of Table 4-3. Results are shown in Column F of Table 4-3.

No information on the relative costs of cooling pond systems was found, so it was assumed that cooling pond systems would have a cost similar to once-through systems. Gas turbine systems were assumed to have a LCOE of 10 cents per kilowatt-hour (c/kWh) and no cooling system. These assumptions, along with the information in Table 4-3 were sufficient to estimate a default LCOE for each plant configuration considered by the model as summarized in Table 4-4.

[iii] These factors were multiplied by the estimates of levelized cost of tower cooling in Column C of Table 4-3 to get estimates of the levelized cost of once through and dry cooling as seen in Columns D and E of Table 4-3.

Table 4-4. Default LCOE values used by the model (2007 $US).

LCOE (c/kWh)				
Plant Type	Once Through	Tower	Cooling Pond	Dry
PC Sub	6.3	6.4	6.3	6.8
PC Super	6.2	6.3	6.2	6.7
IGCC	7.7	7.8	7.7	8.2
Gas Turbine	10	10	10	10
NGCC	6.8	6.8	6.8	7.0

The default water use and LCOE values described here are intended only to be reasonable averages for a given plant type and cooling system. While many studies throughout the research community report a wide range of values associated with each of these parameters, the model has been developed to incorporate either the default values reported here, or a custom value entered by the model user.

Power Plant Module Outputs

From the inputs described above, the power plant module calculates total annual electricity generation, CO_2 production, water withdrawal demand, and water consumption, and energy production costs. These values are passed to other modules as shown in Figure 3-1**Error! Reference source not found.**, and are also displayed in the interface as shown in Figure 4-2. In addition to absolute values associated with the main module outputs, the interface also compares the electricity generation, capacity, capacity factor, and emission rates to all other power plants using coal or gas in operation in the United States in 2005 as reported in eGRID2007 (2007). All values shown in Figure 4-2 update instantly to changes made within the model's inputs.

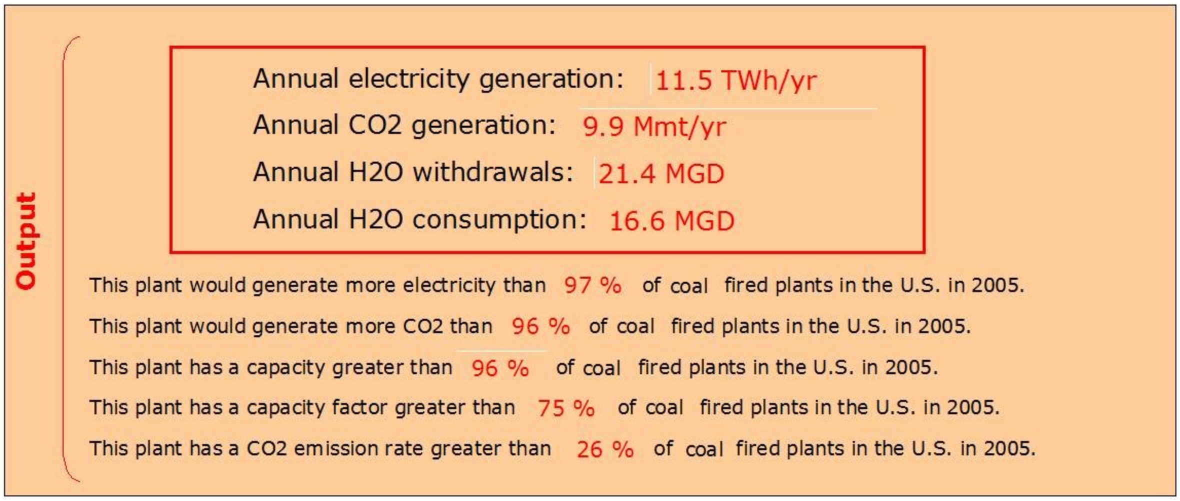


Figure 4-2. User interface outputs from WECS II power plant module.
Note: Includes electricity generation in terawatt hours per year (TWh/yr), CO_2 generation in millions of metric tonnes per year (Mmt/yr), and water withdrawals and consumption in millions of gallons per day (MGD), and how plant properties compare to the suite of power plants operating in 2005.

5. Carbon Capture Model

Once a power plant has been specified in the power plant module, the percentage of CO_2 to be captured from the plant, the energy and water consequences of that capture, and the characteristics of makeup power are calculated in the CO_2 capture module.

Carbon Capture Module Inputs

Figure 5-1 shows the user interface for changes in inputs to the CO_2 capture module of the WECS II model. The key input value is the percent of CO_2 to be captured, which can be changed with the slider bar or blue text field in the object labeled C1 in Figure 5-1. Once this percentage has been chosen, the model selects an associated parasitic energy requirement from a set of curves relating % CO_2 capture to parasitic energy requirements by power plant type as seen in the object labeled C2 in Figure 5-1. The dashed line in the graph specifies the default relationship. The default passes through the red crosses for pulverized coal plants, and of the same relative shape but passing through the purple or orange cross for NGCC and IGCC plants, respectively. If the model user has a different relationship between the percentage of CO_2 capture to resulting parasitic energy requirements, they can check the 'use custom' check box in the legend of the graph (which will uncheck the 'use defaults' check box above it), and then the blue solid line on the graph is the relationship used by the model. The blue solid line can be adjusted by clicking on it once to see the points that describe it corresponding to 0%, 30%, 50%, 70%, 90%, and 100% CO_2 capture. These points can then be moved up and down until the desired relationship is shown. With the information determined in objects C1 and C2 of Figure 5-1, the model now has the parasitic energy requirements associated with CO_2 capture and compression as a percentage of the energy production of the power plant specified in the power plant module.

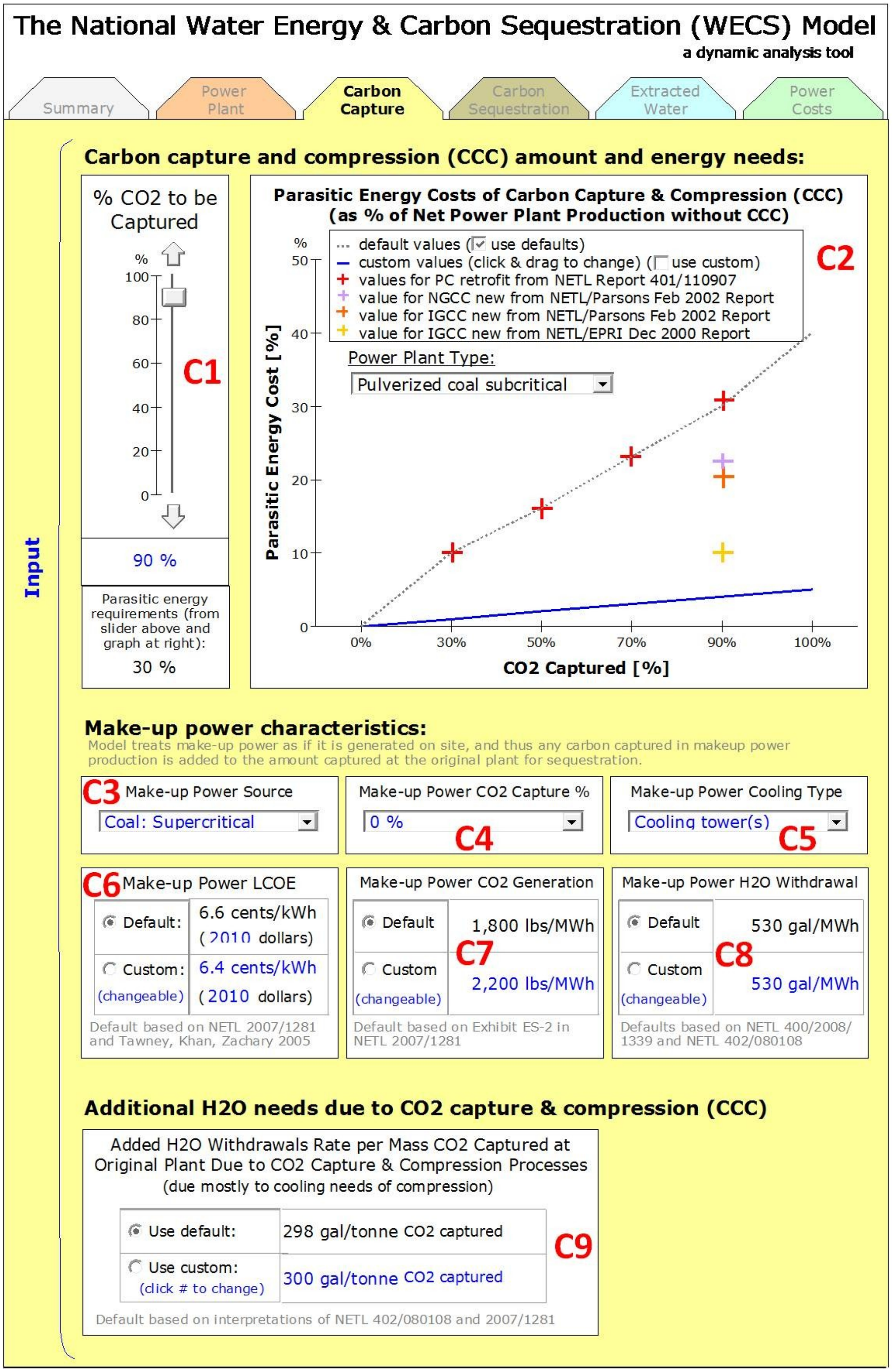


Figure 5-1. User interface inputs to WECS II carbon capture module.
Note: Values in blue and radio buttons or slider bars can be changed by the user. The numbers in red are superimposed here to help with the description of the input options.

The WECS II model requires make-up power to offset the parasitic losses associated with CO_2 capture and compression at the original power plant. The make-up power is assumed to come from a new power plant located close to the original power plant. In the objects labeled C3 through C5 in Figure 5-1, the model user can choose the type of make-up power plant utilized, what percentage of CO_2 is captured at the make-up plant, and the cooling technology used by the make-up plant. The make-up power plant type determines a default CO_2 generation rate for object C7. Selection of this default rate follows the same logic as described previously for the original plant. The make-up power source, cooling type, and rate of CO_2 capture all determine a default LCOE and water withdrawal requirement for objects C6 and C8, respectively. Selection of these defaults follows the same logic as described previously for the original plant. A model user can specify the desired value by selecting the appropriate radio button and changing the blue text in objects C6 through C8. It should be noted that for new power plants, the notion of makeup power is not applicable. In these cases the cost, CO_2 generation rates, and water requirements can be set to zero in objects C6 through C8, and all power plant characteristics for the new power plant with sequestration capabilities can be defined in the power plant module.

In addition to water demand associated with makeup power, CO_2 capture and compression also requires additional water supplies at the original power plant. This 'process' water is largely a result of additional cooling demands due to compression of the captured CO_2, and is specified by the user in object C9 of Figure 5-1.

Default Values for Parasitic Energy Requirements of Carbon Capture and Compression

The value curves for parasitic energy requirements all go through the origin (0% parasitic energy needs for 0% CO_2 capture) and have a relative shape determined by values for 30%, 50%, 70%, and 90% capture for a pulverized coal plant published in NETL (2007b). They are also scaled according to values for 90% capture for NGCC, IGCC, and gas turbine plants. Carbon Dioxide capture technology is monoethanolamine based for all power plants except IGCC which assumes a Selexol process. The parasitic energy requirements for 90% CO_2 capture in NGCC and IGCC plants are based on values published in NETL/CTC (2002). Table 5-1 shows the default parasitic energy penalties used by the model for 30%, 50%, 70%, 90%, and 100% CO_2 capture, based on published reports and transparent assumptions. As in the power plant module within the larger WECS II model, user input can also override any of the default values in the CO_2 capture module.

Table 5-1. Default parasitic energy penalties associated with percentage of CO_2 capture as a function of power plant type.

	% Carbon Captured and Compressed				
Plant Type	**30%**	**50%**	**70%**	**90%**	**100%**
PC Sub	10%	16%	23%	30%	40%
PC Super	10%	16%	23%	30%	40%
IGCC	6%	11%	15%	20%	27%
Gas Turbine	8%	14%	19%	25%	34%
NGCC	7%	12%	17%	22%	29%

Default Values for Process Water Requirements

Marginal demand and marginal water use per mass CO_2 captured were calculated based on carbon emission and water use for CO_2 capture values reported by NETL (2007a) and Appendix B in NETL (2009b), respectively. These calculations and the resulting default values for marginal water use due to CO_2 capture and compression are shown in Table 5-2. Values assume the use of cooling towers. Scenarios where the additional cooling load is to be met by other cooling technologies would have to be implemented by using the custom user input option in object C9.

In Table 5-2, Column A values in bold are from NETL (2007a), column B values are from subtracting the values reported in Appendix B of NETL (2009b). Values for gas turbine for both column A and column B are assumed based on the NGCC values. Column C values are from dividing column B by 90% of column A and converting to tonnes.

Table 5-2. Default marginal water withdrawal values per mass of CO_2 captured by power plant type.

	Column ID	A	B	C
	Column Name	CO_2 Emissions	Marginal H_2O withdrawal for 90% CO_2 capture	Marginal H_2O withdrawal per tonne CO_2 captured
	Unit	[lb CO_2/MMBTU]	[gal/MMBTU]	[gal/tonne CO_2]
	Method	NETL (2007a) 2007/1281	NETL (2009) report 402/080108	2204.6*B/(0.9A)
Plant Type	PC Sub	**203**	**24.7**	298
	PC Super	**203**	**24.4**	294
	IGCC	**200**	**9.55**	117
	Gas Turbine	140	22.1	387
	NGCC	**119**	**22.1**	455

Carbon Capture Module Outputs

Once all user inputs have been selected, the carbon capture module calculates the marginal water demand, and the total amount of CO_2 captured and compressed at the original and makeup power plants. The total amount of compressed CO_2, along with the power plant location is then passed to the carbon sequestration module as shown in Figure 5-1. The carbon capture module also displays various results in the graphic user interface as shown in Figure 5-2.

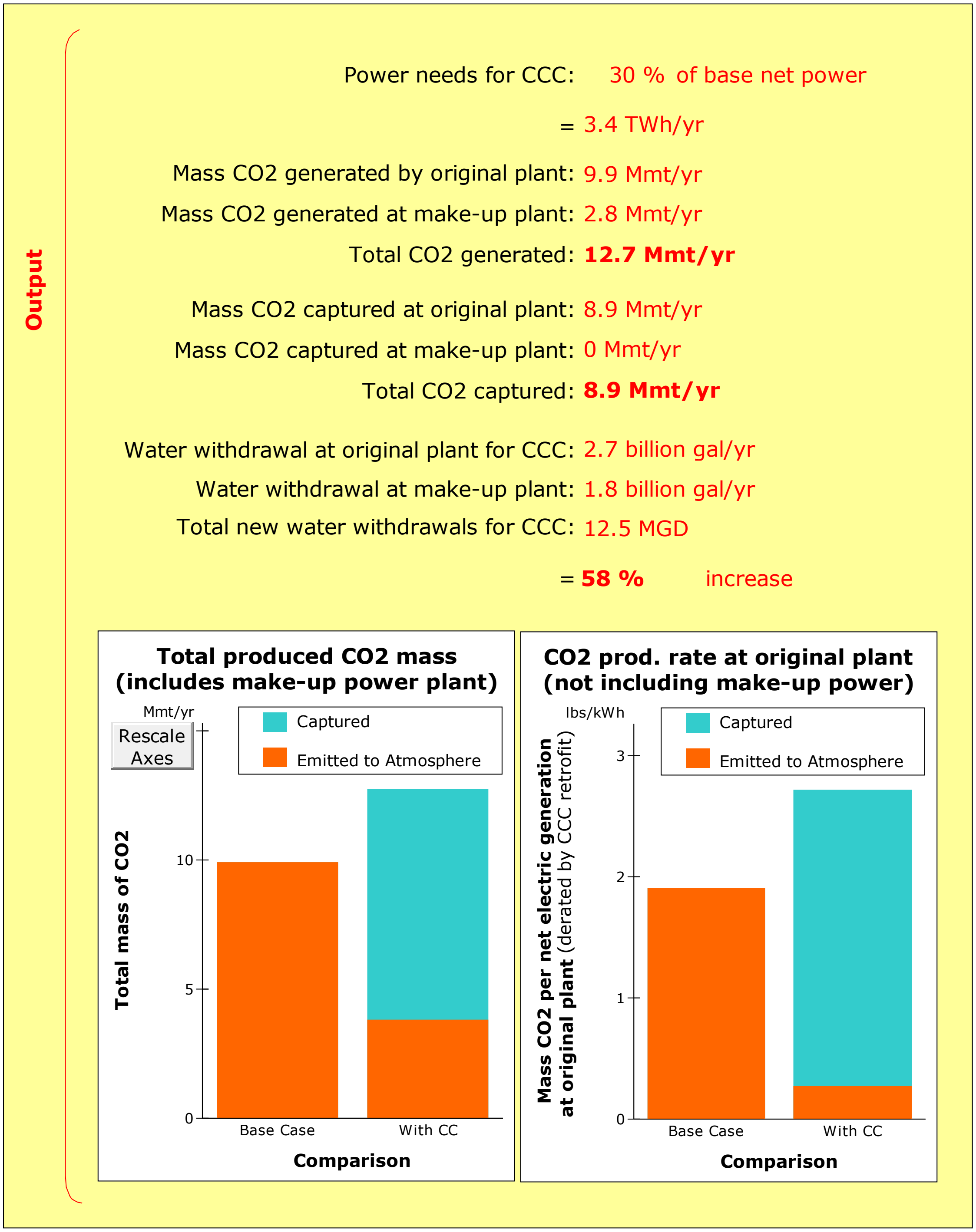


Figure 5-2. User interface outputs from WECS II CO_2 capture module include parasitic energy requirements, CO_2 generation and water use values associated with both original and makeup power plants. Note: The bar chart on the left shows that the total amount of CO_2 generation increases with CO_2 capture, but the amount released to the atmosphere decreases. The bar chart on the right shows that the amount of CO_2 generated per net energy produced *at the source plant* goes up due to the decrease in net energy production resulting from the parasitic energy requirements of CO_2 capture.

6. Carbon Storage Module

The carbon storage or ‘sequestration’ module utilizes geological information to calculate sequestration costs. The module does so based on the selected power plant with respect to any of the 325 geologic formations potentially available for carbon sequestration. Figure 6-1 illustrates the WECS II carbon storage module interface.

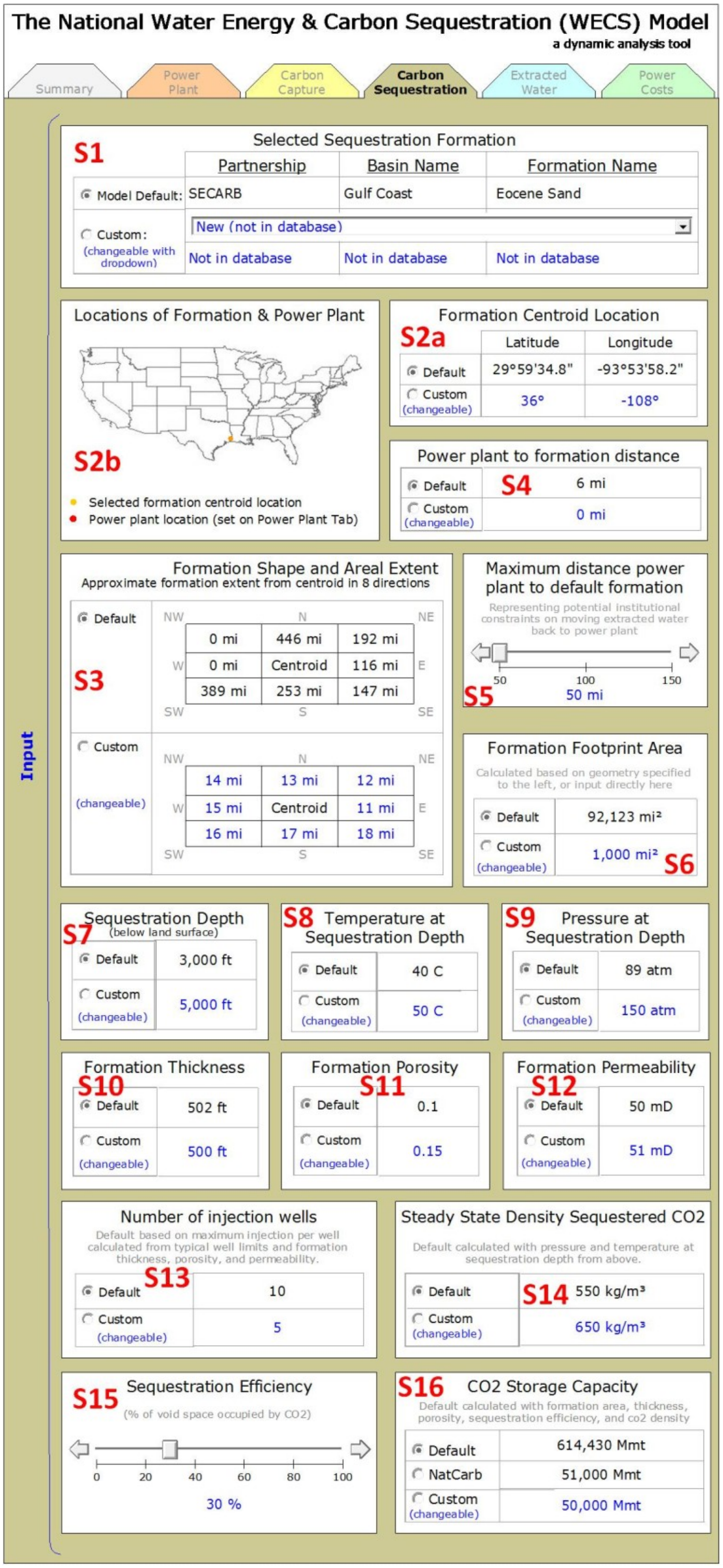


Figure 6-1. User interface inputs to WECS II carbon sequestration module.
Note: Values in blue and radio buttons or slider bars can be changed by the user. The numbers in red are superimposed here to supplement the input option description.

Carbon Sequestration Module Inputs

The carbon sequestration module estimates the cost of piping and injecting CO_2 from the specified source into a given formation. The user interface for inputs to the carbon sequestration module is shown in Figure 6-1. The module calculates the costs associated with transportation and sequestration of the CO_2 specified by the CO_2 capture module from the source specified by the power plant module, to any given formation considered for sequestration. The default formation used is the least cost formation with respect to both CO_2 sequestration and water extraction and treatment, and is provided by the power cost module. Object S1 in Figure 6-1 shows the default formation, as well as a radio button and dropdown that can be used either to define a new formation, or select one of the other 325 formations in the carbon sequestration module. If the option to add a new formation that is not in the database is selected in object S1, the default values in objects S2-S16 will be set to '?', and the model user will be required to put in all of the values to get model results. If the user selects a formation from the 325 available, then the default values for objects S2-S16 will be specified based on the chosen formation. The partnership, basin, and formation name for each of the 325 formations are from the National Carbon Atlas (NatCarb, 2008) database.

The carbon sequestration module must provide a cost estimate for carbon sequestration to all of the formations considered. To make this calculation, the carbon sequestration module begins by calculating the distance from the power plant selected to each of the potential formations. A centroid location for the target formation is specified in object S2a of Figure 6-1, with a default based on the National Carbon Atlas (NatCarb, 2008) database for the given formation. As is the case throughout the WECS II interface, default values are based on the best possible estimate, but the model user is given the ability to override any default value with a custom value, in this case by selecting the 'Custom' radio button and changing the blue text in object S2a. The specified centroid location is displayed (along with the power plant location) in object S2b. In order to calculate the distance between the power plant and the formation, the spatial area of the formation is estimated such that a CO_2 pipeline would only need to extend to the edge of the formation, and not to the actual formation centroid. For modeling purposes, the footprint shape of the formation is defined as the relative distance from the centroid to the edge of the formation in the eight cardinal and ordinal directions (N, NE, E, SE, S, SW, W, and NW). The 325 default formation shapes were defined by analyzing the geospatial output from the National Carbon Atlas (NatCarb, 2008) as described in Appendix A. Object S3 in Figure 6-1 shows the default shape for the formation specified by object S1, with the option for the user to define a custom shape by selecting the appropriate radio button and changing the blue values appropriately. Using the information from objects S2, and S3, the model calculates the great circle distance (distance in a straight line along the surface of the earth) between the power plant and the closest edge of the specified formation, which is used as the default distance in object S4, though again, the user can specify a custom distance. Although the carbon sequestration module calculates expected sequestration costs for all formations, only formations within the distance specified in object S5 in Figure 6-1 will be considered as the model's default formation. The critical distance can be relaxed somewhat by the user, but is implemented to capture potential institutional constraints to moving extracted water long distances from the formation back to the power plant. Object S6 uses values specified in object S3 to calculate a default footprint area, which can be overridden with a custom value.

