National Energy Technology Laboratory

OFFICE OF FOSSIL ENERGY

FE/NETL CO_2 Saline Storage Cost Model: User's Manual

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List of Exhibits

Acronyms and Abbreviations

AoR	Area of review
ARI	Advanced Resources International, Inc.
CAPEX	Capital Expenditure
CO_2	Carbon dioxide
CTS	capture, transport, and storage
CTUS	capture, transport, utilization, and storage
DOE	Department of Energy
DST	Drillstem test
EPA	Environmental Protection Agency
ERR	Emergency and remedial response
ESPA	Energy Sector Planning and Analysis
FE/NETL	Fossil energy/National Energy Technology Laboratory
FR	Financial Responsibility
ft	Foot, Feet
G&A	General and administrative
IEA GHG	International Energy Agency Greenhouse Gas R&D Programme
IOU	Investor-owned utility
IRR	Internal rate of return
LIBOR	London Interbank Offered Rate
LIDAR	Light detection and ranging
mi	mile
MPa	Megapascal
MVA	Monitoring, verification, and accounting
N/A, NA	Not applicable
NETL	National Energy Technology Laboratory
NPV	Net present value
O&M	Operation and maintenance
OPEX	Operating Expenditure
PAA	Purchase/acquire/analysis
PISC	Post-injection site care
psig	Pound per square inch gage
PSFM	Power systems financial model
R&D	Research and development
tonne	Metric ton (1,000 kg)
UIC	Underground Injection Control
USDW	Underground source of drinking water
VSP	Vertical seismic profile

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Introduction

The purpose of this manual is to assist the modeler in understanding the functions of the Fossil Energy/National Energy Technology Laboratory (FE/NETL) Carbon Dioxide (CO_2) Saline Storage Cost Model. This manual will outline the major outputs, provide a general understanding of how the outputs are calculated, and provide a more detailed understanding of how a modeler can edit the inputs to affect outputs for the purpose of evaluating a storage project.

The FE/NETL CO_2 Saline Storage Cost Model is an Excel-based model that consists of four modules (Exhibit 1): Project Management, Geologic, Activity Cost, and Financial. In this workbook, the function of each module is distributed across one or more worksheets (tabs).

Project Management Module: Site for project inputs that define the overall scope of the storage project and modeled outputs. Modeler can conduct multiple storage cost analysis from this module, modifying key inputs without entering the other modules.

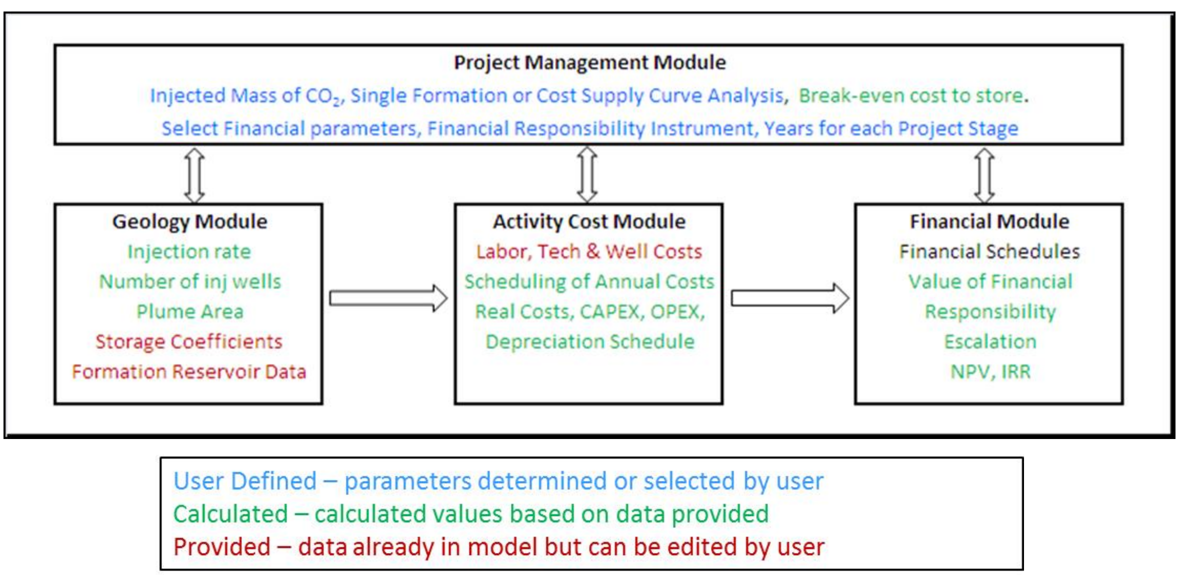
Geologic Module: Site for geo-engineering equations, storage coefficients, geologic database; calculates injectivity and plume area for CO_2. This module will also calculate water withdrawal from CO_2 storage reservoir as well as subsequent treatment and disposal of water not rendered potable.