Next, the module calculates the depth of sequestration. The depth of sequestration is within a 500' interval starting at 2500' to 3000', then 3000' to 3500' and so on up to 9500' to

10,000’ which is the maximum sequestration depth considered. Object S7 in Figure 6-1 specifies the top of the sequestration depth interval. Due to data limitations in the Carbon Atlas (NatCarb, 2008) with respect to formation thickness and depth, the default sequestration depth interval is calculated as the depth interval whose depth contains the maximum number of completed, potentially intersecting well records. If information on formation depth and thickness improve, the formation selected may be able to determine the sequestration depth without associated well analysis.

Once the depth of sequestration has been determined, default values for temperature and pressure at the sequestration depth are calculated based on geospatial temperature gradient estimates, and an assumed hydrostatic pressure gradient starting at the surface. The default values populate objects S8 and S9 of Figure 6-1, and as in the rest of the model, can be changed by a user with better information. With the temperature and pressure points, the steady state density of sequestered CO_2 is calculated and used to populate the default value in object S14.

Default values for formation thickness, porosity, and permeability are specified in objects S10 – S12 for the chosen formation based on published data in the National Carbon Sequestration Atlas (NatCarb, 2008) where available and general estimates based on relationships between formation geology, depth, and porosity/permeability where no data was available. The methodology for these estimates is still under development. Permeability, flow rate, and basic well property assumptions will be used to calculate the number of injection wells needed. This calculation has not been fully implemented into the model at this time however the result of the calculation will populate the default for object S13, which like all of the other model defaults, can be overridden by the model user.

Object S15 in Figure 6-1 specifies the sequestration efficiency or ‘sweep efficiency’ (the percent of void space that would actually be occupied by supercritical CO_2). A default sweep efficiency of 30% is used for all formations. Current geomodeling efforts may allow some formation specific estimates of sweep efficiency in which case the single slider bar in object S15 would be replaced by a dynamic default and custom option like many of the other inputs to the carbon sequestration module. Sequestration efficiency is used along with the formation area, thickness, porosity, and CO_2 density to calculate the mass sequestration capacity of the formation, which becomes the default value in object S16. Using object S16, the model user can choose between the calculated default storage capacity, the NatCarb reported capacity, or a custom value.

Carbon Sequestration Module Outputs

For all 325 potential formations, the distance between source and sink, the depth of sequestration, the number of injection wells needed, and the capacity of the formation is passed to the power costs module and ultimately the formation’s overall systems cost. Additionally, salient variables to the underlying calculations are displayed in the output section of the carbon sequestration module user interface shown in Figure 6-2.

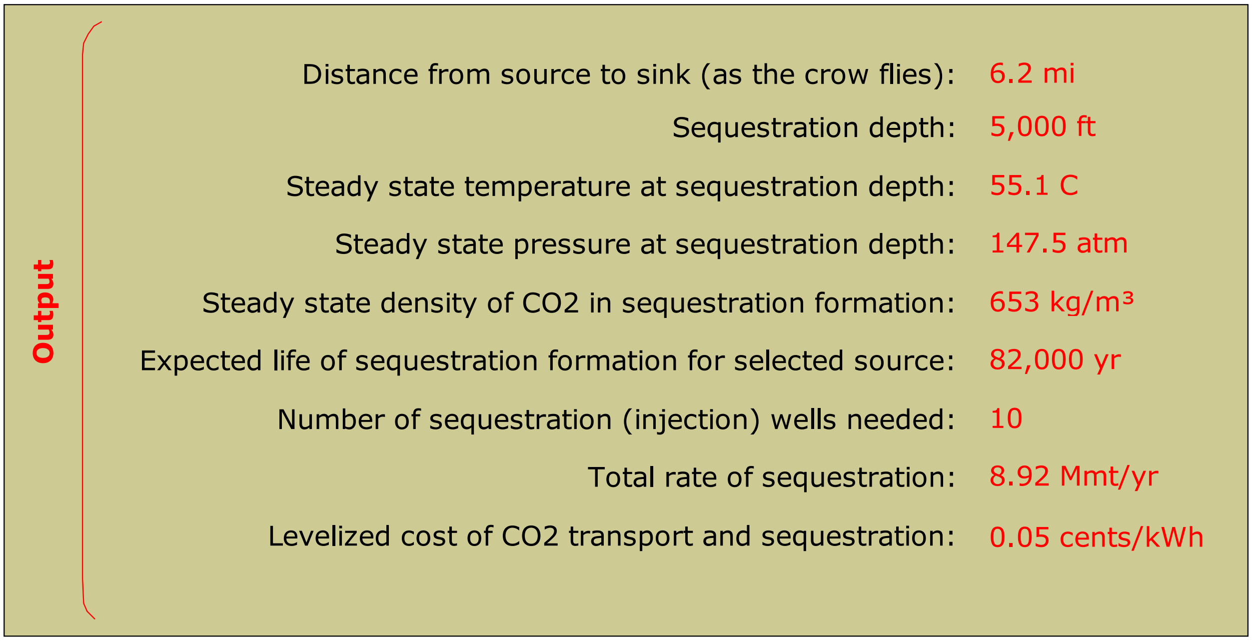


Figure 6-2. User interface outputs from WECS II carbon sequestration module.
Note: Includes the distance between power plant and sink, depth and rate of sequestration, steady state temperature, pressure, and resulting CO_2 density at the sequestration depth, expected life of the formation, required number of injection wells, and the levelized cost of the CO_2 transport and sequestration per unit of energy generated.

7. Extracted Water Module

Extracted Water Module

The WECS II model assumes that water will be extracted from the sequestration formation. This extraction may be used to manage pressure build up, control plume migration, and provide a means to offset increased water demands associated with CO_2 capture and sequestration. While the WECS II model does not fully incorporate spatial extraction locations or temporal extraction schedules that might optimize the sequestration capability of the formation at this time, the extracted water module does track the costs that would be associated with transporting the extracted water back to the power plant for treatment and use.

Extracted Water Module Inputs

User input options for the extracted water module are shown in Figure 7-1 below. Objects W1 and W2 determine the range of water quality defined by total dissolved solids (TDS) to be targeted by the extraction wells. The TDS units are defined in parts per thousand (ppt). Based on this range and the distribution of salinity in the formation, the model chooses a default extraction depth interval of 2,500'–4,999', 5,000'–7,499', or 7,500'–10,000' to minimize water extraction and treatment costs. The default interval can be replaced with a custom depth in object W5 in Figure 7-1. The WECS II model assumes that extracting waters from any of those depth intervals can accomplish desired pressure relief and plume management goals regardless of the depth of sequestration. Once the salinity range and extraction depth range have been selected, the model can calculate the probability of drilling a well with acceptable water quality which becomes the default value in object W3 in Figure 7-1. The model assumes that if a bore hole intercepts water quality within this range, the well is completed, and otherwise the hole is abandoned and another exploratory hole is drilled. Thus, the probability has cost implications associated with drilling wells that cannot be used. The distribution of water qualities in the formation at the given depth for useable wells then determines the average salinity expected from useable wells which is the default value in object W4. The default values in objects W3, W4 and W5 can be replaced with a custom value by checking the appropriate 'Custom' radio button and changing the associated blue value as desired.

In object W6 of the extracted water interface shown in Figure 7-1, the user can specify how much water is actually removed from the formation with the default value being an equal volume to the volume of CO_2 injected into the formation. The extracted water module will use permeability, porosity, and formation thickness to estimate the number of extraction wells needed to achieve the target water extraction, and that value will populate the default option in object W7. That calculation has not yet been fully implemented in the model.

The extracted water module also selects a least cost default brine disposal method based on the least cost method for a particular power plant. The brine disposal methods currently considered are evaporation ponds, delivery to the ocean, and injection back into the source formation, with a brine concentrator option planned for incorporation in the next model iteration. The default method can be changed with object W8 of the extracted water interface shown in Figure 7-1. The relative cost of these disposal methods varies with net evaporation at the power plant, distance of the plant to the ocean, and distance between the plant and the saline formation being utilized. Net evaporation is specified in object W9 with a default rate that will be based on geospatial data that has yet to be incorporated into the model. The net evaporation rate and the amount of evaporative cooling required determine the required evaporation pond area default in object W10. The distance from the plant to a deep brine injection plant is specified in object W11 with a default value set to the distance between the plant and the sequestration formation based on the assumption that brine can be disposed of in the same formation. The distance from the plant to the ocean is specified in object W12 with a default value based on the minimum distance to any point in a set of latitude longitude points that roughly defines the coastline of the United States.

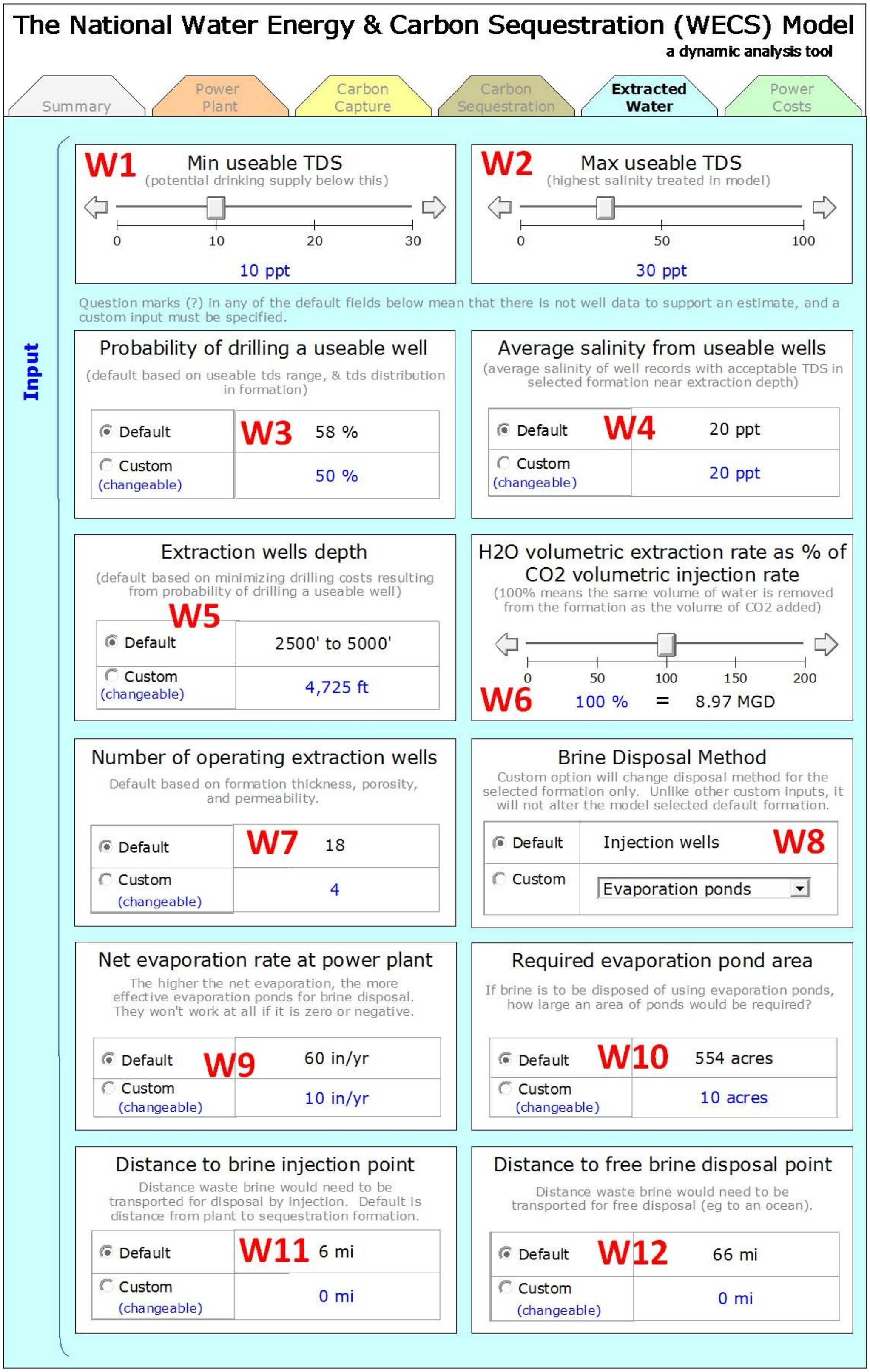


Figure 7-1. User interface inputs to WECS II extracted water module showing adjustable inputs.
Note: Values in blue and radio buttons or slider bars can be changed by the user. The numbers in red are superimposed here to help with the description of the input options.

Extracted Water Module Outputs

Once the extracted water module has calculated the quantity and quality of extracted water, the distance to the power plant, the depth and number of bore holes and completed wells, and parameters such as distance to a brine injection location, an ocean, or the area of evaporation ponds necessary for brine disposal, this information is transferred to the power cost module. Additionally, select variables including a histogram of water quality in well records associated with the geologic formation in the target extraction depth range are displayed as output in the user interface of the extracted water module (Figure 7-2).

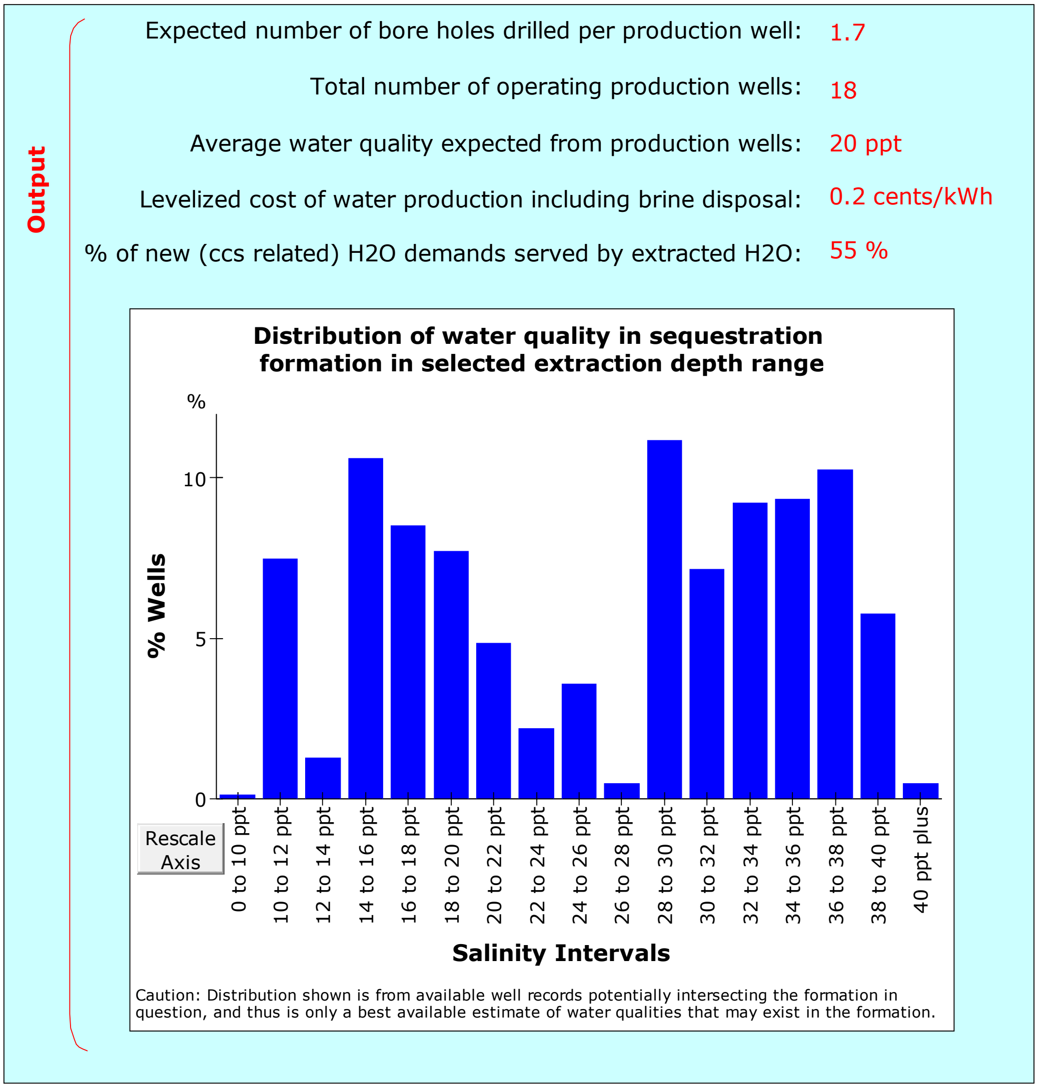


Figure 7-2. User interface outputs from the WECS II extracted water module.
Note: These outputs include the number of expected bore holes to be drilled per operational extraction well, the number of operational extraction wells, the average water quality from the extraction wells, the water extraction and treatment related costs levelized by the energy production at the power plant, the percentage of new water demand served by the extracted water, and a histogram of water quality in well records associated with the geologic formation in the target extraction depth range.

8. Power Cost Module

Information related to base energy production, carbon capture and compression, carbon transport and sequestration, and water extraction, transport, and treatment is passed from the power plant module, the carbon capture module, the carbon sequestration module, and the extracted water module to the power cost module as illustrated in Figure 3-1. The power cost module uses this information to determine the least cost formation for sequestration and water extraction. It also calculates changes to LCOE based on capital and operation and maintenance costs associated with carbon capture and use of the selected formation for sequestration and water extraction.

Power Cost Module Inputs

The interface for the power cost module is the most extensive in the WECS II model and is broken into 3 different images shown in Figure 8-1, Figure 8-2, and Figure 8-3. Object $1 in Figure 8-1 allows the user to specify the display year for dollar values in the model. For example, if this value is set to 2000, all dollar values displayed by the model as output or default values will be displayed as the year 2000 dollars. The correction for selected reference year is calculated based on the historic United States Gross Domestic Product Chained Price Index which is available by year from 1940 to 2014 (2009-2014 estimated) from OMB (2010).[iv]

Object $2 specifies the loan interest rate and loan period that is used for calculation of the capitalization factors according to a standard payment function. If the remaining power plant life (specified in object P6 of the power plant inputs) or expected life of the sequestration formation is shorter than the loan period specified in object $2, the shorter period will be used to calculate the capitalization factor instead thereby making the project more expensive in terms of LCOE. Object $3 is the same as object P9 in the power plant module inputs discussed previously in Section 4 (Figure 4-1). It is reproduced in the power cost interface for completeness and user convenience.

Inputs Associated with Costs of Carbon Capture and Compression

Object $4 in Figure 8-1 contains assumptions related to costs of carbon capture and compression for amine scrubbing processes and for Selexol based processes. WECS II assumes amine scrubbing technology for all plant types with the exception of IGCC, which are assumed to use Selexol technology. Estimates for amine technology costs were derived from the NETL report (2007b) which describes costs associated with capture of 30%, 50%, 70%, and 90% of CO_2 emissions from the Conesville #5 pulverized coal unit in Ohio using advanced amine based capture technology. Values reported in Table ES-1 of that report include capital costs and fixed and variable operations and maintenance (O&M) costs associated with different amounts of CO_2 capture. Cost data was compared to the amount of carbon captured and regressions created for capital cost, fixed O&M, and variable O&M costs as a function of CO_2 captured. The amine equations are shown in the first 3 data rows of Table 8-1. See Appendix B for more detailed information on these equations.

[iv] Multiplying a dollar amount from year X by the index for the desired base year divided by the index for year X results in the desired base year dollar amount.

Estimates for Selexol based processes were derived from the NETL report (2007a) which includes costs and performance information for IGCC plants with and without Selexol based CO_2 capture technology. In this case, the difference in cost with and without CO_2 capture was divided by the difference in emissions with and without CO_2 capture to get an estimate of the added costs associated with Selexol based CO_2 capture. This approach is based on costs of new IGCC plants, and may underestimate costs for CO_2 capture in a retrofit situation. A method based on retrofit costs should be developed when retrofit specific information becomes available. The Selexol equations are shown in the last 3 data rows of Table 8 below. See Appendix B for the raw data manipulations that result in the Selexol equations.

Unit differences account for the difference between the values in Table 8-1 and the values seen in object $4 of Figure 8-1. It is interesting to note that the capital costs and the combined O&M costs are substantially smaller per mass of CO_2 captured for the Selexol processes than for the amine based processes. This difference suggests that existing IGCC plants represent one of the relatively more economical options for CO_2 capture retrofits.

Table 8-1. Equations relating capital costs, variable operations and maintenance (VO&M) costs, and fixed operations and maintenance (FO&M) costs to the amount of CO_2 captured using amine technologies. Note: The goodness of fit (R^2) parameter refers only to the fit of the amine equations to four estimated points from one report (NETL, 2007b) on one pulverized coal unit, and not to the overall reliability of these equations.

Cost Type	Equation (all $ are year 2006)	R^2
Amine Capital	CCost[$1000] = 839.59*$CO_2$Captured[tonne/hr] + 119453	0.98
Amine VO&M	VO&M[$1000/yr] = 46.183*$CO_2$Captured[tonne/hr] + 1838.6	1
Amine FO&M	FO&M[$1000/yr] = 2.6896*$CO_2$Captured[tonne/hr] + 1556.9	1
Selexol Capital	CCost[$1000] = 361.8*$CO_2$Captured[tonne/hr]	NA
Selexol VO&M	VO&M[$1000/yr] = (3.1+153*CoalCost[$1000/ton])*$CO_2$Captured[tonne/hr]	NA
Selexol FO&M	FO&M[$1000/yr] = 5*$CO_2$Captured[tonne/hr]	NA

Note that the costs discussed above do not include costs associated with parasitic energy losses and the makeup power required to offset these. The parasitic energy losses are specified with objects C1 and C2 in the carbon capture module user interface inputs shown in Figure 5-1, and the makeup power costs are specified in object C6 of the same figure. The Make-Up Power LCOE table at the bottom of object $4 in Figure 8-1 is the same as object C6 of the carbon capture module user interface inputs shown in Figure 5-1.

Inputs Associated with Costs of CO_2 Transport and Sequestration

Object $5 in Figure 8-2 allows the user to manipulate parameters associated with estimation of CO_2 pipeline costs. The equation used was developed by Ogden (2002) as follows:

Cost (Q,L) = \$700/m x (Q/Q_o)0.48 x (L/L_o)0.24

where Cost is capital cost in 2001 dollars, Q is the flow rate of the pipeline being built, Q_o is a reference flow rate of 16,000 tonnes per day, L is the length of the pipeline being built, and Lo is a reference length of 100 km. The 0.48 and 0.24 determine how sensitive the cost is to differences in the flow rate and length from the reference values. Operations and maintenance costs are assumed to be 4% of capital costs. Object $5 in Figure 8-2 gives the user the ability to change all of the numbers in the Ogden equation as well as the O&M costs as a percent of the capital costs.

Object $6 in Figure 8-2 specifies parameters for determining injection well costs with a default method also following Ogden (2002). Injection wells are assumed to cost $1.25 million plus $1.56 million per kilometer of depth, all in 2001 $US. Operations and maintenance costs associated with injection wells are assumed to be 1.5% of capital costs. Any of these numbers can be changed by the model user with object $6. The WECS II model assumes that the potential energy of the CO_2 going down an injection well is sufficient to preclude the need for additional energy to actively pump the CO_2 down into the formation. As a result, no additional energy costs are added to the injection well costs.

It is important to note that the WECS II model currently has no cost associated with buying or leasing subsurface pore-space in the formation for storing of CO_2. The legal issues associated with pore-space ownership are still being explored. As information becomes available, these costs may be added to the WECS II model. Until then, the implicit assumption is that these costs will be small compared to the costs already incorporated in the model.

Inputs Associated with Costs of Water Extraction, Transport, and Treatment

Objects $7, $8, $9, and $10 in Figure 8-2 and 8-3 allow the model user to manipulate baseline assumptions related to the cost of extracting water from the sequestration formation, transporting it back to the power plant, treating it there for use in the power plant, and disposing of resulting brine concentrate. Object $7 in Figure 8-2 deals with the extraction well field costs. As a default, the WECS II model assumes that the well capital costs are $375 per foot of depth and million gallons per day (MGD) of extraction, in year 2000 $US. So a well 1000 feet deep extracting 10 MGD would cost $375*1000*10 = $3.75 million year 2000 dollars. This methodology follows that used in the WECS I model (NETL, 2009a), which was based on data published in Figure 9-18 of the 2003 Desalting Handbook for Planners (USBR, 2003). WECS II uses the estimated distribution of water qualities in a given formation to calculate the likelihood of drilling a well that cannot be used because the water that would be extracted would be outside the range of acceptable qualities defined in the extracted water module.

In the case that a well is drilled that cannot be used, WECS II assumes that 75% of the cost of a completed well is spent on drilling only, and is lost to any unusable effort. This drilling-only portion of total well costs can be changed by the model user in object $7. Unlike the case for the injection wells where the CO_2 is gravity fed into the injection well, the water extraction well will require substantial amounts of energy to lift the specified amount of water from the extraction well depth. The efficiency of the pumps is assumed to be 68%, but can be changed in object $7. The mass of the water extracted times the acceleration of gravity times the depth of the extraction well divided by the pump efficiency gives the energy requirements for pumping the wells. Multiplying this energy requirement by the cost of make-up power specified in object P9 in the power plant module inputs results in the annual energy costs associated with extraction of the water. Finally, the model adds an additional 1.5% of capital costs as non energy related O&M. All of these numbers can be changed by the model user in object $7 shown in Figure 8-2.

Object $8 in Figure 8-2 can be used to adjust assumptions related to the costs of transportation of extracted water by pipeline from the extraction location to the power plant. Following the methodology of the WECS I model (NETL, 2009a), which was based on data published in Figure 9-11 of the 2003 Desalting Handbook for Planners (USBR, 2003), the capital cost of water pipelines (in year 2000 $US) is calculated as $111,314 per mile plus an additional $35,761 per mile per MGD of flow. Thus, a pipeline 100 miles long carrying 10 MGD would have a capital cost of $111,314*100 + $35,761*100*10, or about $47 million year 2000 dollars. Energy costs of the water pipeline are calculated based on the friction coefficient of the pipeline times the length of the pipeline, times the mass of the water being transported times the acceleration due to gravity divided by the efficiency of the pipeline pumps. The well pumps efficiency from object $7 is used as the pipeline pump efficiency. No elevation change from the point of extraction to the treatment plant is currently incorporated. Finally, an additional 1.5% of capital costs are assumed as the non energy related O&M costs of the pipeline. Object $8 can be used to change any of these parameters.

Object $9 seen in Figure 8-3 handles estimates of water treatment costs. The WECS II model assumes use of High Efficiency Reverse Osmosis (HERO) water treatment. The feed flow referenced in object $9 refers to the total amount of untreated water that enters the treatment plant. The plant capacity on the other hand is the design capacity of treated water that the plant can produce. Following the methodology developed in the WECS I model (NETL 2009a), the capital cost of the treatment plant is calculated as the sum of two components, one for piping infrastructure, and one for the treatment related infrastructure. The default values for these in 2004 dollars are $779,931 per MGD feed flow for the piping, and approximately $3.5 million per MGD feed flow for the treatment.

Annual labor costs in year 2000 $US are calculated as $171,778 per year per gallon per minute of plant capacity multiplied by the plant capacity raised to the 0.2322. Annual energy requirements for water treatment are calculated as 2.41 kWh/1000 gallons of treated water plus 0.6 kWh/1000 gallons of treated water/ ppt of treated water produced. So if 1,000 gallons of water are treated from an initial TDS of 15 ppt to a treated TDS of 1 ppt, the energy required would be 2.41+0.6*14 or 3.25 kWh. This energy requirement is then multiplied by the cost of make-up power specified in object P9 in the power plant module to get an annual electricity cost for water treatment. In addition to labor and electricity costs, other variable costs considered explicitly are membrane replacement costs and chemical replacement costs, which are given default values of 8 cents and 59 cents (2004 $US) per 1000 gallons of treated water respectively. Finally, an additional 1.5% of O&M is added to cover other variable costs not related to labor, electricity, membrane replacement or chemical replacement costs associated with water treatment. All of these default values can be changed by the model user by highlighting the appropriate blue text in the interface object $9.

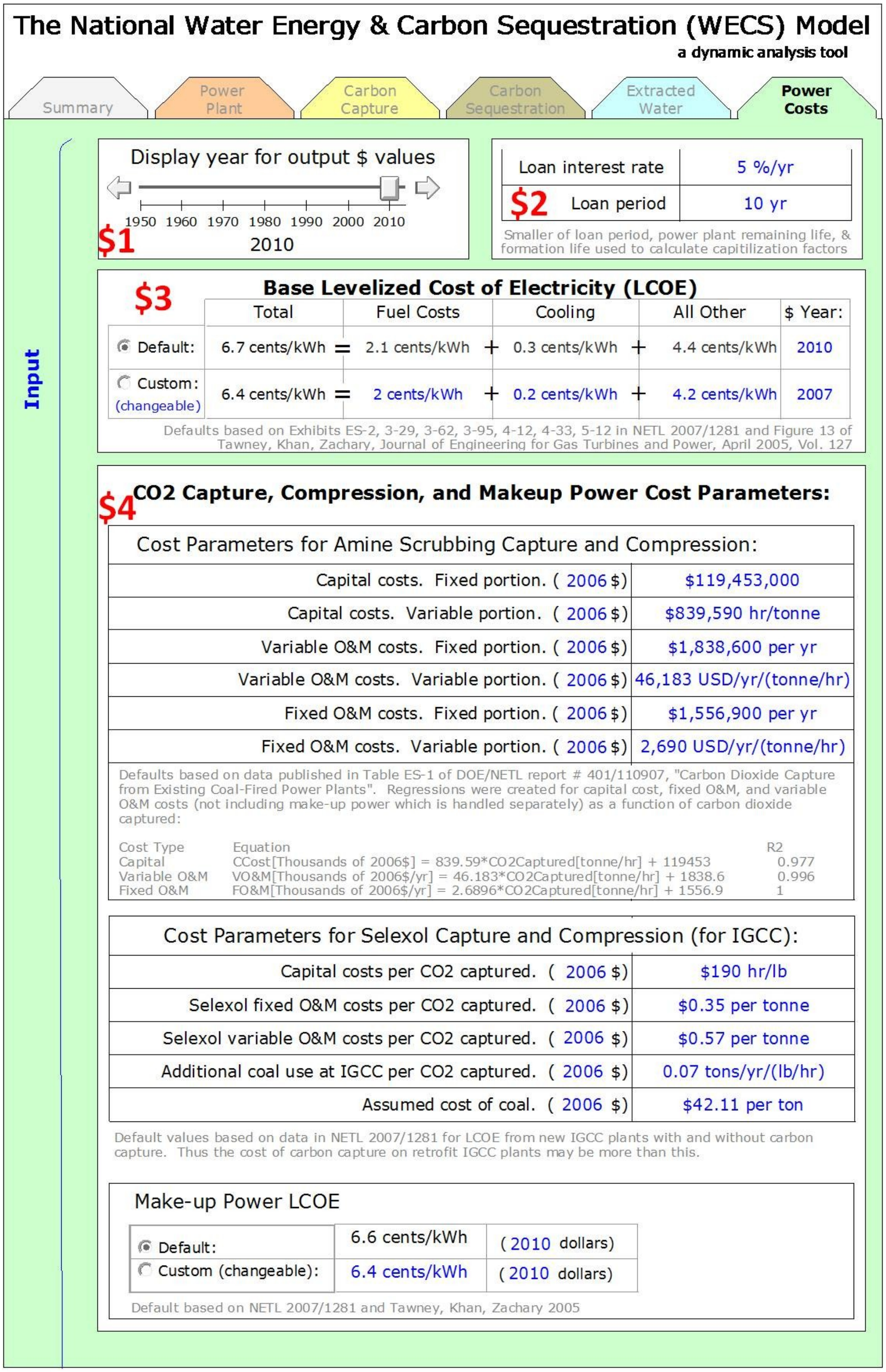


Figure 8-1. User interface inputs (Screen 1 of 3) to the WECS II power costs module showing adjustable inputs.

Note: Values in blue and radio buttons or slider bars can be changed by the user. The numbers in red are superimposed here to help with the description of the input options.

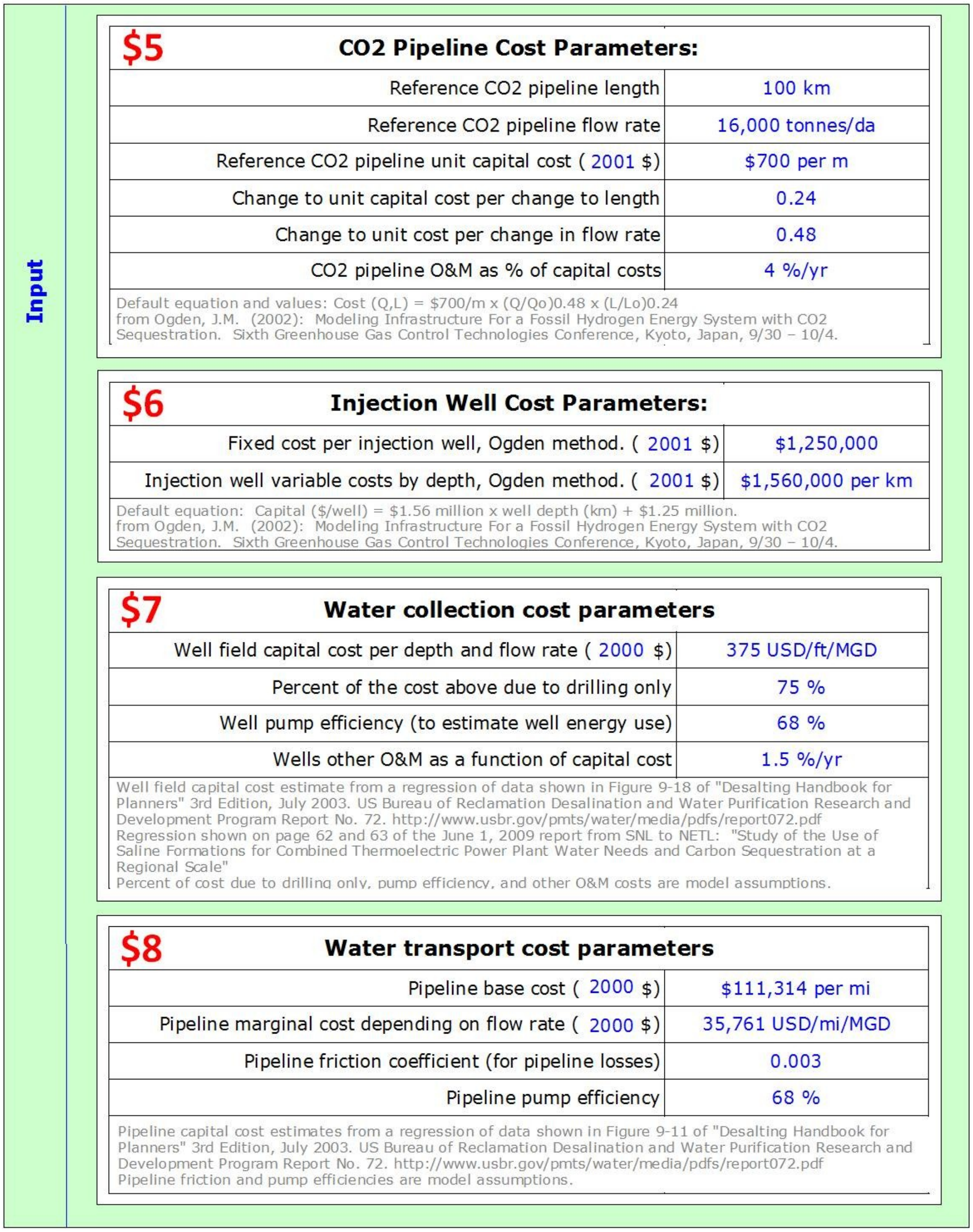


Figure 8-2. User interface inputs (Screen 2 of 3) to the WECS II power costs module showing adjustable inputs.
Note: Values in blue and radio buttons or slider bars can be changed by the user. The numbers in red are superimposed here to help with the description of the input options.

Input

$9 Water treatment cost parameters	
High Eff. Reverse Osmosis plant capital costs per feed flow	$3,535,545 per MGD
Recving, transfer, distribution piping capital costs per feed flow	$779,931 per MGD
Dollar year for capital costs listed above	2004
Annual labor costs coefficient per treatment plant capacity	171,778 USD/yr/(gal/min)
Annual labor costs plant capacity exponential	0.2322
Dollar year for labor costs listed above	2000
High Efficiency Reverse Osmosis (HERO) base electricity use	2.41 kWh/1000gal
HERO water quality dependent marginal electricity use	0.6 kWh/1000gal/ppt
HERO membrane replacement costs (2000 $)	8 cents/1000gal
HERO chemical replacement costs (2004 $)	59 cents/1000gal
HERO other O&M as a function of capital costs	1.5 %/yr

Capital costs and chemical replacement costs from Zammit and DiFillipo 2004 estimates of costs for a HERO plant with 1316 gpm model feed flow. "Use of Produced Water in Recirculating Cooling Systems at Power Generating Facilities" Deliverable #3
Labor costs from best fit exponential equation based on data in Figure 9-37 of "Desalting Handbook for Planners" 3rd Edition, July 2003. US Bureau of Reclamation (USBR) Desalination and Water Purification Research & Development Program Report No. 72. http://www.usbr.gov/pmts/water/media/pdfs/report072.pdf
Best fit equation: cost = $171778*PlantCapacity^0.2322
HERO electricity use parameters based on data in Figure 7-8 of the same USBR report.
Membrane replacement costs also based on data in the same USBR report.
Other O&M costs as a function of capital costs is a model assumption.

$10 Brine disposal cost parameters	
Evaporation ponds fixed capital cost:	$19,600
Evaporation ponds variable capital cost:	$244,900 per acre
Evaporation ponds O&M as % of capital cost:	1.5 %/yr
Injection wells fixed capital cost:	$2,359,271
Injection wells variable capital cost:	$194,893 per MGD
Injection pipelines and wells O&M as % of capital cost:	1.5 %/yr
Dollar year for evaporation ponds and injection well costs:	2000
All brine pipeline cost parameters are the same as for the water supply pipeline	

Evaporation ponds capital costs from best fit equation to data in Figure 9-12 of "Desalting Handbook for Planners" 3rd Edition, July 2003. US Bureau of Reclamation (USBR) Desalination and Water Purification Research & Development Program Report No. 72. http://www.usbr.gov/pmts/water/media/pdfs/report072.pdf
Injection wells capital costs from best fit equation to data in Figure 9-13 of the same.
Other O&M costs as a function of capital costs is a model assumption.

Figure 8-3. User interface inputs (Screen 3of 3) to the WECS II power costs module showing adjustable inputs.
Note: Values in blue and radio buttons or slider bars can be changed by the user. The numbers in red are superimposed here to help with the description of the input options.

Once the water has been treated, the resulting brine concentrate must be disposed, and the WECS II model currently evaluates three different brine disposal options: evaporation ponds, reinjection, and discharge to the ocean. A brine concentrator option may be added in the future. The parameters related to brine disposal can be adjusted in the power costs module user interface input object labeled $10 in Figure 8-3. Following the methodology of WECS I (NETL, 2009a), which is based on data published in Table 9-12 of USBR 2003, evaporation ponds are estimated to cost $19,600 plus $244,900 per acre. The area of evaporation ponds required is calculated in the extracted water module as discussed in section 7. Operations and maintenance costs associated with the evaporation ponds are assumed to be 1.5% of capital costs, however any of these values can be adjusted by the model user by selecting and changing the appropriate value in object $9 of Figure 8-3.

For brine discharge to the ocean or reinjection to the saline formation, pipelines are required. The distance of these pipelines is calculated in the extracted water module as discussed in Section 7, and the costs of the pipelines are calculated by the same methodology as for the extracted water pipelines discussed above. The flow rate of the concentrated brine pipelines will be less than it was for the extracted water, so in general the pipeline costs for the brine concentrate will be smaller than those for the extracted water. For brine concentrate discharge to the ocean, no additional costs are added, while for reinjection, there are additional costs associated with construction of injection wells. It may be possible to use the CO_2 injection wells for brine concentrate disposal, and may even have benefits related to CO_2 plume management, however for the purposes of the WECS II model, it is assumed that new injection wells will be required for the brine concentrate. Following the methodology of WECS I (NETL, 2009a), which is based on data published in Table 9-13 of USBR (2003) the cost of injection wells is calculated as approximately $2.3 million dollars per well plus approximately $194,893 per MGD of brine disposal all in year 2000 ($US). Operation and maintenance costs associated with brine pipelines and injection wells are assumed to be 1.5% of capital costs. Again, any of these values can be adjusted by the model user by selecting and changing the appropriate value in object $9 of Figure 8-3.

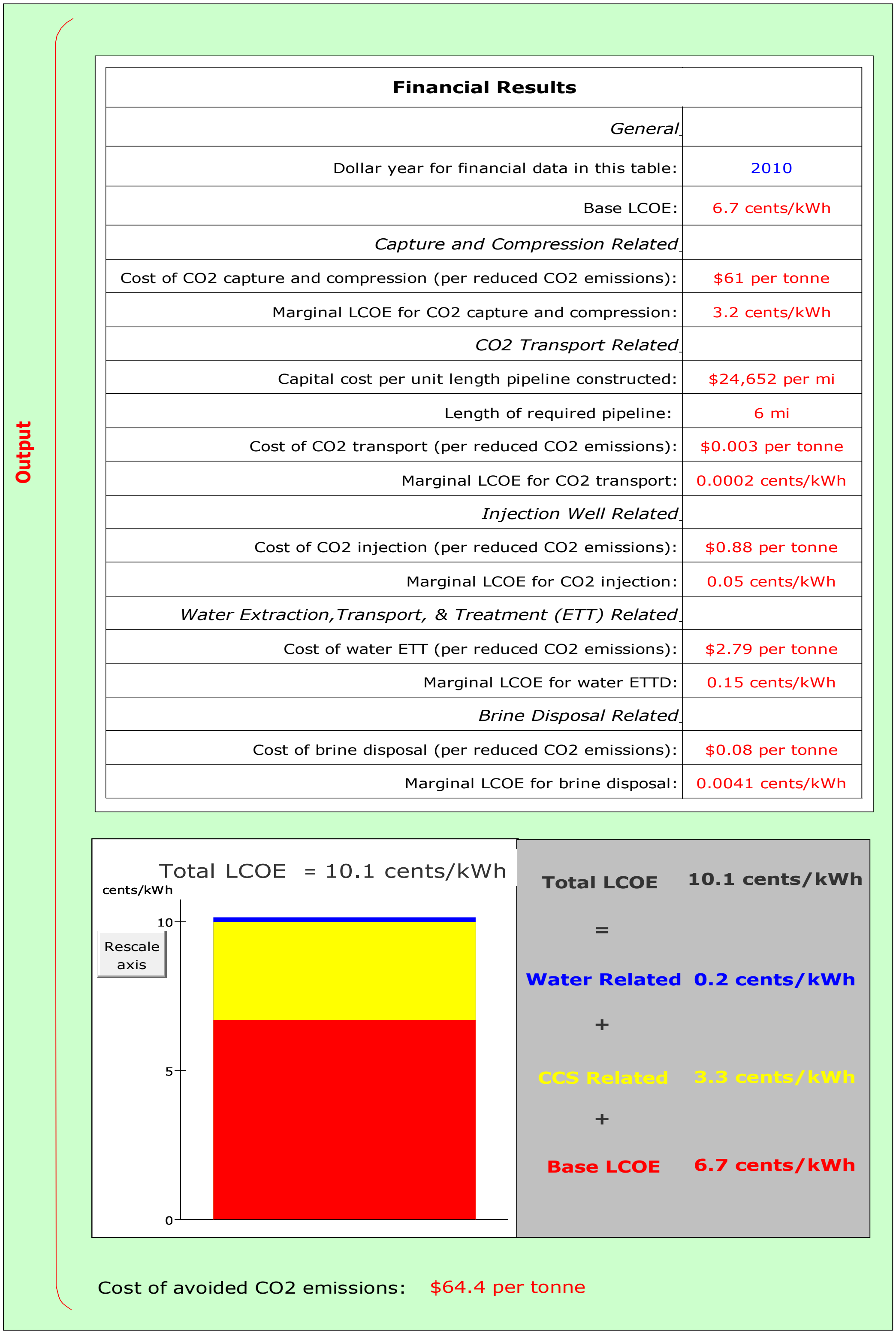
Selection of a Default Formation and Brine Disposal Method

The calculations of costs discussed above result in capital costs and annual costs associated with each component of CO_2 capture and sequestration with utilization of extracted water from the sequestration formation. As mentioned previously, a capitalization factor is calculated based on a user supplied loan interest rate (interface input object $2 in Figure 8-1) and a loan period that is the smallest of the user supplied loan period (interface input object $2 in Figure 8-1), the power plant expected remaining life (calculated in the power plant module based on interface input object P6 in Figure 4-1), and the sequestration formation expected life (calculated in the carbon sequestration module). Therefore, though unlikely, a small sequestration formation close to a large power plant may not be the most cost effective option if the formation would be filled in less time than the loan period.

Once all costs have been annualized, the total cost of CO_2 capture and sequestration with extracted water use is calculated by the WECS II model for all 325 formations, and for all three brine disposal methods. The smallest of these annualized costs is selected as the default cost, and the saline formation and brine disposal method associated with this cost are selected as the model default formation and brine disposal methods. These defaults are passed back to the carbon sequestration and extracted water modules and the default formation determines the default model values displayed in the carbon sequestration module interface input objects labeled S1, S3, S4, S7-S15, and S17 in Figure 6-1 and the extracted water module interface input objects labeled W3-W5, W7, and W9-W12 in Figure 7-1. These default values will change however if the user overrides the default formation with the carbon sequestration module input object labeled S1 in Figure 6-1. The default brine disposal option populates the default method displayed in the interface object labeled W8 in Figure 7-1, which refers only to the selected formation, and so does not have such wide reaching consequences if changed.

Power Cost Module Outputs

Once the annualized costs associated with CO_2 capture, compression, sequestration, and extracted water use have been calculated, they are can also be expressed in terms of levelized cost of energy (LCOE) simply by dividing the annualized costs by the annual energy output from the source plant. The source plant is unaffected by the new processes due the purchasing of make-up power to offset any parasitic energy losses. The power cost module displays the total LCOE resulting from adding CO_2 capture and sequestration with extracted water utilization, as well as the individual components of this total cost and important summary costs as seen in Figure 8-4.



Financial Results	
General	
Dollar year for financial data in this table:	2010
Base LCOE:	6.7 cents/kWh
Capture and Compression Related	
Cost of CO2 capture and compression (per reduced CO2 emissions):	$61 per tonne
Marginal LCOE for CO2 capture and compression:	3.2 cents/kWh
CO2 Transport Related	
Capital cost per unit length pipeline constructed:	$24,652 per mi
Length of required pipeline:	6 mi
Cost of CO2 transport (per reduced CO2 emissions):	$0.003 per tonne
Marginal LCOE for CO2 transport:	0.0002 cents/kWh
Injection Well Related	
Cost of CO2 injection (per reduced CO2 emissions):	$0.88 per tonne
Marginal LCOE for CO2 injection:	0.05 cents/kWh
Water Extraction,Transport, & Treatment (ETT) Related	
Cost of water ETT (per reduced CO2 emissions):	$2.79 per tonne
Marginal LCOE for water ETTD:	0.15 cents/kWh
Brine Disposal Related	
Cost of brine disposal (per reduced CO2 emissions):	$0.08 per tonne
Marginal LCOE for brine disposal:	0.0041 cents/kWh

Figure 8-4. User interface output from power costs module of the WECS II model.
Note: The levelized cost of energy without carbon capture and sequestration is shown in red in the bar graph and printed in red to the right of the bar graph. Carbon Dioxide (CO_2) capture and sequestration related costs are shown in yellow, and water extraction and treatment costs are shown in blue. The total costs of avoided atmospheric emissions of CO_2 are displayed at the bottom.

9. WECS II Summary Interface

Select interface objects from each module are brought together in a single interface page to provide the model user with an overall picture of the scenario under evaluation. Although many of the objects in the summary interface are input objects from other modules and can be used to change the scenario under evaluation, the goal of the summary interface is to put the most important parameters of the WECS II model in one place, and as such, the difference between input and output is not maintained as it is in the module specific interface pages shown throughout this report. The summary interface is shown in Figure 9-1.

The General Summary table labeled A1 in Figure 9-1 gives a high level summary of the base case scenario used to develop the model's components. The scenario highlights include the power plant capacity and type, the percentage of CO_2 being captured, the LCOE and water demand increases resulting from the CO_2 capture, the cost of avoided CO_2 emissions, the distance between power plant and sequestration formation, the size of the sequestration formation in terms of the estimated number of years of sequestration available, and the percent of water demand increase served by the extracted water.

The Power Plant Summary table labeled A2 in Figure 9-1 gives summary information from the power plant module including plant type, plant location, base electricity and CO_2 production, and base water withdrawals and consumption. The Carbon Capture Summary table labeled A3 gives summary information from the carbon capture module including % CO_2 captures, the resulting parasitic energy loss, CO_2 generation as a result of make-up power generation, the percent of this CO_2 that is captured, and the added water withdrawal demands associated with CO_2 capture and compression. The Carbon Sequestration Summary table labeled A4 gives summary information from the carbon sequestration module including the amount of CO_2 to be sequestered, and information about the formation under consideration for sequestration including location, the relevant Carbon Sequestration Partnership name, geologic basin and formation names, and the estimated number of years of sequestration available for the given sequestration rate. The Extracted Water Summary table labeled A5 gives summary information from the extracted water module including the rate of extraction, the treated water resource, the percent of added water demand associated with carbon capture and compression that is served by this resource, the target water quality, the extraction well depth, and the selected brine concentrate disposal method. The Power Costs Summary table labeled A6 gives summary information from the power costs module including the base LCOE, and the incremental LCOE associated with carbon capture and compression, CO_2 transport, and water extraction and treatment, the total new LCOE, the percent increase from base that this represents, and the cost of avoided atmospheric CO_2 emissions.