Activity Cost Module: Site for cost database for all technology and labor used in a project; generates annual costs per technology/labor applied over life of storage project.

Financial Module: Site that generates project financial statements and provides the project management sheet with the ability to solve for key outputs discussed in Section 1.1. Calculation of financial responsibility cost and cost of instruments to satisfy financial responsibility requirements are done within this module.

There is also a 'READ ME FIRST' tab that provides useful information with respect to color and font conventions along with fundamental model assumptions that a user is not able to edit.

Exhibit 1 FE/NETL CO_2 saline storage cost model structure



The design of the FE/NETL CO_2 Saline Storage Cost Model incorporates the regulatory requirements of the UIC Class VI regulations. The model estimates costs for a CO_2 storage project in a saline reservoir. These costs occur in one or more of the five stages of a storage project (Exhibit 2): regional geologic evaluation, site characterization, permitting, operations, post-injection site care (PISC), and site closure. Long-term stewardship is outside the scope of Class VI regulations and is not included in the model; however, a provision for collection of money for a long-term stewardship trust fund is provided. This provision should not be confused with the trust fund option for financial responsibility. The purpose of this model is to mimic CO_2 storage operations in order to estimate the costs associated with a potential CO_2 saline storage project; this is not reservoir modeling software.

Exhibit 2 Project stages for a CO_2 saline storage project

Regional Eval.	Site Selection & Char.	Permitting & Inj. Well Drilling	Operations	Post-Injection Monitoring	Long-Term Stewardship
	UIC Class VI Regulations				Developing State Regulations
			Class VI Permit		
0.5 to 1 year	3+ years	2+ years	30 to 50 years	10 to 50+ years	rest of civilization
gather existing data, develop several prospects	select a site, acquire new data (drill wells, shoot seismic), prepare permitting plans	permit awarded to drill injection wells, final approval to begin injection.	inject CO_2, drill monitoring wells & remediate existing wells as needed, MVA	monitor site, establish non-endangerment, close and restore site	another entity (e.g., a state) takes over
assemble acreage block (surface access/pore space; $/acre signing bonus)		Secure financial responsibility upon permit application; as required, pay into trust fund for Long-term stewardship			
	25% success rate assumed		pay $/tonne/acre royalty fees		
negative cash flow			positive cash flow	negative cash flow	covered by fee paid during ops

1 Key Outputs

The key outputs of the Saline Storage model are selected by clicking on one of two macro buttons, shown in Exhibit 3 posted in the 'Project_Management' tab between Columns M and T:

1. **Cost analysis of a single formation:**

   1A Find CO_2 Price that Makes NPV Zero: A break-even net present value (NPV) analysis that solves for the price that an individual project in a specific formation must charge in its first year in order to return an effective NPV of zero. The NPV will not be zero, but it will be the smallest positive number that can be obtained in solving for a break-even CO_2 price to the second significant digit. For example, if the break-even analysis is run and the CO_2 price is $20.02 with an NPV of $95,000; the project would return a negative NPV if the modeler charged $20.01. Therefore, it would be safe to call $20.02 the NPV zero price since the positive NPV is no more than a rounding issue.