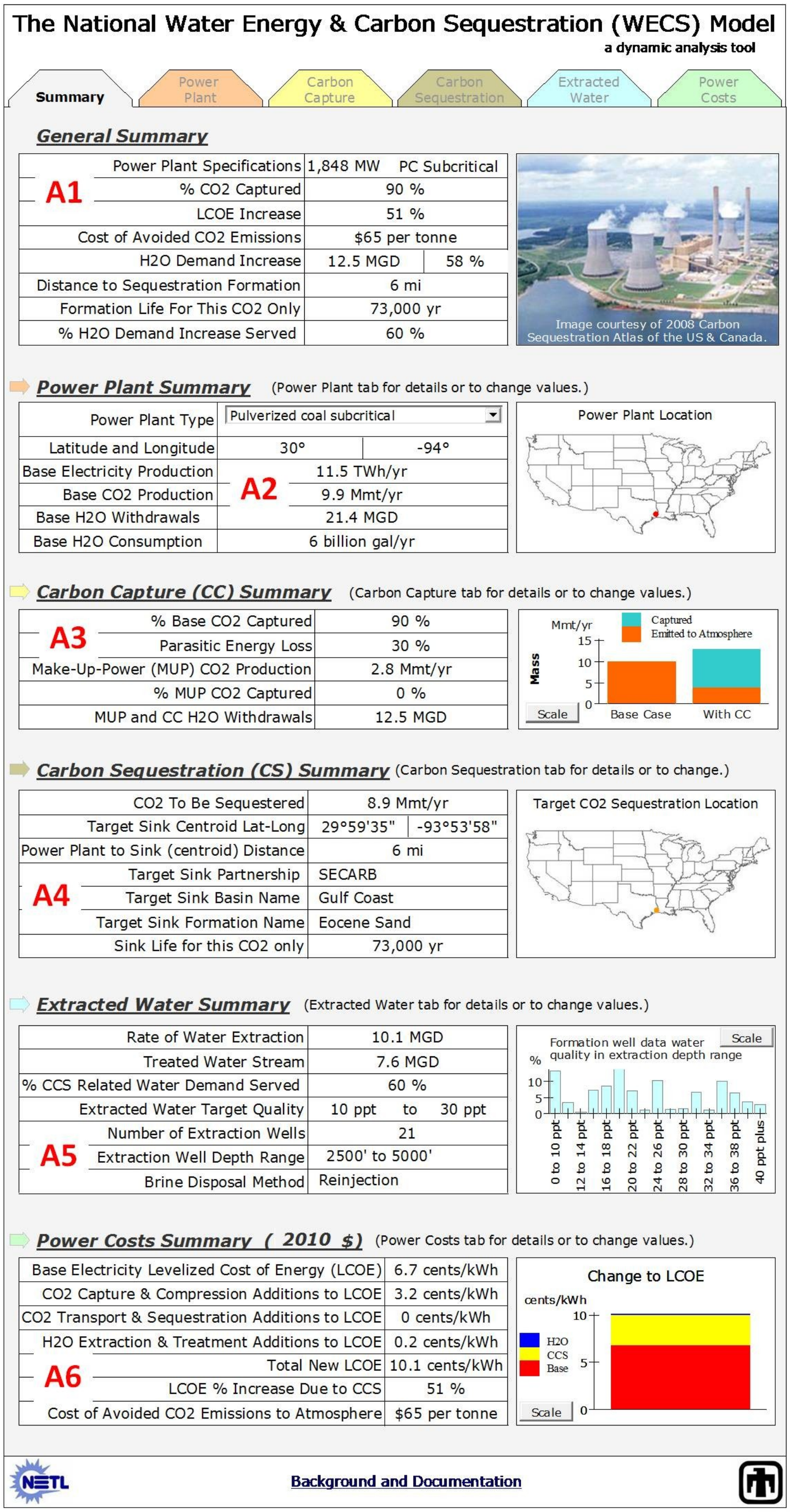


Figure 9-1. WECS II summary interface page.
Note: This page combines select information from all modules in an attempt to provide the important parameters associated with the scenario being evaluated by the model user. The numbers in red are superimposed here to help with the description of the interface components.

10. Ongoing and Future Work Efforts

In the near term, development efforts for the WECS II model will focus on completing the sequestration formation database and related interface updates. These updates will complete the first version of the model and allow a transition to analysis of model output. The first sets of analysis will be related to scenario testing of model results to relevant studies as an initial validation of model function. Following this phase of analysis, the national suite of existing coal and gas fired power plants will be analyzed with WECS II. Finally, some input uncertainty analysis will be incorporated to begin to estimate the uncertainty associated with the model. Each of these goals is discussed in further detail below.

Completion of Sequestration Formation Database

The WECS II model interface and structure have been completed, however data entries related to the potential sequestration formations are still being developed. There is tremendous uncertainty associated with the characterization of deep saline formations for a variety of reasons including observation difficulty, spatially heterogeneity, and to this point at least, very little reason to make the needed observations for the purposes of CO_2 sequestration. As a result, the dataset required to drive the WECS II model is limited, and in some cases nonexistent. It is important that WECS II maintain some transparency to the sources and quality of data used to populate the default properties of a given saline formation targeted for sequestration. Thus, as the data are filled in, the carbon sequestration module interface will be updated as needed to allow a level of transparency between the model user and the underlying assumptions related to the geologic data.

Each regional partnership was contacted to determine whether all of the site-specific attributes of their supporting data used to make the CO_2 capacity estimates as reported in the NatCarb database was sufficiently incorporated. All the partnerships were willing to share some of their data, however due to different methodologies and processes used to calculate the CO_2 capacity estimates, the data exist in different formats. Most of the information is geospatial and exists as either in shapefile, grid or geodatabase format. In some cases where the data was not available spatially, the partnership's Geographic Information System (GIS) contact was able to provide reports that may include data such as formation depth, thickness, porosity and other useful supporting data. A key report by Hovorka et al. (2000) that characterized certain saline formations in the U.S. was used where data from NatCarb or the regional partnerships is non-existent. In certain regions, specific databases that are publically available will also be used to supplement the regional partnership data. For example, the Texas BEG has a database of wells for the entire state, and includes additional water chemistry data that my help better characterize the formations that we are interested in. Some of this data may or may not overlap with the NatCarb and regional partnership data.

As mentioned in Section 3, the regional partnership data, as well as data from other sources will be used to characterize the saline formations in a way that will be most useful for the WECS II model. In areas where the data does not exist, the statistical approach will be utilized where the WECS II model will sample from the distribution of potentially intersecting saline wells. Approximations of other characteristics will be made based on formations with similar geologic conditions.

The analysis will look to include revised NatCarb Atlas saline formation data into the WECS II model when the data are made available. This effort by the regional partnerships and

NatCarb represents some of the best available data gathered at the national scale and should give the model an even more robust platform to provide insight into coupling CO_2 storage and extracted water use.

Scenario Testing of WECS II

Once the data, model, and interface structure have been completed, it will be important to check the WECS II model's results against other estimates of the costs associated with CO_2 capture and sequestration. This level of scenario testing will involve setting the input parameters in the model to match a situation or situations for which there is existing data or existing estimates associated with carbon CO_2 and sequestration costs. The WECS I model analysis of a specific power plant in northwestern New Mexico with sequestration to a specific formation nearby will be the logical first comparison (NETL, 2009a). Following this comparison, other relevant available studies will be compared to verify and validate the model to ensure it is generating meaningful and credible results.

National Power Plant Fleet Analysis

Following individual power plant scenario testing, the WECS II model will be used to evaluate the national fleet of existing coal and gas fired electricity generators. A database of current generator properties will be examined for the necessary power plant module inputs (shown previously in Figure 3-1), which will be fed into WECS II in an automated fashion to generate estimated cost information for CO_2 capture and sequestration for each individual power plant. These results will include the cost of avoided CO_2 emissions for each plant, which can be ranked, ordered, and plotted as an estimated supply curve for avoided CO_2 emissions in the early phase of CO_2 capture and sequestration efforts in the United States. It would be an early phase analysis because each power plant may be evaluated in isolation, with no competition from other power plants for geologic resources. A later phase analysis is planned for an expanded version of WECS II (see Table 3-1) which will incorporate the temporal dimension of national CO_2 capture and sequestration efforts such that as a plant adds CO_2 capture, the space available for sequestration is limited to pore space that other plants have not already reserved for their own sequestration programs.

WECS II Uncertainty Estimation

The magnitudes of uncertainty associated with input parameters to the WECS II model are likely to be dominated by the myriad of uncertainties associated with the storage capacity of the sequestration formations, however even parameters associated with current power plant operations exhibit substantial distributions around a mean. To this point, the WECS II model has been described as completely deterministic meaning that there is only one value associated with each input, and there is one set of outputs associated with a given set of inputs. Therefore, those outputs types (but with scenario-specific results) will be the same every time the model is run. If the distribution of uncertainties associated with the model inputs is known, or can be estimated, the model can instead be run as a stochastic model such that the inputs will be sampled based on their statistical distributions, and the outputs will vary accordingly. No two runs will be identical, but running the model many times will produce a distribution of results as a function of the uncertainties associated with the input parameters.

To incorporate stochasticity into the WECS II model, a probability distribution will be assigned to each of the model inputs described in the Power Plant, Carbon Capture, Carbon

Storage, Extracted Water, and Power Cost Modules. The resulting uncertainty will be passed through the model to generate probability distributions associated with model outputs. Thus, the likely bounds to model outputs such as the supply curve for avoided CO_2 emissions described above can be estimated. This will be the final step in WECS II model development, and once complete, the temporal scenario building that will characterize the expanded WECS II can begin. A path forward for incorporating uncertainty in geologic data into WECS II is discussed in the next section.

Uncertainty in Plume Extent, Sweep Efficiency, and Injectivity

Uncertainty in saline formation properties, both petrophysical and hydrological, will be an issue in underground CO_2 storage, as most viable saline formations have not been extensively drilled, cored, and studied as oil and gas reservoirs have, nor are they accessible to near surface investigations as groundwater-bearing aquifers. It is thus desirable to allow for uncertainty in reservoir and caprock properties in the WECS-type models, in an assessment of the economics of the coupled-use methodology. To assess amounts of uncertainty in the extent of CO_2 plume migration, sweep efficiency (i.e., volume of reservoir swept by the CO_2 plume), and injectivity, in this section the analysis examines a portion of the Illinois Basin, with the Mt. Simon sandstone as a likely candidate as storage reservoir. As in previous phases, the analysis conducts simulations of injection and storage using the TOUGH2 reservoir simulator (Pruess et al., 1999). In this assessment of Mt. Simon heterogeneity, the analysis requires subsurface information, which is limited in this portion of the Illinois Basin to about 20 or so boreholes. On the positive side, there are a number of natural gas storage sites that are presently operational from which insight into subsurface CO_2 storage can be gleaned.

The Mt. Simon sandstone, based on previous work by the Illinois Geological Survey and others (Finley, 2005), is an ideal candidate to develop a methodology to apply the WECS model to a site with limited subsurface data. The subsurface modeling portion of this study is applying geostatistical methods to delineate spatial extents of formation storage and conductivity, for which the analysis will derive probability distribution functions (PDF's) for plume extent, sweep efficiency, and injectivity. These can be used in the WECS II model as a means to handle subsurface uncertainty. This portion of the study develops and applies this methodology as a case study for both developing multiple realizations of possible subsurface heterogeneity for subsurface modeling based on available subsurface data, outlines procedures for obtaining PDF's of plume extent, and suggests how this can be used within the existing WECS framework.

Mt. Simon Geologic Framework Model

Tops of Precambrian crystalline rocks, the Mt. Simon sandstone which unconformably overlies it, and the Eau Claire Formation which conformably overlies the Mt. Simon, were determined from structure maps derived by the Midwest Carbon Partnership (Finley, 2005). A portion of these relevant to the depths and salinities of use to the WECS project, is shown in 3D, along with a surface digital elevation model, in Figures 10-1 and 10-2.

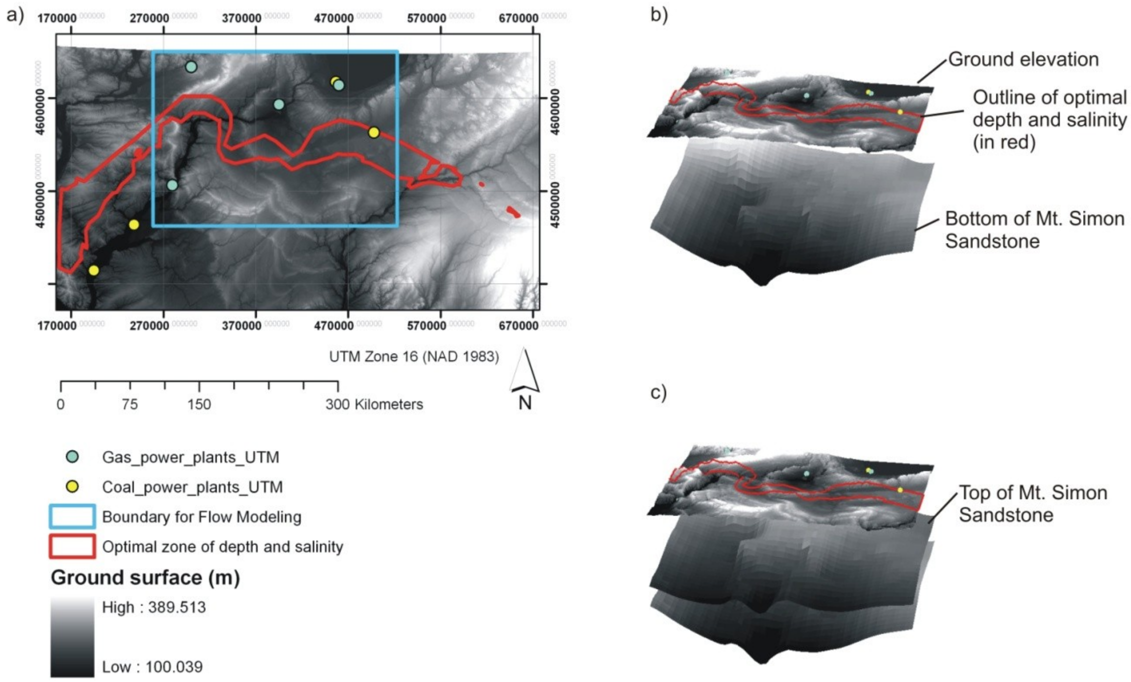


Figure 10-1. Elevation surfaces of the ground level and the top and bottom of the Mt. Simon Sandstone. Note: a) Plane view of the field site with locations of power plants, the optical zone of depth and salinity for coupled use (i.e., groundwater extraction and CO_2 sequestration), and the ground surface elevations. b and c) Three dimensional (3D) projections of ground surface and the top and bottom of the Mt. Simon Sandstone with a vertical exaggeration of 75×. These surfaces represent the raw data used to generate the bounding surfaces of the TOUGH2 3D flow model. The upper right hand corner of the DEM image shows the southern tip of Lake Michigan.

These surfaces were imported into the PETRASIM pre- and post processor for TOUGH2 and used for gridding large and small scale models for injection simulations (Figure 10-2).

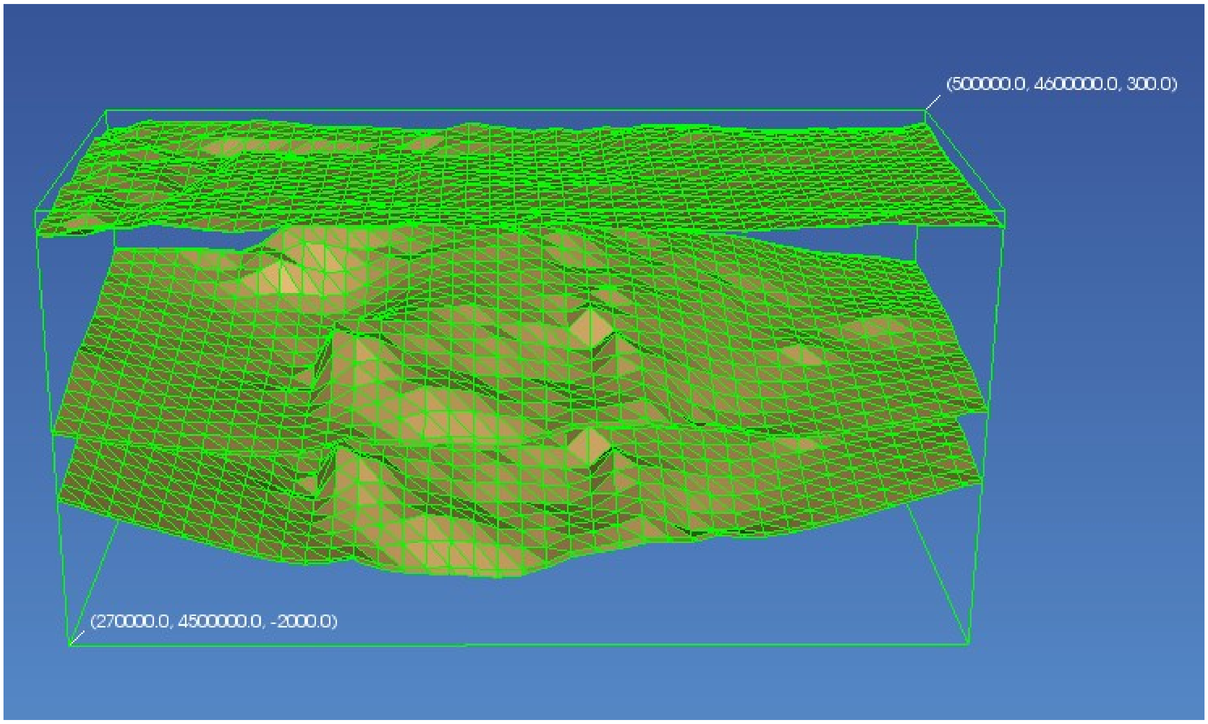


Figure 10-2. Top and bottom surfaces of Cambrian Mt. Simon sandstone and overlying Eau Claire shale defining extent of large scale TOUGH2 modeling.
Note: Rectangular map-view region corresponds to the blue-outlined region in Figure 10-1.

A 2-D TOUGH2 simulation showing CO_2 injection and storage beneath the Eau Claire is shown in Figure 10-3 (north is to the right in the figure). This model assumes isotropic and constant permeability, which oversimplifies the geologic heterogeneity and does not account for fast pathways. To do this, the analysis applies geostatistical techniques to create more realistic injection and storage scenarios.

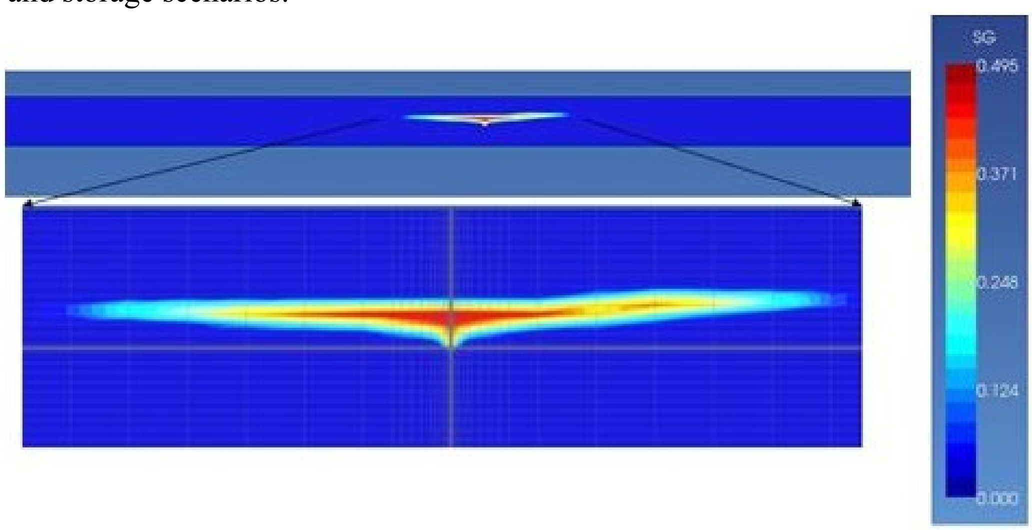


Figure 10-3. Two-dimensional TOUGH2 simulation of injection just south of small structural closure in Mt. Simon sandstone showing migration up against Eau Claire shale.

Geostatistics and Fluid Flow Modeling

Our approach to numerical modeling of injection and transport of supercritical CO_2 ($scCO_2$) in realizations of Mt. Simon Formation sandstone incorporates geostatistical methods and software, which provides tools that use limited data to describe the spatially correlated rock property values (i.e., parameters) needed for flow modeling in terms of statistics and probabilities. The subsurface is a deterministic system with unique values for parameters at points or volumes. However, the subsurface is extremely heterogeneous and sampling (e.g., via wellbores) at all locations is not possible. Furthermore, important parameters such as permeability can vary orders of magnitude within common reservoir rocks (e.g., sandstones, limestones), and the parameters can also vary with the scale of measurement (e.g., measurements made on core or via pump tests). Geostatistics provides techniques to deterministically or stochastically estimate parameters at unsampled locations. It also offers methods for quantitatively describing spatial relationships of parameters. Especially important is geostatistics' ability to provide estimates of uncertainty associated with the interpolated and extrapolated parameter values (Kelkar and Perez, 2002).

Numerical modeling of groundwater extraction from and CO_2 plume migration within the Mt. Simon Sandstone requires geostatistical approaches due to limited data for the area. The general approach uses two main steps: 1) to generate realizations (i.e., representations) of the needed flow parameter values using the standard Geostatistical software GSLIB (Deutsch and Journel, 1998) and 2) input the multiple realizations into TOUGH2 (Pruess et al., 1999) for flow modeling. Thus, the input and output to TOUGH2 is probabilistic, which allows the study to address the impact of geological uncertainty on the performance of the reservoir for coupled use (i.e., water extraction, CO_2 sequestration, and cooling of the power plant). By running multiple realizations, the analysis can derive PDF's which describe the uncertainty in storage volume (from porosity realizations) and plume migration extent (from running multiple TOUGH2 simulations). These will be used in future implementations of the WECS model to demonstrate a method to include geologic uncertainty in a systems-level economic model.

Key parameters for $scCO_2$ storage and flow modeling are porosity, permeability, and capillary pressure. The analysis is investigating the impact of spatial heterogeneity of these parameters on:

1) rates of CO_2 injection;

2) extent of CO_2 plume migration and sweep efficiency;

3) extent of the pressure perturbation due to CO_2 injection and groundwater pumping;

4) rates of groundwater production; and

5) possible breakthrough of the CO_2 at water extraction wells.

Porosity values at well locations are obtained from core and wireline logs from previous studies in the Illinois Basin by the Midwest Geological Sequestration Consortium (Finley, 2005). These data have been analyzed for their spatial correlation using auto-correlation functions or so-called variograms (Figure 10-4) which describe graphically how a property like porosity varies spatially. Using an example variogram for the upper portion or facies distributions of porosity and permeability and their correlation, the study generates multiple realizations of the porosity and permeability mapped onto a TOUGH2 grid using the geostatistical technique 'Sequential Gaussian Simulation' as included in the SGSIM program, part of the GSLIB software package (Deutsch and Journel, 1998). Permeability is obtained using the 'coregionalization' method that uses a relationship between core and wireline log porosity values and permeability measurements made on core, producing spatially correlated permeability values (Rautman and McKenna, 1997). Capillary pressure heterogeneity can be derived from the porosity and permeability fields using the Leverett 'J' function as is commonly used in petroleum engineering (Saadatpoor et al., 2007).

The analysis also performs numerical modeling for the volume of rock near to the injection and production wells using grid blocks on the order of the scale of investigation of the wireline log data (approximately 10 m × 10 m × 3 m) to investigate uncertainty on the porosity and permeability values on the five impacts listed above. According to availability, the study uses calibrated groundwater flow models and aquifer testing data (i.e., results of pump tests) to assess the appropriateness of our geostatistical representations of the parameter values.

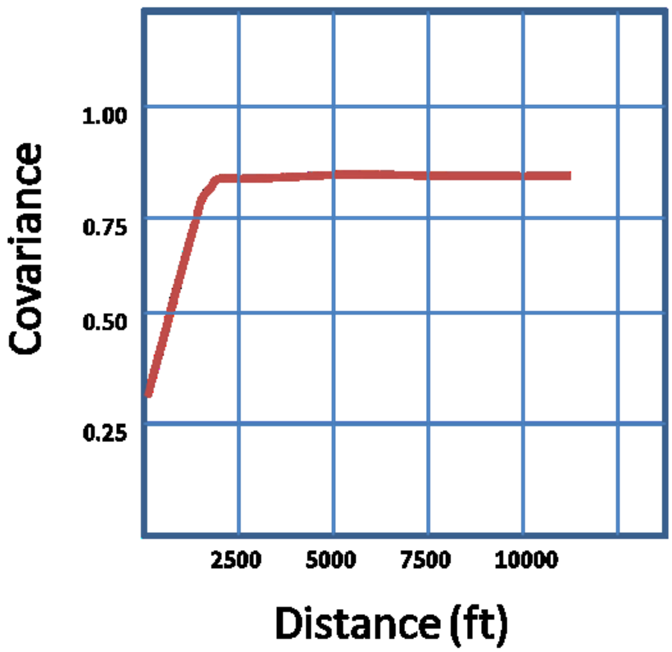


Figure 10-4. Variogram showing spatial correlation of porosity based on Mt. Simon core measurements (shown as two red lines; after Finley, 2005).
Note: A spherical modeled variogram structure is given by the red line.

A porosity realization using the above variogram, using similar methods to the study presented here, is shown in Figure 10-5 below. The realization shows that large connected regions of about 1.5 km in extent are likely, which can have a dominate effect in the direction and speed of CO_2 plume migration.

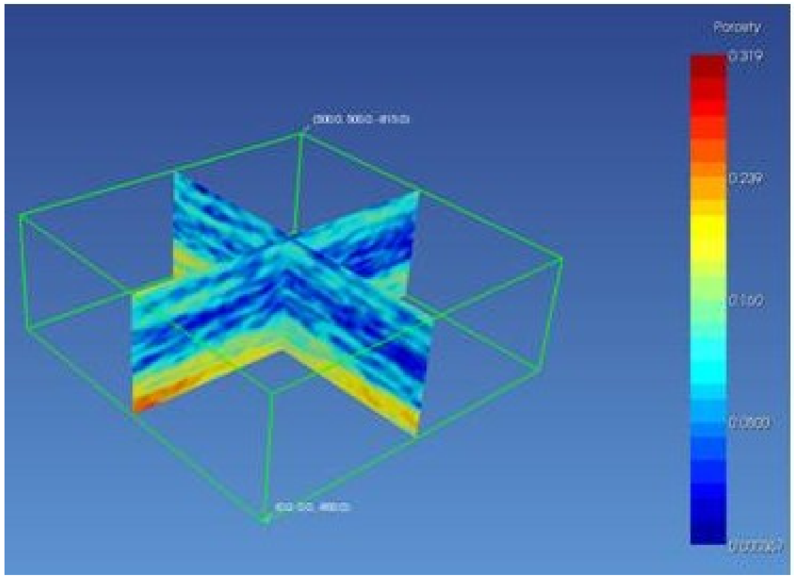


Figure 10-5. Porosity realization of Mt. Simon at Manlove Field gas injection site in NW Illinois, USA, using variogram shown in Figure 10-4 (adapted from Finley, 2005).

To examine the effect of heterogeneity on plume migration, the analysis generated 10 realizations of porosity, permeability, and capillary pressure and ran short-term (5-year) injection simulations, injecting CO_2 at a constant rate of 3.17 kg/s (~0.1 million tonnes per year). For simplicity, and to minimize simulation time, the analysis mapped 2D x-y heterogeneity onto a structured radial r-z grid, as a means for running pseudo 3D injection. The simulation domain in this set of runs is 35 m vertical by 1,000 m radial, and the top of the domain is at -815 m elevation below ground surface (Figure 10-6). An initial hydrostatic pressure gradient (0.01 MPa/m) is imposed. The injection interval is 10 1-meter cell blocks in the lower left portion (shown in yellow in Figure 10-6), and the entire right hand portion of the domain, at 1000 m, is taken to have a volume 10^5 times larger, to enable a constant pressure boundary condition while still enabling flux across the right-hand boundary. The upper and lower boundaries are closed to fluid flow. Temperature of the domain is taken to be a constant 35 degrees Celsius, and the runs are isothermal. No salinity is imposed.

Porosity, permeability, and capillary pressure distributions were mapped onto the TOUGH2 grids by defining 20 discrete intervals in the distributions, and assigning values of the midpoints of the distributions to TOUGH2 materials. The porosity and permeability values and frequency distributions from one of the realizations is shown in Figure 10-6.

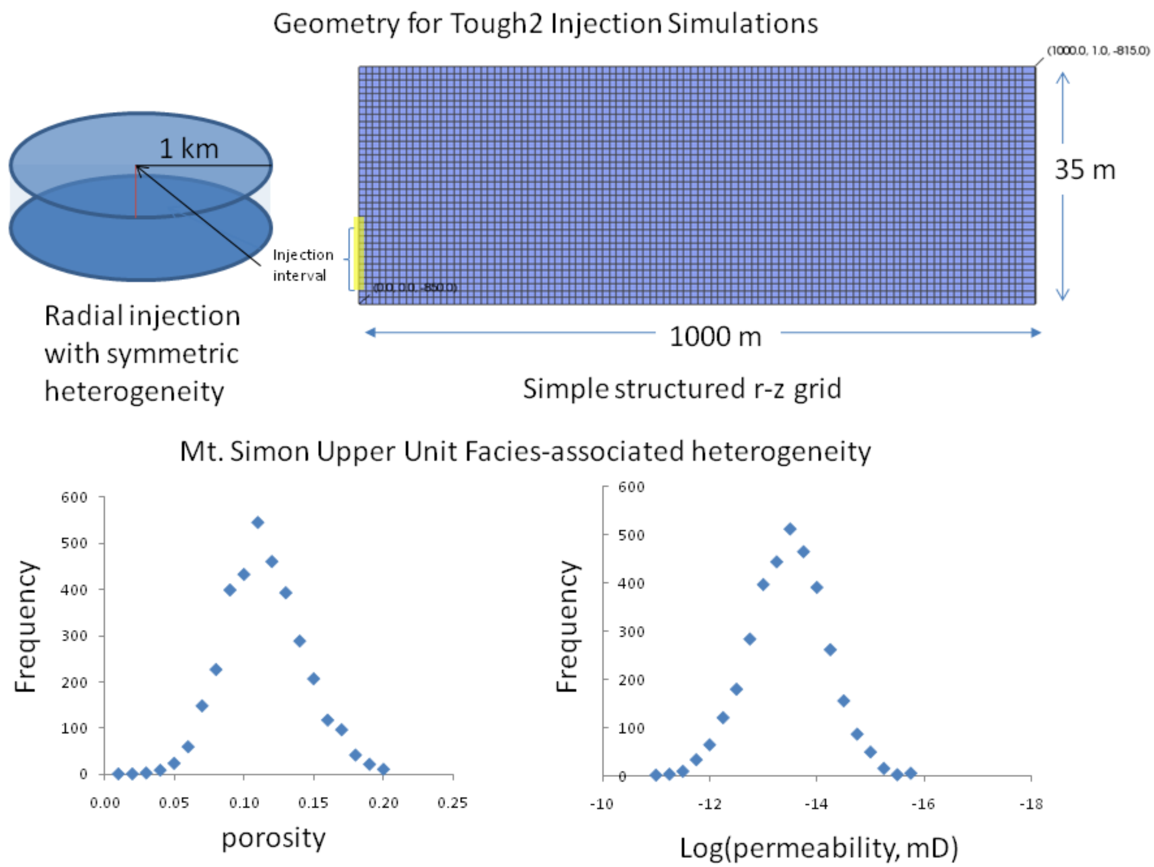


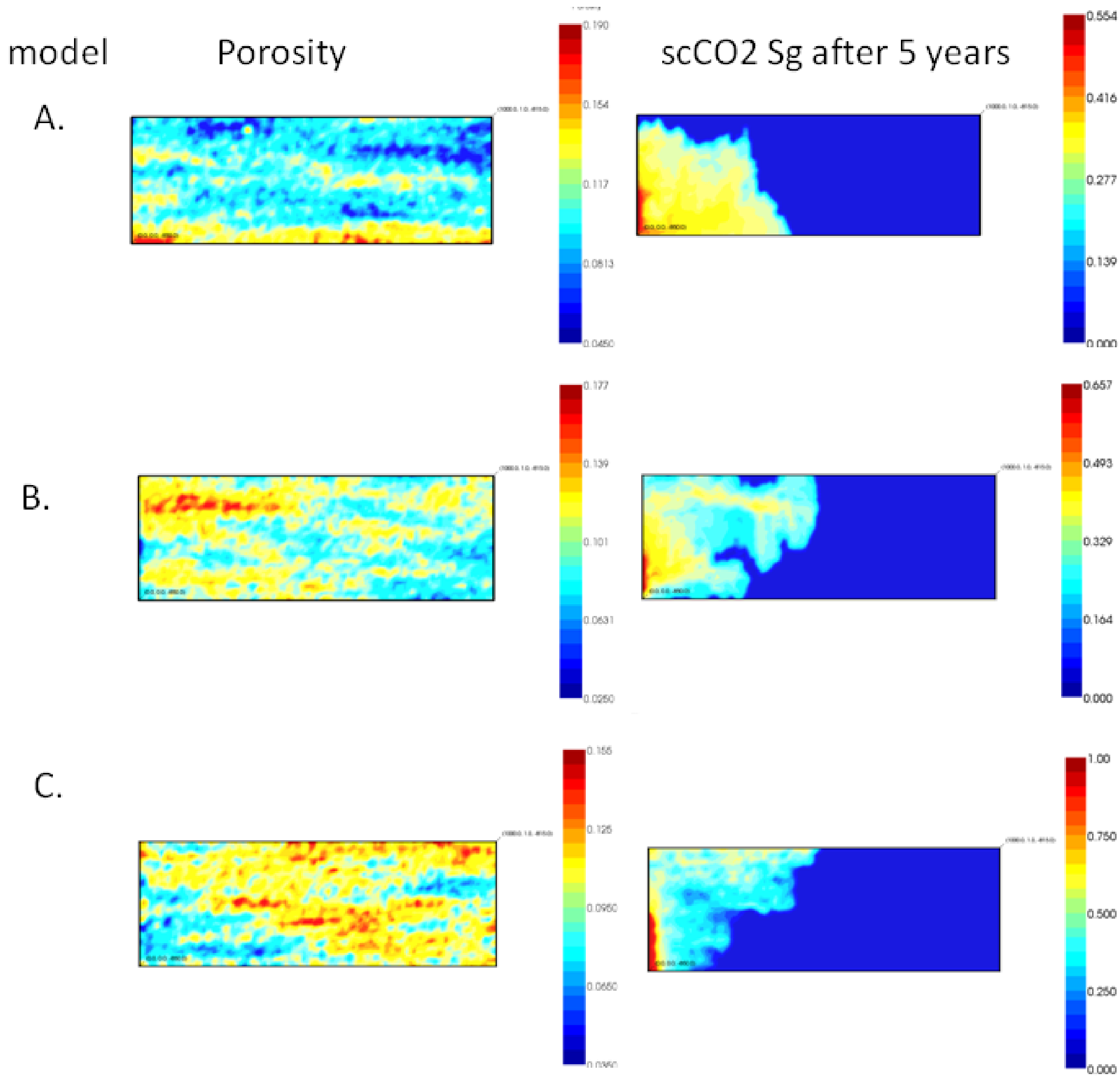
Figure 10-6. Depiction of structured r-z grid used in the TOUGH2 simulations and porosity permeability frequency distributions used in one of the TOUGH2 realizations (other realization should be nearly exactly the same).
Note: The twenty discrete points in the frequency distributions are used in the material data declarations in TOUGH2.

Spatial distributions of capillary pressure properties are included by using the Leverett-J function approach of Saadatpoor et al. (2007). The study used the Van Genuchten capillary pressure and relative permeability functions, with $\lambda = 0.457$, a residual water saturation of 0.15, and a residual gas saturation of 0.1 for all runs (S_{ls} was taken to be equal to 1.0 for all runs, additionally). Variations in the 1/Po function (the cp3 parameter in TOUGH2) were calculated using the Leverett-J correlation from the value of 4.21e-4 Pa^{-1} at the mean value of porosity and permeability. Although this is how the analysis included heterogeneity in capillary pressure for the subsequent runs, a perhaps better method is to calculate variations in residual water saturation using the Leverett-J values, keeping all other Van Genuchten parameters the same. This is not discussed further here, but this can be shown to be a better representation in the variations in capillary pressure curves from experimental data, where porosity and permeability variations are due to clay (and thus the variations in residual water saturation are linked physically to variations in clay content). Earlier simulations showed that TOUGH2 had convergence problems when using this approach.

Porosity distributions and gas saturation profiles for the ten realizations are shown in Figure 10-7A-J. The modeled CO_2 plumes have strikingly different forms for the different realizations, and all of the plumes bear little resemblance from the typical ‘gravity override’ plume shape shown in Figure 10-3. For example, in Figure 10-7A, the highest porosity and permeability (given by the warm colors) occupy a zone at the bottom of the simulation domain. Subsequently the plume has an inverted profile from that seen in Figure 10-3. Figure 10-7E has a 'fast pathway' at the very top of the simulation domain, and subsequently the $scCO_2$ saturation profile is the most like the Figure 10-3 plume.

There is a range in the lateral extent of the plume migration for the different realizations, but perhaps the most striking differences involve the sweep efficiency. Realizations in Figures 10-7 G, I, and J have heterogeneities that yield fairly dense sweep efficiencies, compared to those in Figure 10-7 C, E, and F, which have rather poor sweep efficiencies.

A distribution of plume extent derived from the ten realizations is given in Figure 10-8. The shape of the distribution has a skewed, almost log-normal appearance, and interestingly appears to be bounded on the lower end by a simple cylindrical solution, and by the Nordbotten et al. (2005) gravity override solution at the upper end. It would appear, preliminarily, that including variability in plume extent in a WECS-type model might involve calculating the cylindrical and Nordbotten-solutions, which increase with square root of time, and determining plume extent probabilistically with a log-normal shaped PDF. This possibility will be explored in future work, and would require multiple, perhaps 100, realizations to generate a statistically viable PDF for use in WECS.


model
Porosity
scCO2 Sg after 5 years
A.
B.
C.
0.190
0.154
0.117
0.0813
0.0450
0.554
0.416
0.277
0.139
0.000
0.177
0.139
0.101
0.0631
0.0250
0.657
0.493
0.329
0.164
0.000
0.155
0.125
0.0950
0.0650
0.0350
1.00
0.750
0.500
0.250
0.000

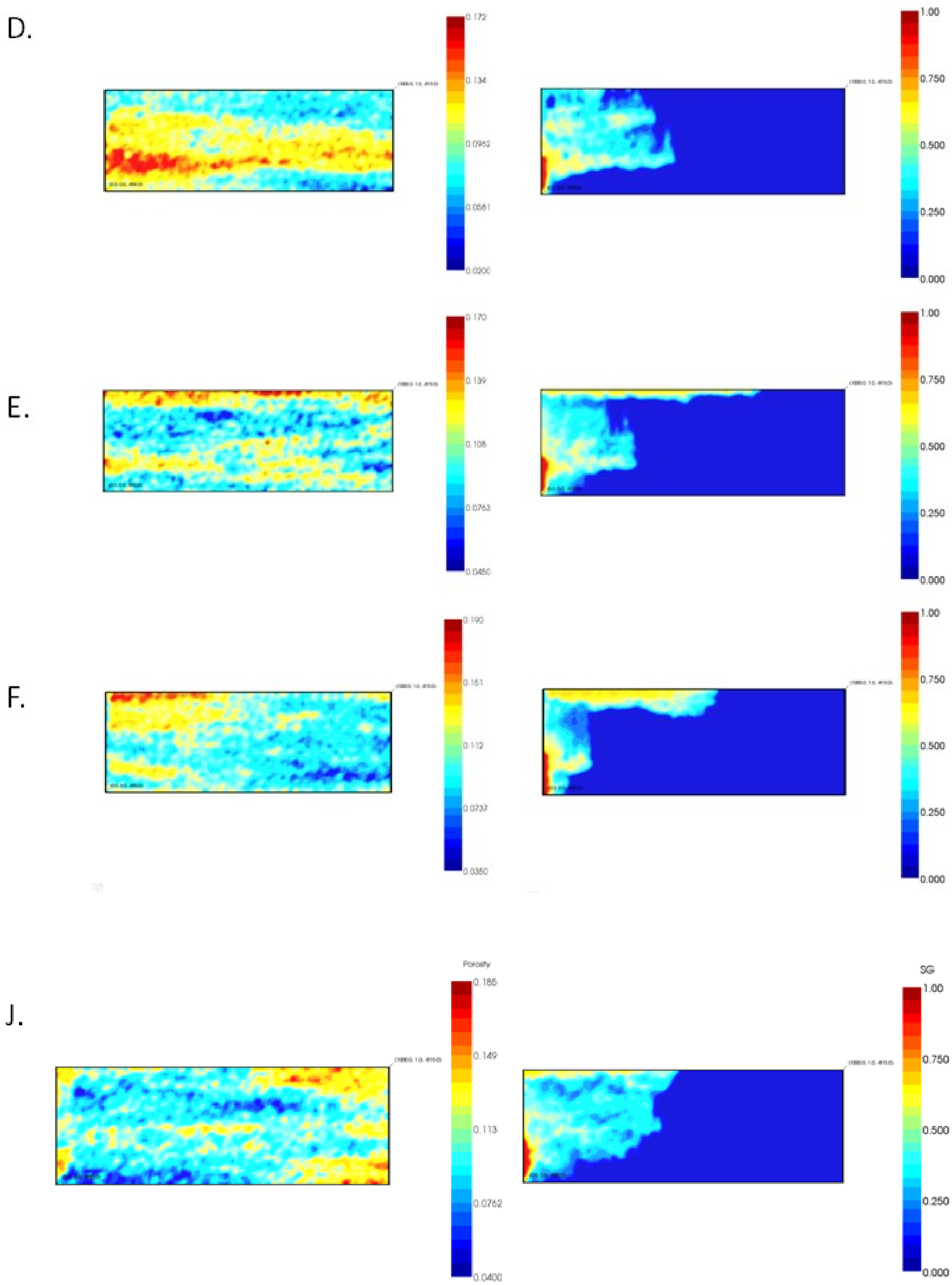


Figure 10-7. A-J Porosity distributions and $scCO_2$ saturation profiles in radial injection scenarios, using porosity, permeability and capillary pressure heterogeneity calculated using a geostatistical approach described in the text.

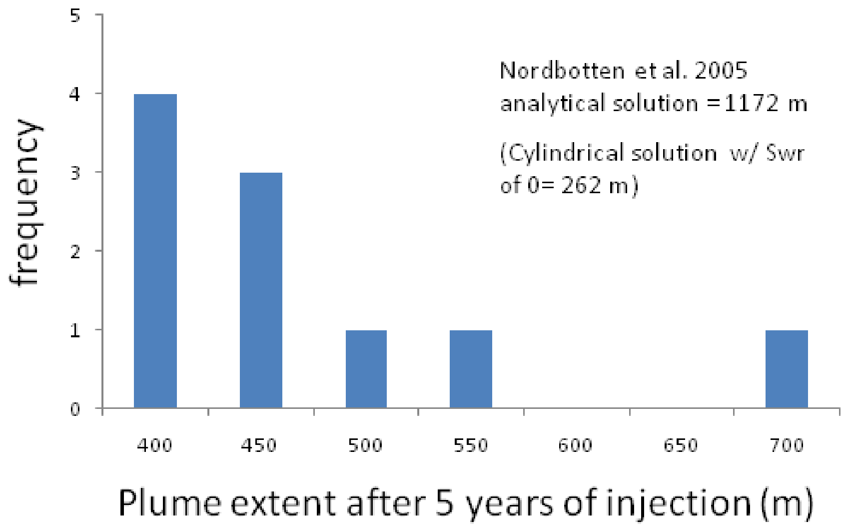


Figure 10-8. Frequency distribution of plume extent after 5 years of injection at a constant rate of 3.1 kg/s, determined from the ten realizations given in Figure 10-7.
Note: The distribution has a log normal shape, and is bounded at the upper and lower ranges by analytical solutions.

Figure 10-9 shows an interesting case where a higher porosity/permeability zone 'pinches out', and an initial fast pathway for CO_2 migration after 6 years, and resultingly poor sweep efficiency, results in a more homogeneous distribution of CO_2, with much better sweep efficiency, with sufficient time. This shows that sweep efficiency depends strongly on injection volume, and if plume extent is on the order of the spatial extent of fast pathways, heterogeneity in reservoir properties may be such that sweep efficiency improves at large times.

Future modeling efforts will be directed toward constructing PDF's in plume migration, sweep efficiency, and injectivity using the above geostatistical approach. The above work has shown the importance of considering scale-effects on these parameters and the resulting PDF's to include in upcoming versions of the WECS model. With this PDF information, the WECS model framework will be able to more fully address how ranges of local saturation of CO_2 in the formations may affect the system economics, number of wells potentially required, and storage capacity for saline formations.

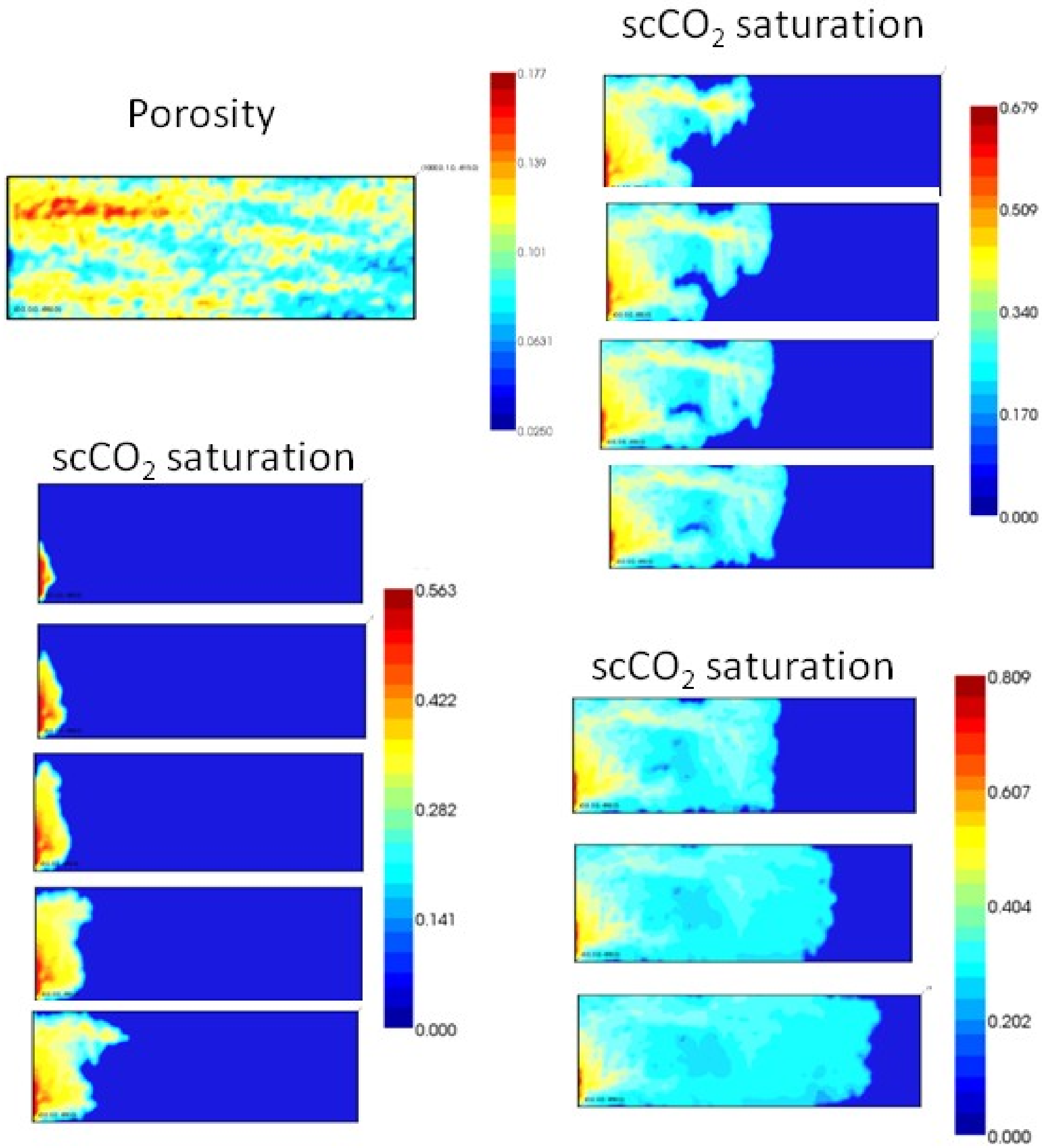


Figure 10-9. CO_2 injection and variations in sweep efficiency annually with time, up to 12 years, in a 2D simulation.

11. Future Work and Phase III Central Conclusions

The initial results of the analysis indicate that less than 20% of all the existing complete saline formation well data may meet the working depth, salinity and formation intersecting criteria. These results were taken from examining updated NatCarb data. This finding, while just an initial result, suggests that the combined use of saline formations for CO_2 storage and extracted water use may be limited by the selection criteria chosen. A second preliminary finding of the analysis suggests that some of the necessary data required for this analysis are not present in all of the NatCarb records.

This type of analysis represents the beginning of the larger, in depth study for all existing coal and natural gas power plants and saline formations in the U.S. for the purpose of potential CO_2 storage and water reuse for supplemental cooling. Additionally, this allows for potential policy insight when understanding the difficult nature of combined potential institutional (regulatory) and physical (engineered geological sequestration and extracted water system) constraints across the United States. These scenarios for all power plants and saline formations throughout U.S. can incorporate new information as it becomes available for potential new plant development planning.

As described in Section 9, one of the next steps after reducing the formations to those that may be suitable for analysis by the WECS II model is to populate information for all of the formations for the following characteristics: 1) CO_2 capacity, 2) depth to top of formation, 3) formation thickness, 4) porosity, 5) pore volume, 6) pressure, 7) temperature, and 8) salinity. Permeability will be determined from a porosity-depth relationship and porosity-permeability correlations that are dependent on the saline formation's environment of deposition, and build from the PDFs discussed earlier for the next version of the model. A reduction of 3 formations was made as they had multiple features (6 polygons). The features were merged together, and surface areas and CO_2 capacities were added together. The final working database was reduced to 325 formations from 328 as described in earlier project reports. This discussion pertains to the statistics of the input data.

Early efforts that were made to gather as much information from each regional partnership, which included geospatial data as well as reports published by the partnerships describing characterization activities. This dataset was examined to try and account for missing information for the eight characteristics that will be used to enhance inputs and decisions made in the WECS II model.

In topics in the NatCarb database where the data are missing or incomplete, relationships between depth, porosity, temperature and pressure will be analyzed to determine whether existing data from other sources can be used to supplement this missing data. In some cases, there may not be enough data. In these cases, the WECS II model will inform the user of this issue, which will then allow for them to manually enter this information if the data becomes available or the user has additional knowledge of the formation characteristics.

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Appendix A. Simplified Geospatial Representation of Potential Sequestration Formations

Problem

Powersim Studio 8 (Powersim), the software we are using to develop the WECS II model, does not have strong geospatial data representation abilities. To represent 2-dimensional geospatial data in the WECS model, the study simplifies any shape to nine points: a centroid, and eight points around the centroid at the cardinal and ordinal directions. The eight points surrounding the centroid are referred to as 'rose points' throughout this appendix because they are defined by the compass rose. This appendix describes the process used to simplify the polygons from the NatCarb database for use in Powersim.

NatCarb Database

The NatCarb saline formation geospatial database was the original source of the data for this process. The original database has approximately 10,000 saline formation 'features', which were reduced into a total of 325 individual polygon features. Many of the formations in the original dataset were broken up by state line, and others represented gridded datasets that could be scaled up to saline formations that are more easily analyzed. This reduction did not change substantially with respect to the available polygons in the dataset, it just made the data more accessible for this analysis which was restricted to the continental U.S.

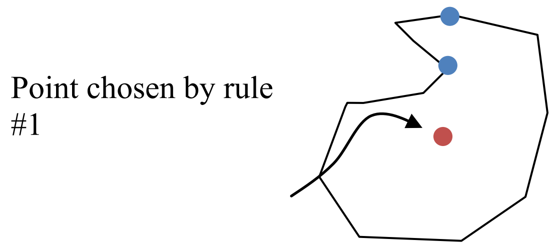
After processing the data into the 325 individual formations, an ArcGIS function was used to export the centroids of each polygon to an excel file with a corresponding unique ID. A different function was used to convert each formation polygon into a set of points using the vertices that define the shape of the polygon. This dataset was also exported to Excel and has a unique ID that matches the centroids unique ID.

An exhaustive search of functions and tools in ArcGIS was conducted to take the centroid of the polygon and extended out to find the points on the polygon in eight cardinal/ordinal directions that roughly define its shape. There was not a function available to process the data in an automated fashion so the decision was made to use Matlab for determining the point coordinates.

Simplification of the Shapes

Matlab was used to process the different points generated by the GIS process described in the previous section. Those points are referred to as border points here. The number of border points generated by the GIS process for each shape varied from a minimum of 8 to a maximum of 20,723. To handle the shapes defined by a small number of points, a fairly robust process was needed. The following rule was adopted:

1. Find the point within +-x degrees of the desired direction that is furthest from the centroid. The idea here is to try and capture some of the waviness of a figure, or areas where a figure may double back. For example, consider the following figure in which the red point is the hypothetical centroid, and the blue points are both within x degrees of north of the centroid. For the simplified shape, we want to take the point further from the centroid.



2. If there is no point within +-x degrees of the direction in question, find the point closest to the direction in question within +-y degrees.

3. If there is no point within +-y degrees of the direction, choose the centroid. This rule ends up being applied in situations where the border points are very sparse, or the centroid is actually external to the shape. Initially, only internal centroids were used, but the results were less satisfying than when using external centroids and allowing the centroid to act as a selected point, essentially meaning the shape would not extend at all in that direction.

4. The distances of the selected points were then calculated, and used as the distances from the centroid to the edge of the shape in the 8 cardinal and ordinal directions, which defines the simple shape.

These rules were implemented in Matlab, and applied to the 325 formation shapes from the NatCarb database. The parameters ‘X’ and ‘Y’ are referred to as tolerance and sweep, and do influence the resulting shapes created in this process. Visual trial and error resulted in the use of 7.5 and 30 degrees for tolerance and sweep, respectively. In general, the more round a shape, the better this process works, and the more long and thin, the less accurate the process becomes. Some representative shapes and their simple shape equivalents are shown below. The eight points chosen are called the rose points from the idea of a compass rose. Similar figures are available for all of the 325 formations used.

The areas of the simplified shapes are compared to the areas of the GIS shapes in Figure A-4 below, and the distribution of percent error is shown in Figure A-5. As can be seen in Figure A-4, the overall agreement is good, and there is not any overall bias to area resulting from simplification in this manner. As can be seen from Figure A-5, the simplified area is within 10% of the GIS area for 44% of the shapes, within 20% for 72% of the shapes, and within 30% for 86% of the shapes. Considering the uncertainty associated with delineation of these deep saline aquifers to begin with, these results are acceptable for the purposes of this study, and show that simplification can occur without a substantial loss of information needed for a systems level analysis of the formations.

The end result of this process is 8 distances for each of the 325 formations being considered. These distances, together with a centroid, represent the approximate size of a saline formation in the NatCarb database, and one to be considered in the WECS II model. This simple geospatial representation is data light and easily implemented in Powersim, and though it does represent a loss of information, the magnitude of this information loss from the perspective of a national scale systems model is thought to be well within the error associated with the original data. For each formation, Table A-1 shows the simplified geometry used by the WECS II model including the latitude and longitude of the centroid point and the distance from that point to the edge of the formation in each of the cardinal and ordinal directions. Figures A-1 through A-5 and Table A-1 occupy the remainder of this appendix.

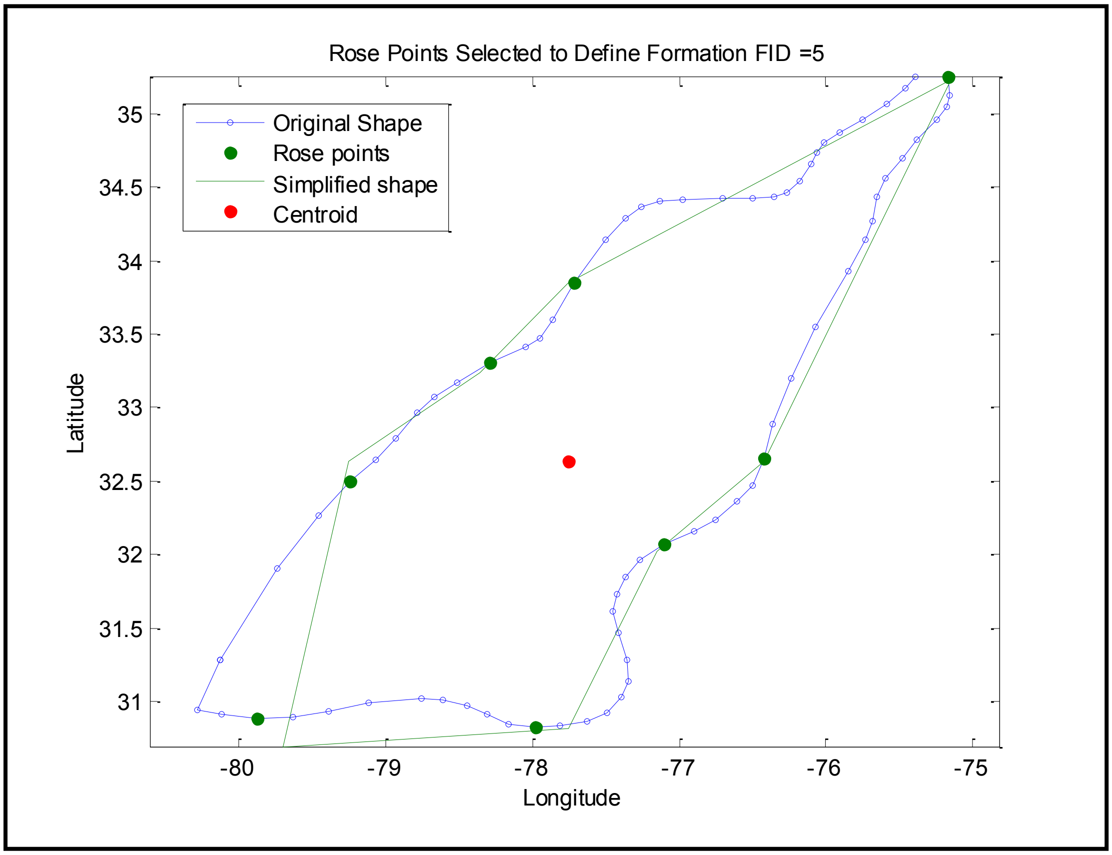


Figure A-1. The rose points and simplified shape for the formation with FID=5.
Note: This simplification worked reasonably well, except in the bottom left corner due to the extent of the bulge is north of SW.

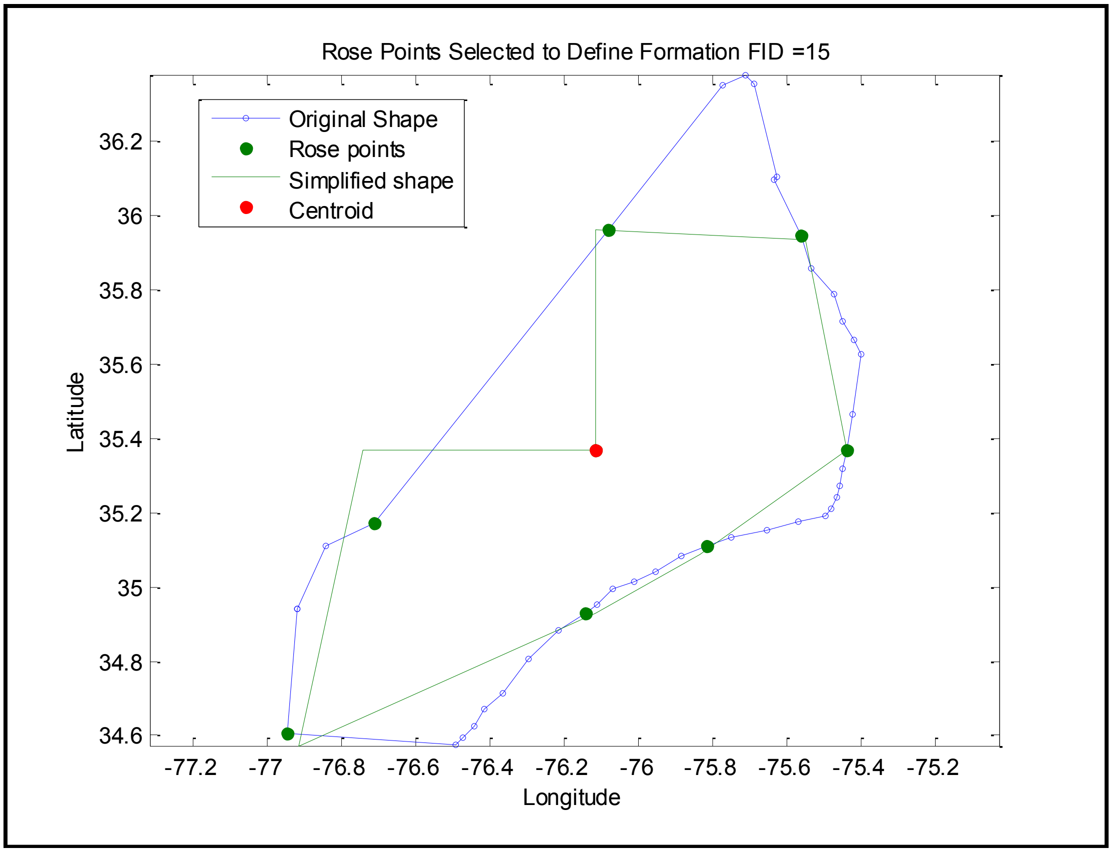


Figure A-2. The rose points and simplified shape for the formation with FID=15.
Note: This is an example of a shape for which the simplification worked poorly due to a lack of points generated by the GIS routine to define the original shape. This shape shows the results where a lack of points in the NW sweep resulted in the use of the centroid for that rose point. A higher tolerance (x) parameter would result in the points at the top of the original shape being selected for the N and NE directions, and thus a larger simplified shape, but not necessarily a more accurate simplification.

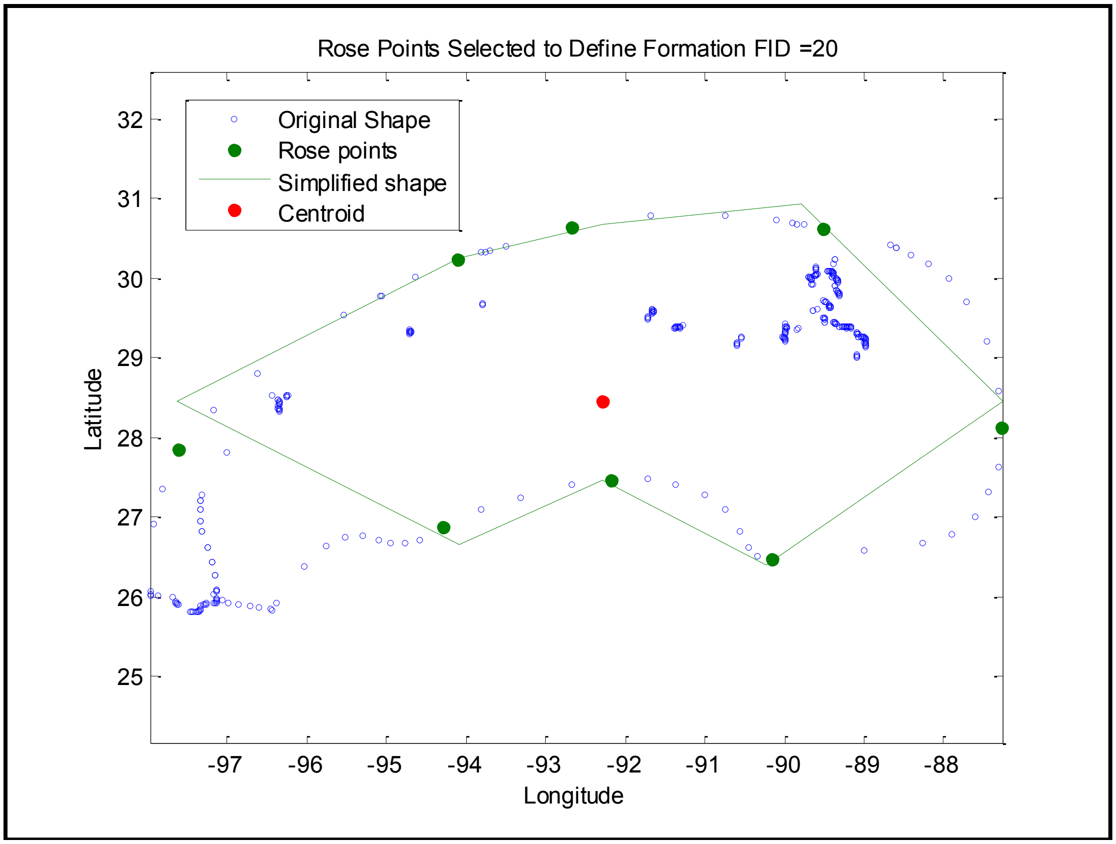


Figure A-3. The rose points and simplified shape for the formation with FID=20.
Note: From an absolute area perspective, this is the worst simplification of the ones illustrated in this report, with the simplified shape 31,000 square miles smaller than the GIS shape (see Figure A-4). However, from a percent error perspective, the simplification represents a more reasonable 22% reduction in area. The reason for border points internal to the overall shape is not readily apparent from using this technique.

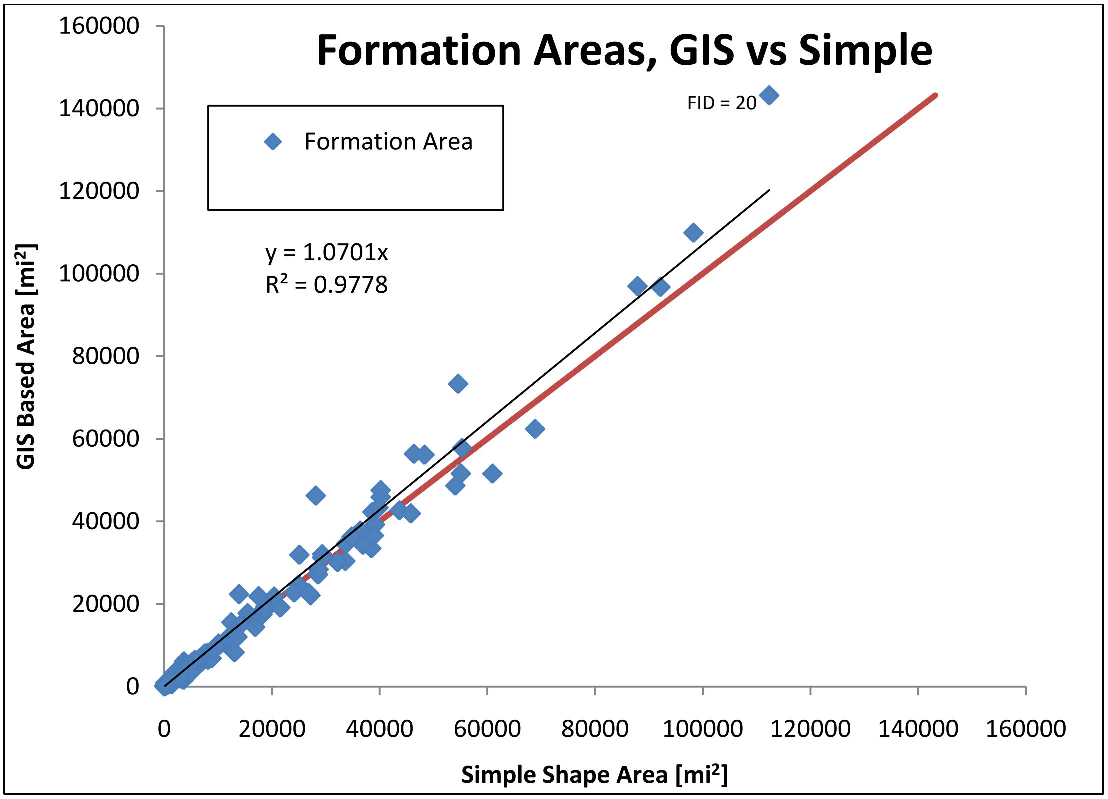


Figure A-4. Scatter plot comparison of the area of the simplified shape compared to the area of the GIS polygon of the original formation.
Note: The overall agreement is good, and there is not any bias to the area due to the simplification. In terms of absolute error, the worst formation is FID=20, which can be seen in Figure A-3.

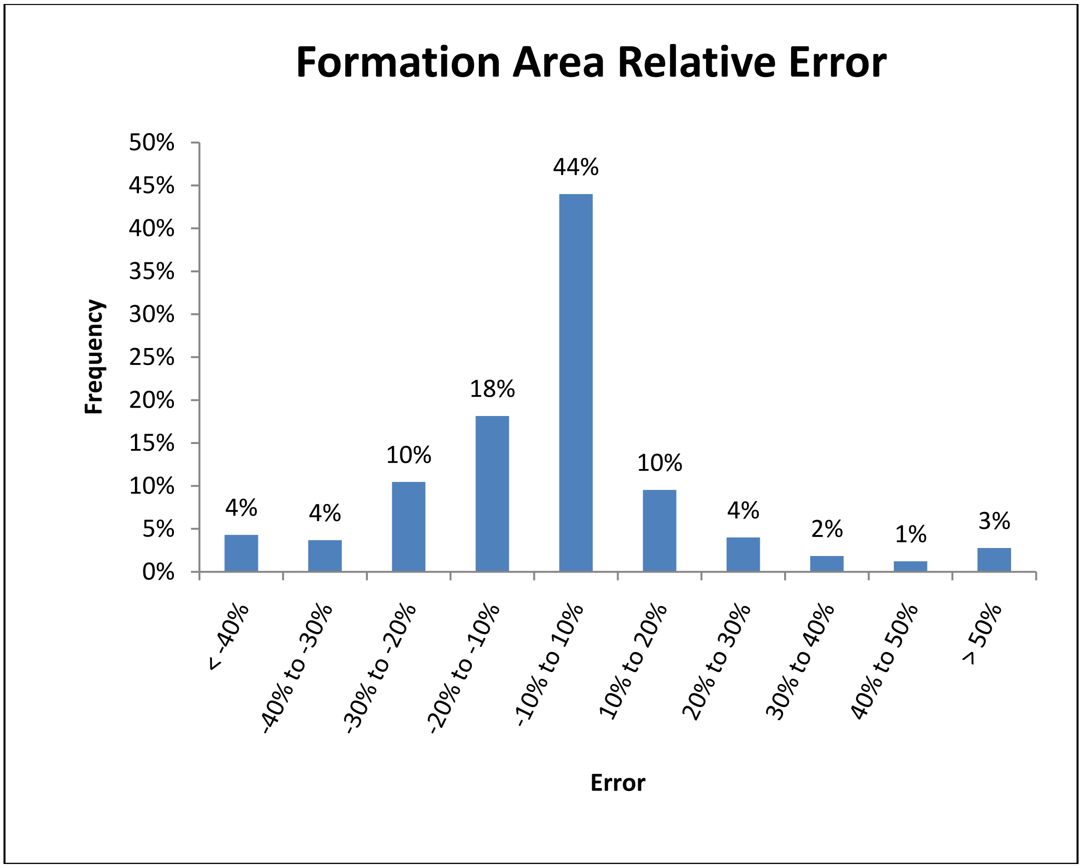


Figure A-5. Histogram of the relative error using the area simplification technique.
Note: Only 14% of shapes have a relative error greater than +-30%.
The simplified area is within 10% of the GIS area for 44% of the shapes, within 20% for 72% of the shapes, and within 30% for 86% of the shapes. Considering the uncertainty associated with delineation of these deep saline aquifers to begin with, these results are acceptable.

Table A-1. The coordinates used in WECS II to define the simplified representation of the spatial footprint for sequestration formations.
Note: There are 325 formations which in this table are identified by their regional carbon sequestration partnership, basin and formation names applied in some circumstances by the partnerships as well as a unique identifying field called FID that spans from 0-324.

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
				Long	Lat	N	NE	E	SE	S	SW	W	NW
0	SECARB	Cedar Keys Lawson Fm	Cedar Keys Lawson Fm	-81.3373	27.2676	155	71	83	125	146	76	78	140
1	SECARB	GULF COAST	Eocene Sand	-93.8995	29.9930	116	192	446	0	0	389	253	147
2	SECARB	GULF COAST	Tertiary Undivided	-90.7107	32.7953	149	55	62	134	90	85	50	136
3	SECARB	GULF COAST	Oligocene	-94.5436	29.2844	109	174	269	0	0	322	185	100
4	SECARB	Tuscaloosa Group	Tuscaloosa Group	-89.8986	31.6843	107	87	199	139	81	78	201	143
5	SECARB	Offshore Atlantic	N/A	-77.7558	32.6304	84	236	77	54	125	173	87	56
6	SECARB	Offshore Atlantic	N/A	-78.0314	33.2898	8	110	36	13	19	141	15	0
7	SECARB	Woodbine & Paluxy Fm	Woodbine & Paluxy Fm	-95.4392	32.1206	101	123	83	89	114	128	73	96
8	MGSC	Illinois Basin	Cypress SS	-88.3603	38.3326	56	42	25	35	41	44	26	30
9	MGSC	Illinois Basin	Mt.Simon SS	-88.4385	39.2665	131	109	132	165	141	126	131	184
10	MGSC	Illinois Basin	St.Peter SS	-88.0984	38.6002	101	103	92	115	96	105	95	110
11	SECARB	GULF COAST	Olmos	-99.2641	28.5018	26	49	42	15	11	57	30	28
12	SECARB	GULF COAST	Pliocene	-91.3327	27.4016	23	52	199	82	79	105	280	26
13	SECARB	Potomac Group	Potomac Group1	-75.5656	37.8466	11	16	16	0	21	0	13	10
14	SECARB	Potomac Group	Potomac Group2OS	-75.4539	37.6499	14	32	0	0	21	12	5	6
15	SECARB	Potomac Group	Potomac Group2	-76.1163	35.3694	41	51	38	25	30	71	36	0
16	SECARB	Potomac Group	Potomac Group1OS	-75.6727	35.2288	61	34	12	15	5	65	0	0
17	SECARB	Pottsville Fm	Pottsville Fm	-89.1285	33.4923	21	11	17	49	0	0	19	37
18	SECARB	South Carolina-Georg	Triassic, Tuscaloosa	-80.6737	32.0116	51	98	99	65	103	115	103	61
19	MRCSP	Coastal Plains	N/A	-76.2379	38.7318	62	49	29	68	48	46	54	44
20	SECARB	GULF COAST	Miocene	-92.2787	28.4499	153	226	305	188	68	163	326	166
21	SECARB	Mt. Simon Ss	Mt. Simon Ss	-86.5325	35.8848	0	152	118	71	0	118	106	100
22	MRCSP	Michigan BAsin	N/A	-84.7560	43.1798	180	149	119	113	152	175	86	136
23	MRCSP	Appalachian Basin	N/A	-80.4777	40.1161	137	295	106	96	190	338	143	130
24	MRCSP	Fold and Thrust Belt	N/A	-75.6562	41.8228	210	239	113	118	148	304	41	118
25	Big Sky	Montana Thrust Belt	Imbricate Thrust Gas	-113.2479	47.9600	72	32	31	114	62	36	32	94
26	Big Sky	North-Central Montan	Jurassic-Cretaceous	-109.4042	47.5418	101	134	94	145	104	107	141	134
27	Big Sky	North-Central Montan	Shallow Cretaceous B	-109.0061	47.4923	105	135	76	156	137	72	138	138
28	Big Sky	Southwest Montana	Crazy Mountains and	-109.7513	45.8220	30	45	41	46	27	27	58	43
29	Big Sky	Southwest Montana	Nye-Bowler Wrench Zo	-109.5781	45.3447	4	3	43	9	0	0	9	7
30	Big Sky	Big Horn Basin	Deep Basin Structure	-108.4658	44.3474	21	17	21	41	28	21	19	59
31	Big Sky	Big Horn Basin	Phosphoria Stratigra	-107.9138	44.1431	45	6	6	15	43	11	9	16
32	Big Sky	Wind River Basin	Basin Margin Subthru3	-109.3774	43.6323	4	3	7	13	5	4	6	11
33	Big Sky	Wind River Basin	Basin Margin Subthru	-107.4642	43.2405	14	14	21	54	0	0	57	19
34	Big Sky	Wind River Basin	Basin Margin Subthru2	-107.9337	42.5799	6	3	3	17	7	5	6	16

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
35	Big Sky	Wind River Basin	Basin Margin Anticli	-108.7909	43.2133	25	23	0	47	19	12	2	29
36	Big Sky	Wind River Basin	Basin Margin Anticli2	-107.9482	42.9052	8	11	32	9	8	21	26	18
37	Big Sky	Wind River Basin	Deep Basin Structure	-107.9940	43.1737	14	19	45	14	10	10	46	23
38	Big Sky	Wind River Basin	Muddy Sandstone Stra	-107.8525	42.8566	11	18	54	3	3	28	44	19
39	Southwest	Permian	Montoya	-102.5805	31.5983	128	120	77	110	83	89	124	39
40	MRCSP	Arches Province	N/A	-84.8345	39.7563	93	167	90	125	161	91	86	141
41	Big Sky	North-Central Montan	Fractured-Faulted Ca	-109.4042	47.5418	101	134	94	145	104	107	141	134
42	Big Sky	North-Central Montan	Tyler Sandstone	-108.2406	46.4021	53	41	103	38	82	61	111	60
43	Southwest	Permian	Pennsylvanian	-102.0383	33.2089	210	130	67	97	205	151	187	128
44	Southwest	Permian	San Andres	-101.9423	32.5569	133	113	61	102	142	107	65	91
45	Southwest	Permian	Siluro-Devonian	-102.8225	31.5636	179	112	107	139	82	146	133	34
46	Big Sky	Wyoming Thrust Belt	Hogsback Thrust	-110.6031	41.6312	59	22	10	11	47	21	4	6
47	Big Sky	Wyoming Thrust Belt	Cretaceous Stratigra	-110.6823	41.5196	26	12	5	5	25	13	3	2
48	Big Sky	Southwestern Wyoming	Rock Springs Uplift	-108.8878	41.6353	36	24	30	19	34	32	20	29
49	Big Sky	Southwestern Wyoming	Cherokee Arch	-108.2428	40.9796	6	8	42	9	0	11	40	7
50	Big Sky	Southwestern Wyoming	Moxa Arch-LaBarge	-110.1237	41.8742	48	24	9	16	59	10	5	23
51	Big Sky	Southwestern Wyoming	Basin Margin Anticli	-109.0919	42.5470	0	0	82	33	21	18	71	72
52	Big Sky	Southwestern Wyoming	Basin Margin Anticli2	-110.3688	41.4326	50	17	9	18	35	32	7	8
53	Big Sky	Southwestern Wyoming	Basin Margin Anticli3	-109.5972	40.9980	2	3	33	0	0	0	35	4
54	Big Sky	Southwestern Wyoming	Basin Margin Anticli4	-108.6276	40.7968	6	2	2	14	4	3	5	11
55	Big Sky	Southwestern Wyoming	Platform	-106.5384	41.6384	42	55	55	61	15	75	51	59
56	Big Sky	Williston Basin	Madison (Mississippi	-104.5840	47.1414	129	53	26	166	133	59	72	172
57	Big Sky	Williston Basin	Red River (Ordovicia)	-104.5840	47.1414	129	53	26	166	133	59	72	172
58	Big Sky	Williston Basin	Middle and Upper Dev	-104.5840	47.1414	129	53	26	166	133	59	72	172
59	Big Sky	Williston Basin	Pre-Prairie Middle D	-105.2013	47.8724	78	94	55	116	90	58	60	103
60	Big Sky	Williston Basin	Post-Madison through	-105.2782	48.1419	59	79	58	105	69	56	65	78
61	Big Sky	Williston Basin	Pre-Red River Gas	-104.4070	48.3314	46	34	17	34	59	26	17	55
62	Big Sky	Powder River Basin	Basin Margin Anticli	-106.0889	43.8913	0	0	108	117	86	70	35	170
63	Big Sky	Powder River Basin	Leo Sandstone	-105.1007	43.4328	50	49	46	33	49	51	48	34
64	Big Sky	Powder River Basin	Upper Minnelusa Sand	-105.7158	44.4247	63	78	45	54	102	59	54	55
65	Big Sky	Powder River Basin	Lakota Sandstone	-105.6363	44.4021	96	81	51	101	110	64	65	109
66	Big Sky	Powder River Basin	Fall River Sandstone	-105.2893	44.1745	111	71	43	78	100	97	20	106
67	Southwest	Permian	Simpson	-102.7716	31.2862	100	77	89	116	62	73	122	101
68	Big Sky	Wind River Basin	Shallow Tertiary - U	-107.9607	43.1010	18	25	47	18	16	34	47	32
69	Big Sky	Wyoming Thrust Belt	Moxa Arch Extension	-110.6203	42.8655	26	5	4	11	27	5	4	9
70	Big Sky	Wyoming Thrust Belt	Absaroka Thrust	-110.9611	41.5692	65	39	15	15	48	67	8	8
71	Big Sky	North-Central Montan	Devonian-Mississippi	-109.4467	47.5186	103	136	97	143	102	105	140	135

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
72	Southwest	Permian	San Andres Limeston	-103.6388	32.9047	42	52	36	32	45	43	40	35
73	Southwest	Permian	Triassic	-102.1159	32.6641	141	111	86	92	143	120	110	129
74	Southwest	Permian	Upper_Guadalupe	-102.4144	31.9682	130	130	89	127	98	112	139	94
75	Southwest	Permian	Wolfcamp	-101.9468	33.5588	187	100	68	114	215	136	0	136
76	Southwest	Permian	Morrison Formation	-103.5566	32.9395	45	47	32	55	39	36	47	48
77	Big Sky	Powder River Basin	Muddy Sandstone	-105.6426	44.3703	98	83	53	100	113	62	64	110
78	Big Sky	Powder River Basin	Deep Frontier Sandst	-105.6169	43.3786	30	31	37	55	42	30	21	89
79	Big Sky	Powder River Basin	Turner Sandstone	-104.7192	43.6919	38	26	30	35	44	23	28	39
80	Big Sky	Powder River Basin	Sussex-Shannon Sands	-105.9105	44.1292	72	37	44	83	88	36	27	93
81	Big Sky	Powder River Basin	Mesaverde-Lewis	-105.9138	43.9760	76	36	22	97	75	26	33	99
82	Southwest	Navajo Power Plant	CEDAR MESA SANDSTONE	-111.3733	36.8173	9	7	9	7	6	8	10	4
83	Southwest	Cholla Power Plant	NACO	-110.3056	34.9354	8	8	7	7	7	7	7	8
84	Southwest	St. Johns-Springervi	GRANITE WASH	-109.1977	34.3262	7	5	5	14	7	0	6	13
85	Southwest	Willcox basin	TERTIARY BASIN FILL	-109.8508	32.2086	14	5	5	16	17	8	6	16
86	Southwest	Red Rock basin	TERTIARY BASIN FILL	-111.2795	32.5391	21	2	3	9	20	7	6	7
87	Southwest	Higley basin	TERTIARY BASIN FILL	-111.7246	33.3059	8	7	12	10	6	9	10	10
88	Southwest	Luke basin	BASIN FILL-EVAPORITE	-112.2978	33.5235	9	5	12	11	9	8	9	13
89	Southwest	Tucson basin	TERTIARY EVAPORITES-	-110.8735	32.0036	18	12	10	7	14	18	4	10
90	Southwest	Mohawk basin	TERTIARY BASIN FILL	-113.8296	32.6050	11	6	8	14	11	8	7	15
91	Southwest	San Cristobal basin	TERTIARY BASIN FILL	-113.5463	32.6577	8	5	6	16	5	4	5	14
92	Southwest	Navajo Power Plant	REDWALL LIMESTONE	-111.3733	36.8173	9	7	9	7	6	8	10	4
93	Southwest	Navajo Power Plant	TAPEATS SANDSTONE	-111.3733	36.8173	9	7	9	7	6	8	10	4
94	Southwest	Permian	Ellenburger	-102.4222	31.9179	167	148	89	154	117	150	132	55
95	Southwest	Permian	Leonard	-102.3314	31.9810	140	139	85	138	104	118	142	84
96	Southwest	Permian	Mississippian	-101.9963	32.5604	159	132	66	91	158	113	109	85
97	Southwest	Permian	Devonian strata	-103.4236	33.0881	74	70	12	50	77	49	38	60
98	Southwest	Denver	Lyons	-103.8946	40.0406	122	134	76	92	146	100	72	114
99	Southwest	Denver	Morrison	-103.7357	40.5110	154	104	91	92	144	115	77	112
100	Southwest	Raton	Carlile	-104.9552	37.1587	37	21	18	31	40	27	16	31
101	Southwest	Raton	Dockum	-104.8545	37.2025	26	13	13	20	23	20	0	29
102	Southwest	Raton	Forthayes	-104.9911	37.2182	37	15	23	24	36	27	15	32
103	Southwest	Raton	Glorieta	-104.7053	37.1048	34	18	23	24	35	22	15	33
104	Southwest	Raton	Codell	-104.9904	37.4119	24	19	3	40	24	12	12	32
105	Southwest	Raton	Raton	-105.0276	37.4756	5	4	2	3	4	4	2	1
106	Southwest	Raton	Graneros	-104.9423	37.1911	40	24	29	32	39	33	22	40
107	Southwest	Raton	Dakota	-104.9068	37.1778	40	19	26	34	40	32	17	43
108	Southwest	Raton	Entrada	-104.9112	37.1758	42	26	32	32	41	34	18	44
109	Southwest	Raton	Sangre De Cristo	-104.9209	37.1270	41	21	32	33	42	31	20	43

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
110	Southwest	Raton	Yeso	-104.6147	37.2097	13	12	23	29	15	15	21	30
111	Southwest	Raton	Greenhorn	-104.9497	37.1736	41	21	23	35	40	31	19	40
112	Southwest	Raton	Morrison	-104.9211	37.1789	43	20	28	35	42	34	20	44
113	Southwest	Raton	Pierreshale	-105.0037	37.4480	12	5	3	5	13	4	5	6
114	Southwest	Raton	Purgatoire	-104.9303	37.2169	34	19	26	31	30	27	19	36
115	Southwest	Anadarko	Chester	-102.3483	37.3775	41	22	16	31	27	30	24	6
116	Southwest	Raton	Smoky Hill Marl	-104.9401	37.3221	22	3	2	4	17	5	3	4
117	Southwest	Anadarko	Arbuckle	-102.5242	37.5575	48	26	21	40	33	46	29	26
118	Southwest	Anadarko	Atoka	-102.4314	37.6089	44	35	21	33	43	38	28	34
119	Southwest	Raton	Trinidad	-104.9690	37.3637	3	2	2	12	11	5	3	10
120	Southwest	Uinta	Dakota	-109.9604	39.7916	16	46	51	31	15	11	68	23
121	Southwest	Anadarko	Desse/Cherokee	-102.4086	37.6148	46	35	20	40	43	47	23	35
122	Southwest	Anadarko	Misener	-102.4170	37.6472	25	23	15	11	13	31	20	20
123	Southwest	Anadarko	Morrow	-102.4779	37.5818	48	45	24	46	41	51	32	23
124	Southwest	Anadarko	Simpson	-102.3252	37.6278	36	10	13	20	34	1	1	2
125	Southwest	Anadarko	Viola	-102.4778	37.7317	34	40	16	35	15	34	28	24
126	Southwest	Uinta	Entrada	-109.8025	39.7945	53	49	39	37	17	16	75	0
127	Southwest	Uinta	Frontier2	-109.5709	40.4483	5	4	4	6	5	3	5	6
128	Southwest	Uinta	Green River	-110.0550	40.2887	23	21	48	34	21	22	48	25
129	Southwest	Uinta	Frontier1	-109.2412	39.7514	37	22	13	20	23	28	10	0
130	Southwest	Uinta	Mancos	-109.8359	39.9556	43	33	44	48	29	27	59	52
131	Southwest	Uinta	Uinta1	-110.1259	40.4243	10	11	15	8	7	10	14	8
132	Southwest	Uinta	Kayenta	-110.8230	39.5575	8	10	24	7	7	9	22	9
133	Southwest	Uinta	Mesaverde	-109.8340	40.0113	37	31	42	41	30	30	46	34
134	Southwest	Uinta	Sego	-109.3916	40.4089	9	3	4	6	5	5	8	6
135	Southwest	Uinta	Uinta2	-109.4825	40.2582	5	4	6	8	4	5	7	7
136	Southwest	SanJuan	CliffHouse	-107.5372	36.6718	44	36	37	53	37	32	44	41
137	Southwest	Uinta	Wasatch	-109.9862	40.0868	30	29	49	35	37	35	65	32
138	Southwest	Uinta	White Rim/Coconino	-110.8519	39.5372	3	3	25	6	5	6	18	7
139	Southwest	SanJuan	Chinle	-108.0805	36.3269	9	10	69	5	5	71	26	62
140	Southwest	SanJuan	DeChelley	-108.4506	36.5623	33	25	49	32	36	25	35	45
141	Southwest	SanJuan	Entrada	-107.7120	36.4098	68	60	58	69	91	43	55	63
142	Southwest	SanJuan	Dakota	-107.7213	36.4886	59	60	54	63	61	57	55	60
143	Southwest	SanJuan	Elbert	-108.6438	36.7345	18	50	22	25	31	29	24	27
144	Southwest	SanJuan	Leadville	-108.1109	36.7240	40	39	43	22	26	38	51	25
145	Southwest	SanJuan	HonakerTrail	-108.3284	36.8424	38	34	38	7	8	47	29	10
146	Southwest	SanJuan	Fruitland	-107.3815	36.7212	39	21	23	45	27	18	20	45
147	Southwest	SanJuan	Lewis	-107.4356	36.7370	32	22	28	47	28	17	30	43
148	Southwest	SanJuan	Mancos	-107.7325	36.4940	45	43	44	54	34	39	54	38
149	Southwest	SanJuan	Menefee	-107.5675	36.6316	46	32	39	53	39	29	43	43
150	Southwest	SanJuan	Morrison	-107.7214	36.4563	59	59	54	64	65	61	56	64

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
151	Southwest	SanJuan	OrganRock	-108.7084	36.6307	25	14	14	39	15	22	19	27
152	Southwest	Green River	Morrison	-108.5172	41.4755	63	78	148	121	88	55	89	146
153	Southwest	Green River	Graneros	-107.8377	40.5769	15	12	24	28	18	14	16	33
154	Southwest	Green River	Fort Hays	-108.0562	40.8769	15	11	17	49	23	15	18	47
155	Southwest	SanJuan	Ouray	-108.2192	36.8104	27	38	48	8	5	48	47	10
156	Southwest	SanJuan	PicturedCliffs	-107.4139	36.7311	38	23	26	47	27	17	30	44
157	Southwest	SanJuan	PointLookout	-107.6287	36.5892	51	44	43	56	43	39	51	44
158	Southwest	SanJuan	Rico	-108.2824	36.8641	24	49	35	3	2	41	44	12
159	Southwest	Sierra Grande	Sangre De Cristo	-103.0843	36.3940	16	6	3	7	25	2	2	8
160	Southwest	Plateau/Coconino	Navajo	-111.6160	37.4235	8	7	8	7	7	11	15	9
161	Southwest	Plateau/Coconino	Coconino	-111.9939	37.2538	10	26	61	0	0	38	44	12
162	Southwest	Pedregosa	El Paso	-108.6051	31.7933	10	6	6	19	14	6	6	24
163	Southwest	Pedregosa	Percha	-108.3714	31.5995	4	3	2	1	4	3	1	2
164	Southwest	Pedregosa	Montoya	-108.4646	31.6016	5	4	4	7	6	3	3	8
165	Southwest	Pedregosa	Martin	-109.7933	31.5952	0	1	4	4	1	0	6	4
166	Southwest	Palo Duro	Strawn	-103.8788	34.6606	17	36	6	30	30	37	12	44
167	Southwest	Palo Duro	Clear Fork	-103.9566	34.4600	41	32	15	12	18	29	39	0
168	Southwest	Palo Duro	Cisco	-103.8888	34.7913	9	30	13	30	36	0	4	21
169	Southwest	Palo Duro	Canyon	-103.8713	34.6413	11	36	17	20	23	36	14	9
170	Southwest	Orogrande	Yeso	-107.0381	33.0811	1	11	17	13	13	11	11	17
171	Southwest	Orogrande	Montoya	-106.1454	32.8064	33	30	44	57	12	0	70	43
172	Southwest	Orogrande	Fusselman	-105.9581	32.5517	52	23	55	42	36	2	67	26
173	Southwest	Orogrande	El Paso	-106.3240	32.6820	42	44	54	64	35	40	52	62
174	Southwest	Orogrande	Bliss	-106.3478	32.6988	42	45	60	62	41	45	52	67
175	Southwest	Orogrande	Abo2	-104.9660	32.4749	5	6	5	5	4	7	4	5
176	Southwest	Orogrande	Abo1	-105.7219	33.3256	42	9	11	48	33	20	19	30
177	Southwest	Green River	Pierre	-107.8851	41.1168	12	24	17	12	11	12	18	10
178	Southwest	Green River	Green River	-107.7777	40.8040	33	35	24	37	36	27	29	33
179	Southwest	North Park	Dakota	-106.2698	40.5125	27	17	17	35	24	19	16	30
180	Southwest	SanJuan	PinkertonTrail	-108.1169	36.9413	20	26	35	40	0	29	52	20
181	Southwest	Paradox	Carmel4	-109.1723	39.3410	6	7	8	11	4	4	11	7
182	Southwest	Green River	Dakota	-108.4801	41.5094	60	74	147	124	91	54	90	143
183	Southwest	Green River	Carlile	-108.0896	41.5396	58	65	115	106	91	45	64	95
184	Southwest	Estancia	Yeso	-105.9732	35.3364	12	9	7	13	11	8	7	13
185	Southwest	Estancia	Todilto	-106.4369	35.2897	8	15	21	5	6	14	16	8
186	Southwest	Estancia	Morrison	-106.4059	35.3092	9	15	21	4	3	12	14	8
187	Southwest	Estancia	Mancos	-106.5316	35.2943	7	19	9	5	7	19	11	6
188	Southwest	Estancia	Entrada	-106.4095	35.2906	7	21	17	8	8	13	12	7
189	Southwest	Estancia	Dakota	-106.4625	35.2937	10	18	24	3	6	24	18	10
190	Southwest	Estancia	Chinle	-106.3985	35.2729	11	27	22	12	9	19	18	9
191	Southwest	Paradox	Cutler2	-110.0932	38.6952	18	24	28	0	5	23	8	13

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
192	Southwest	Paradox	Carmel3	-110.9827	39.2896	11	15	9	5	9	19	10	7
193	Southwest	Paradox	Carmel2	-109.9555	39.1223	17	0	24	20	14	10	18	31
194	Southwest	Green River	Entrada	-108.4795	41.1099	76	12	74	84	63	63	80	76
195	Southwest	Paradox	Carmel1	-112.0212	37.8909	17	36	27	13	17	31	25	7
196	Southwest	Paradox	Entrada	-109.6699	39.2119	8	20	20	15	14	23	35	6
197	Southwest	Paradox	Kayenta3	-110.9528	39.2191	15	23	6	12	13	20	11	9
198	Southwest	Paradox	Cutler1	-109.1192	37.5277	40	47	20	44	35	44	29	21
199	Southwest	Paradox	Moenkopi	-109.3120	37.5515	31	24	12	26	37	19	25	16
200	Southwest	Paradox	Mancos	-109.5322	39.3174	10	14	10	5	6	20	9	9
201	Southwest	Paradox	Navajo2	-112.0128	37.7925	23	13	19	28	8	26	19	21
202	Southwest	Paradox	Kayenta1	-109.9508	39.1288	6	3	23	21	18	11	24	30
203	Southwest	Paradox	Kayenta2	-111.7507	37.9020	17	24	6	23	21	16	19	17
204	Southwest	Paradox	Kayenta4	-110.9026	38.0438	20	7	3	5	16	5	3	8
205	Southwest	Paradox	Dakota	-109.6940	39.2498	2	21	32	14	19	26	33	2
206	Southwest	Paradox	Morrison	-109.7465	39.2376	3	23	39	19	19	22	36	3
207	Southwest	Paradox	Navajo3	-110.9586	39.2524	14	21	7	9	12	20	11	8
208	Southwest	Paradox	Navajo1	-109.7349	39.1495	8	11	29	22	16	21	34	1
209	Southwest	Paradox	Navajo4	-108.4741	37.1153	4	11	12	3	4	11	12	3
210	Southwest	Piceance	Wasatch1	-108.1311	39.7752	15	10	29	16	24	15	16	27
211	Southwest	Piceance	Wasatch2	-107.7702	39.3785	8	7	1	7	6	8	3	5
212	Southwest	Piceance	Weber	-108.2301	39.8614	22	32	19	46	0	3	43	22
213	Southwest	Piceance	Rollins	-108.0040	39.4392	6	11	23	16	20	16	24	40
214	Southwest	Fort Worth Palo Duro	N/A	-98.7712	33.2708	47	55	112	99	35	33	70	146
215	Southwest	Kansas Arbuckle Miss	N/A	-99.3620	38.3884	112	136	185	124	96	164	147	157
216	Southwest	Paradox	Summerville1	-109.7706	39.1958	6	22	33	20	19	23	28	8
217	Southwest	Piceance	Mancos	-108.1393	39.5473	47	15	38	53	34	25	49	47
218	Southwest	Piceance	Maroon	-108.2542	39.8095	0	33	30	66	3	13	41	32
219	Southwest	Piceance	Mesaverde	-108.0563	39.6179	31	12	28	46	40	16	24	44
220	Southwest	Piceance	Minturn	-107.7099	39.7947	26	31	0	15	28	9	6	11
221	Southwest	Piceance	Moenkopi	-108.3307	40.0359	14	10	69	14	14	27	36	12
222	Southwest	Piceance	Morrison	-108.1312	39.5401	45	66	58	63	48	33	50	66
223	Southwest	Piceance	Mowry	-108.3448	39.8121	29	38	26	36	39	18	37	40
224	Southwest	Piceance	Parkcity	-108.7647	40.0854	1	1	7	1	1	1	4	1
225	Southwest	Piceance	Shinarump	-108.3107	39.9949	12	12	67	21	2	32	38	14
226	Southwest	Piceance	Statebridge	-108.9428	39.9366	6	14	0	0	9	9	3	3
227	Southwest	Paradox	Summerville2	-111.0146	39.2755	13	18	12	3	6	20	10	9
228	Southwest	Piceance	Belden	-107.7896	40.1090	5	6	9	5	6	5	6	8
229	Southwest	Piceance	Corcoran	-108.0443	39.4892	40	15	35	39	34	22	35	46
230	Southwest	Piceance	Cozzette	-108.0453	39.4484	29	7	35	21	20	17	28	38
231	Southwest	South Park	Dakota	-105.7739	39.0713	2	1	3	11	4	3	5	12

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
232	Southwest	Piceance	Dakota	-108.1090	39.5334	46	62	60	81	48	33	51	67
233	Southwest	Piceance	Entrada	-108.3540	39.6743	38	54	27	62	36	39	36	51
234	Southwest	Piceance	Fortunion	-108.2370	39.7502	12	23	10	27	17	11	13	19
235	Southwest	Piceance	Greenriver	-108.6917	40.0729	0	0	17	3	1	0	18	0
236	Southwest	Piceance	Leadville	-108.2911	39.8891	0	29	16	9	9	14	39	0
237	Southwest	Oklahoma Basins	N/A	-98.3170	35.8658	79	114	220	147	85	79	218	114
238	Southwest	Paradox	Ouray	-109.4912	37.9331	74	43	72	68	65	63	74	97
239	PCOR	Williston Basin	Broom Creek	-101.5151	47.2023	52	43	46	50	48	50	42	54
240	PCOR	Williston Basin	Lower Cretaceous4	-106.9885	45.4701	33	26	9	19	35	28	10	23
241	PCOR	Williston Basin	Lower Cretaceous	-104.0135	46.3241	190	10	169	186	72	165	138	142
242	PCOR	Williston Basin	Lower Cretaceous5	-105.1254	44.3845	22	27	17	11	16	30	9	12
243	PCOR	Williston Basin	Lower Cretaceous3	-104.5874	43.5820	35	34	12	24	34	28	20	21
244	PCOR	Williston Basin	Lower Cretaceous6	-102.6339	48.6855	10	13	14	3	9	10	17	6
245	PCOR	Williston Basin	Lower Cretaceous2	-101.6216	47.2367	24	28	26	29	25	17	31	21
246	PCOR	Denver	Lower CretaceousD	-102.6933	41.1396	77	74	84	79	91	71	73	104
247	PCOR	Denver	Lower CretaceousD2	-101.2202	42.6773	10	7	18	10	9	2	13	12
248	PCOR	Denver	Lower CretaceousD3	-101.2092	42.3886	5	7	5	9	7	1	7	9
249	PCOR	Williston Basin	Madison	-103.6535	46.7464	149	202	200	201	138	221	193	193
250	WESTCARB	Snake River	N/A	-117.3296	43.7376	43	37	16	31	58	17	25	33
251	WESTCARB	Swauk	N/A	-120.9285	47.3499	4	5	26	16	13	13	15	29
252	WESTCARB	Methow	N/A	-120.4904	48.6386	21	11	11	37	16	6	15	33
253	WESTCARB	Hornbrook	N/A	-122.8442	42.3658	11	5	3	24	8	8	6	15
254	WESTCARB	Harney	N/A	-119.1028	43.2181	31	40	47	30	36	38	41	31
255	WESTCARB	Coos	N/A	-124.2894	42.6342	28	15	11	16	35	13	6	21
256	WESTCARB	Chiwaukum	N/A	-120.5387	47.5741	11	6	6	22	13	9	7	24
257	WESTCARB	Cuyama Basin	N/A	-119.7218	35.0316	11	6	11	31	10	10	18	31
258	WESTCARB	Sonoma Basin	N/A	-122.6974	38.3747	7	3	3	22	7	5	6	27
259	WESTCARB	La Honda Basin	N/A	-122.1992	37.2577	7	4	7	16	7	11	10	23
260	WESTCARB	Salinas Basin	N/A	-120.9685	36.0675	14	14	19	62	20	16	17	82
261	WESTCARB	Eel River Basin	N/A	-124.1219	40.5446	6	4	6	12	4	4	13	14
262	WESTCARB	Los Angeles Basin	N/A	-117.9734	33.8554	20	20	28	41	16	11	26	25
263	WESTCARB	Ventura Basin	N/A	-119.0328	34.3685	13	21	37	15	20	19	83	16
264	WESTCARB	Orinda Basin	N/A	-122.0888	37.7839	11	5	6	29	6	0	5	24
265	WESTCARB	Livermore Basin	N/A	-121.8451	37.7322	6	5	9	14	15	6	6	18
266	WESTCARB	Honey Lake Valley	N/A	-120.2834	40.2595	10	8	15	14	9	8	12	15
267	WESTCARB	California Valley	N/A	-116.0013	35.8584	7	5	5	2	4	6	3	4
268	WESTCARB	Chicago Valley	N/A	-116.1508	35.9933	7	4	3	5	9	2	3	6
269	WESTCARB	Greenwater Valley	N/A	-116.5240	36.0854	1	0	3	17	6	3	3	17
270	WESTCARB	Alturas Valley	N/A	-120.5113	41.3788	10	11	0	4	13	5	4	6
271	WESTCARB	Death Valley	N/A	-117.0067	36.4587	20	14	14	52	25	0	14	67
272	WESTCARB	Eureka Valley	N/A	-117.7930	37.2136	8	5	3	13	7	6	5	13

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
273	WESTCARB	Indian Wells Valley	N/A	-117.7792	35.7154	25	18	13	13	13	27	6	12
274	WESTCARB	Amargosa Desert	N/A	-116.4337	36.2973	11	0	9	16	11	7	8	22
275	WESTCARB	Goose Lake Valley	N/A	-120.4136	41.8521	10	12	4	4	15	9	4	9
276	WESTCARB	Bristol Valley	N/A	-115.7981	34.4727	12	9	11	24	3	7	7	17
277	WESTCARB	Clipper Valley	N/A	-115.4179	34.8834	7	11	5	4	6	13	5	5
278	WESTCARB	Chuckwalla Valley	N/A	-115.1475	33.6665	4	14	20	16	12	9	32	24
279	WESTCARB	Lanfair Valley	N/A	-115.0597	35.1646	15	0	14	25	7	7	19	14
280	WESTCARB	Ivanpah Valley	N/A	-115.5458	35.1974	28	26	6	8	21	35	2	2
281	WESTCARB	Goldstone Basin	N/A	-116.9464	35.3625	8	13	18	2	8	15	14	9
282	WESTCARB	Fall River Valley	N/A	-121.4202	41.0594	5	4	6	3	4	4	6	6
283	WESTCARB	Big Valley	N/A	-121.0833	41.1517	8	4	9	3	8	7	7	5
284	WESTCARB	Fremont Valley	N/A	-118.0227	35.1766	9	25	9	8	10	22	6	4
285	WESTCARB	Mesquite Valley	N/A	-115.6677	35.7565	0	0	11	10	2	2	9	10
286	WESTCARB	Pahrump Valley	N/A	-115.9684	36.0138	0	0	14	14	4	2	4	21
287	WESTCARB	Owens Valley	N/A	-118.1416	36.7893	8	2	4	32	18	9	7	22
288	WESTCARB	Saline Valley	N/A	-117.7801	36.7502	5	4	6	19	7	6	6	15
289	WESTCARB	Searles Valley	N/A	-117.3566	35.6674	19	9	8	8	9	19	2	4
290	WESTCARB	Surprise Valley	N/A	-120.0981	41.5409	28	5	5	10	21	8	5	11
291	WESTCARB	Unnamed 12	N/A	-116.2390	35.9276	5	3	3	8	4	4	3	7
292	WESTCARB	Unnamed 5	N/A	-116.1595	34.2989	6	4	3	17	9	4	4	23
293	WESTCARB	Unnamed 6	N/A	-116.3443	34.2817	9	6	6	8	7	9	6	0
294	WESTCARB	Salton Trough	N/A	-115.6778	33.1157	23	21	43	61	36	36	41	81
295	WESTCARB	Santa Maria Basin	N/A	-120.3437	34.8897	23	12	20	37	19	20	19	42
296	WESTCARB	Ward Valley	N/A	-115.0089	34.4054	40	7	7	3	30	18	6	5
297	WESTCARB	Unnamed 3	N/A	-115.1128	34.9168	9	4	2	3	9	4	2	3
298	WESTCARB	Palen Valley	N/A	-115.2003	33.9016	8	5	6	7	9	6	6	9
299	WESTCARB	Pinto Basin	N/A	-115.6446	33.9401	5	7	14	2	3	9	18	3
300	WESTCARB	Unnamed 2	N/A	-115.1990	33.3814	5	5	19	18	10	7	6	14
301	WESTCARB	Unnamed 19	N/A	-116.2684	34.6651	6	6	2	11	5	5	4	11
302	WESTCARB	Palo Verde Valley	N/A	-114.7036	33.6324	14	9	11	11	20	16	3	24
303	WESTCARB	Unnamed 13	N/A	-115.8921	35.0535	6	2	2	5	4	3	2	6
304	WESTCARB	Shadow Valley	N/A	-115.6942	35.4608	15	4	6	12	15	4	5	8
305	WESTCARB	Unnamed 9	N/A	-116.0030	35.2838	4	5	6	9	3	3	5	9
306	WESTCARB	Pilot Knob Valley	N/A	-117.0635	35.5407	1	5	26	0	0	10	14	1
307	WESTCARB	Unnamed 10	N/A	-116.0555	35.1168	8	3	3	6	7	5	3	4
308	WESTCARB	Central Valley	N/A	-120.7163	37.5265	27	18	20	204	77	37	46	191
309	WESTCARB	Tyee Umpqua Basin	N/A	-123.6893	43.7545	77	38	41	36	62	61	26	28
310	WESTCARB	West Olympic Basin	N/A	-124.4128	47.7579	19	14	10	19	26	10	7	23
311	WESTCARB	Whatcom	N/A	-122.5257	48.8799	0	13	11	12	8	12	12	13
312	WESTCARB	Willamette Trough	N/A	-123.0267	44.9321	48	50	6	13	73	27	16	30
313	WESTCARB		N/A	-111.0024	36.1495	59	67	77	109	84	43	162	70

FID	PARTNER-SHIP	BASIN NAME	FORMATION	Centroid		Distance From Centroid to Edge of Formation in Given Direction [miles]							
314	WESTCARB	Coos Bay Basin	N/A	-124.5931	43.7597	22	32	4	16	29	19	11	15
315	WESTCARB	Newport Basin	N/A	-124.2690	44.7945	19	6	6	11	11	6	7	16
316	WESTCARB	Heceta Basin	N/A	-125.1363	44.9605	53	16	15	27	52	20	13	28
317	WESTCARB	Astoria Basin	N/A	-124.3184	45.4982	24	14	8	12	22	14	10	15
318	WESTCARB	Willipa Basin	N/A	-124.7065	47.0082	37	16	12	24	40	16	12	33
319	WESTCARB	Olympic Basin	N/A	-125.4579	48.1380	10	7	22	31	16	14	23	47
320	WESTCARB	Astoria-Nehalem	N/A	-123.3781	45.9021	17	22	26	26	15	9	30	23
321	WESTCARB	Ochoco	N/A	-120.1659	44.0659	70	69	43	39	68	86	30	50
322	WESTCARB	Puget Sound	N/A	-122.4828	47.0804	89	56	33	44	103	74	26	41
323	WESTCARB	Tofino Fuca	N/A	-124.0069	48.1718	0	0	36	7	5	8	21	5
324	WESTCARB	Willapa Hills	N/A	-123.7394	46.8520	30	34	25	43	40	33	19	40

Appendix B: Derivation of cost equations for amine and Selexol scrubbing technologies.

Amine technologies

The NETL (2007b) report describes costs associated with capture of 30%, 50%, 70%, and 90% of CO_2 emissions from the Conesville #5 pulverized coal unit in Ohio using advanced amine based capture technology. Values reported in Table ES-1 of NETL (2007b) include capital costs and fixed and variable operations and maintenance (O&M) costs associated with different amounts of carbon capture, and are shown in Table B-1. Cost data were compared to the amount of carbon captured and regressions were created for the capital, fixed O&M, and variable O&M costs.

Table B-1. Capital, fixed operations and maintenance (O&M), and variable O&M costs reported in NETL 2007b for different levels of CO_2 capture by amine scrubbing from the Conesville (Ohio) #5 pulverized coal unit.
Note: Values in black are from Table ES-1 of that report. Values in blue (CO_2 Captured [tonne/hr]) are just a unit conversion using 2,240 lb per tonne.

Report scenario	CO_2 Captured [lb/hr]	CO_2 Captured [tonne/hr]	Capital Cost [2006 $1000]	Fixed O&M [2006 $1000/yr]	Variable O&M [2006 $1000/yr] (not including makeup power)
90% Capture	779,775	**348**	400,094	2,494	17,645
70% Capture	607,048	**271**	365,070	2,284	14,711
50% Capture	433,606	**194**	280,655	2,079	10,876
30% Capture	260,164	**116**	211,835	1,869	7,019

A salient paragraph that addresses these costs:

> The project capital cost estimates (July, 2006 cost date) include all required retrofit equipment such as the amine-based CO_2 scrubbing systems, the modified flue gas desulfurization (FGD) system, the CO_2 compression and liquefaction systems, and steam cycle modifications. ... The variable O&M (VOM) costs for the new equipment included such categories as chemicals and desiccants, waste handling, maintenance material and labor, and contracted services. A make-up power cost (MUPC) for the reduction in net power production is also included in the VOM costs[v]. … The fixed O&M (FOM) costs for the new equipment include operating labor only.
>
> - NETL, 2007b, p. ES-4.

Values in Table B-1 do not include the make-up power because it is handled separately in WECS II. Values from Table B-1 are plotted in Figure B-1 and B-2, and the resulting best fit lines are the relationship between amount of CO_2 capture and associated costs used by the WECS II model. These relationships are summarized in Table B-2.

[v] The make-up power costs used in the NETL 2007b study are listed separately in Table ES-1 of that report, and the variable O&M costs in Table B-1 do not include the make-up power component.

Table B-2. Equations relating capital costs, variable operations and maintenance (O&M) costs, and fixed O&M costs to the amount of carbon captures using amine technologies.
Note: The goodness of fit (R^2) parameter refers only to the fit of the equation to 4 estimated points from one report (NETL 2007b) on one pulverized coal unit, and not to the overall reliability of these equations.
(Same as the first 4 lines of Table 8-1 in the main report body.)

Cost Type	Equation (all $ are year 2006)	R^2
Amine Capital	CCost[$1000] = 839.59*$CO_2$Captured[tonne/hr] + 119453	0.98
Amine VO&M	VO&M[$1000/yr] = 46.183*$CO_2$Captured[tonne/hr] + 1838.6	1
Amine FO&M	FO&M[$1000/yr] = 2.6896*$CO_2$Captured[tonne/hr] + 1556.9	1

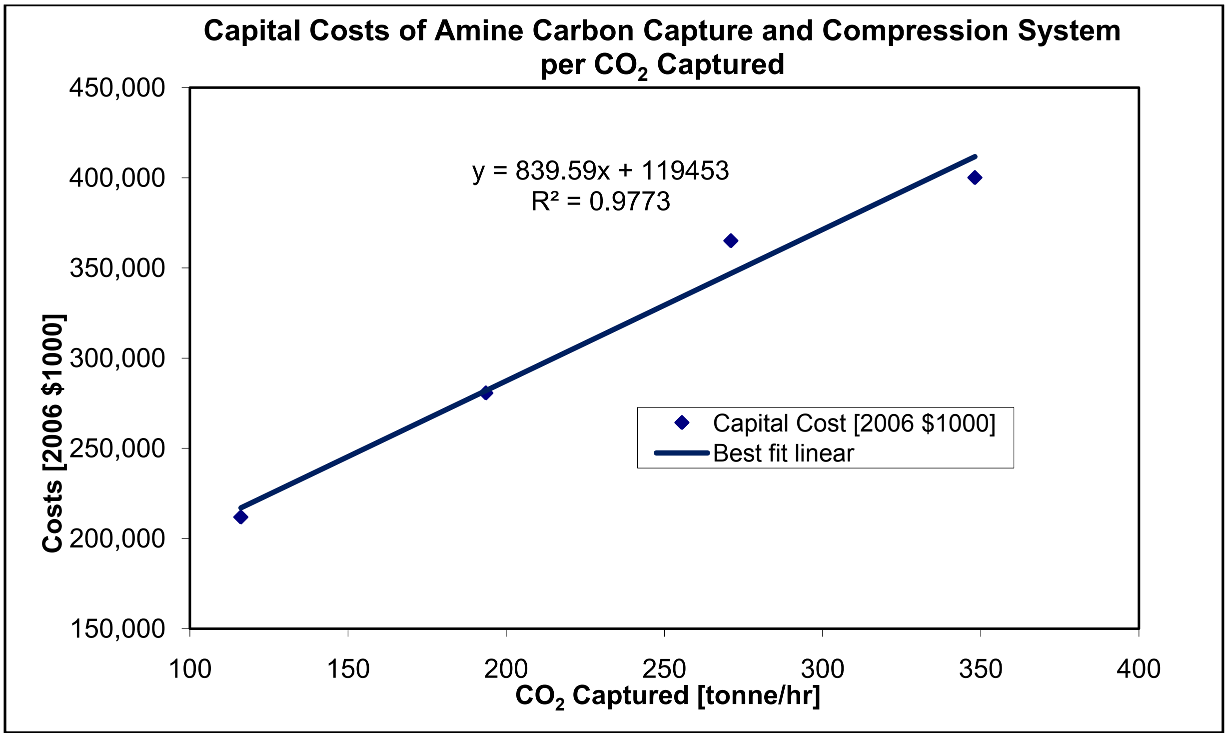


Figure B-1. Regression relationship between capital costs and amount of CO_2 capture.
Note: Values from NETL 2007b and illustrated in Table B-1.

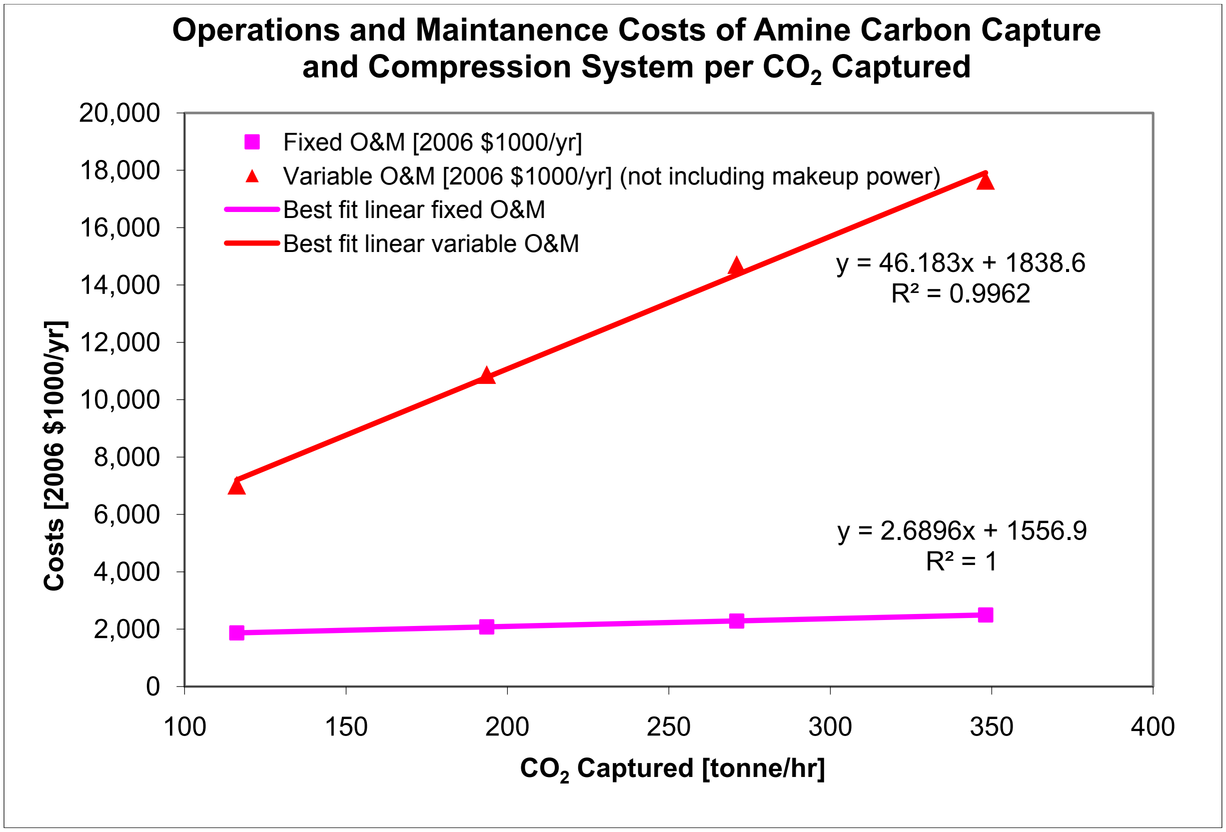


Figure B-2. Regression relationship between operations and maintenance costs and amount of carbon capture.
Note: Values from NETL 2007b and illustrated in Table B-1.

Selexol technologies

Estimates for Selexol based processes were derived from the NETL report (2007a) number 2007/1281 entitled "Cost and Performance Baseline for Fossil Energy Power Plants study, Volume 1: Bituminous Coal and Natural Gas to Electricity" which includes costs and performance information for IGCC plants with and without Selexol based carbon capture technology. The difference in cost with and without carbon capture was divided by the difference in emissions with and without carbon capture to get an estimate of the added costs associated with Selexol based carbon capture. This approach is based on costs of new IGCC plants, and may underestimate costs for carbon capture in a retrofit situation. Table B-3 shows the manipulation of data from the NETL (2007a) report to derive estimates for the costs of adding Selexol based carbon capture to an IGCC plant. The four values in the highlighted cells in the bottom right are used in the WECS II model, and can be seen in the appropriate formulas in Table 8 in the main body of this report.

Table B-3. Capital and operations and maintenance (O&M) costs associated with adding Selexol carbon capture and compression to IGCC power plants.
Note: The values in black are from NETL (2007a), and values in blue are calculated according to the formulas shown. The far right column is an average of the 3 columns to the left of the far right column. The four values in the highlighted cells in the bottom right are used in the WECS II model, and can be seen in the appropriate formulas in Table 8-1 in the main body of this report.

		Row ID	NETL 2007a Exhibit Number or Formula	Selexol Vendor			
				GEE	ConocoPhillips	SHELL	Average
IGCC no CCC	Capital Costs $[10^{6}\ \$]$	A	3-29, 3-62, & 3-95	1160.9	1080.2	1256.8	1166
	Fixed O&M $[10^{6}\ \$/yr]$	B	3-31, 3-64, & 3-97	22.6	22.0	22.4	22
	Variable O&M $[10^{6}\ \$/yr]$	C	3-31, 3-64, & 3-98	29.1	27.7	28.2	28
	Fuel Use [tons/day]	D	3-31, 3-64, & 3-99	5876	5566	5433	5625
	CO_2 Emissions [lb/hr]	E	ES-2	1123781	1078144	1054221	1085382
IGCC no CCC	Capital Costs $[10^{6}\ \$]$	F	3-45, 3-78, & 3-111	1328.2	1259.9	1379.5	1323
	Fixed O&M $[10^{6}\ \$/yr]$	G	3-47, 3-80, & 3-113	24.3	24.0	22.6	24
	Variable O&M $[10^{6}\ \$/yr]$	H	3-47, 3-80, & 3-114	31.5	30.9	29.1	31
	Fuel Use [tons/day]	I	3-47, 3-80, & 3-115	6005	5734	5678	5806
	CO_2 Emissions [lb/hr]	J	ES-2	114476	131328	103041	116282
Cost of CCC	Capital Costs [$1000/(tonne/hr)]	K	2240*1000*(F-A)/(E-J)	$371.27	$425.18	$288.99	**$ 361.8**
	Fix O&M [($1000/yr)/(tonne/hr)]	L	2240*1000*(G-B)/(E-J)	$ 3.81	$ 4.80	$ 0.59	**$ 3.1**
	Var O&M [($1000/yr)/(tonne/hr)]	M	2240*1000*(H-C)/(E-J)	$ 5.25	$ 7.66	$ 2.19	**$ 5.0**
	Fuel Use [(tons/yr)/(tonnes/hr)]	N	2240*365*(I-D)/(E-J)	104	145	211	**153**