   1B Find NPV at A Particular Cost to Store: If the modeler wants to know the NPV of a project for a price different from the break-even value, then the modeler should enter that price value in the orange colored cell (P15) for the Base Year. The resulting NPV and internal rate of return (IRR) will be posted in the blue cells below the orange 'First Year Price of CO_2' cell.

2. **Cost Analysis of Multiple Formations:** An output where the analysis in number one is replicated for each reservoir formation posted in the geologic database and read by the model for analysis. This output is posted to the 'ResSum1' tab. This newly generated sheet will show the break-even analysis, which results from the 'Find CO_2 Price that Makes NPV Zero' button, for each formation as well as the total amount of CO_2 stored in the formation and other descriptive detail about the formation for a modeler to review. Data posted at the tab can be plotted to illustrate a CO_2 potential storage cost supply curve.

Exhibit 3 Key outputs macros

Macros

Find CO2 Price that Makes NPV Zero

Control for type of injection project	0	Set to 1 for injecting CO2 to fill max. possible plume area
		Any other number indicates inject specified mass of CO2

	Base year	Proj start	Inj start	
Year	2008	2011	2017	
First Year Price of CO2	7.47	8.16	9.75	$/tonne
Net Present Value (NPV) of project		93,757		2011$
Internal rate of return (IRR) for project		12.0%		

Run Title:	Baseline Case

Evaluate Formations

First formation number:	1
Last formation number:	226
Formation just processed:	

Control for formation structure	0	Set to 1 for General structure
		Set to 2 for dome, anticline, 2 inclines and flat
		Set to 3 for dome, anticline and flat
		Other number for dome, anticline and regional dip
Name of workbook to store ResSumn sheet	xNewResultsFile1.xlsm	

IMPORTANT NOTE: The modeler must enable macros in Excel for the model to function.

2 Model Conventions and Architecture

Model conventions are the consistent use of specific colors, as seen in Exhibit 4, throughout all modules to provide immediate visual indicators of the purpose of certain cells. The most important convention, the orange input cell color, is listed first.

The user can change values in any orange cell. In order to change a value, after opening the model, the user must first enable macros.

Exhibit 4 Model color conventions

Conventions for text and cell color/style	
Cell Color Conventions	
Inputs specified in this cell (Type in this cell)	
Intermediate value cells within an input table that are NOT input cells	
Intermediate values (Different colors used to distinguish rows, columns, or sections)	
Title or heading rows	
Overview or Instruction sections	
Cells directly referencing other modules (3 Modules = Activity, Geology, Financial)	
Schedules referenced in the back-end cost items sheet	
Geology module key outputs used in other sheets	
Geology module: other critical outputs or intermediate calculations	
Geological parameters from geology database	
Font Conventions	
Used only for back-end cost items binary switch:	hard-value, reference switch
Base font:	Calibri 10
Hyperlinks to places within the document:	Hyperlink Text

Model Architecture

As previously mentioned, the model has four fundamental modules, all of which incorporate an element of modeler input as well as intermediate outputs that build up the key outputs discussed below.

2.1 Project Management Module

Key management decisions are entered in this module including annual volume of CO_2 injected, years of injection, time span for other stages of a storage project, some 2-D and 3-D seismic parameters, well spacing for monitoring wells, selection of financial responsibility instrument(s), and financial parameters defining the business scenario to be modeled.

If a single formation is being modeled, that formation is selected in this module.

A considerable amount of output information is posted in this module, which facilitates a ready comparison of different model parameters applied to a single formation. The modeler can stay in this module while performing numerous model-runs on a single formation.

The output is presented in two worksheets, 'ResSum' and 'ResSum1.' 'ResSum' is the worksheet containing formulas to calculate or reference the values for model output. This worksheet is hidden in the model, so the tab needs to be unhidden to view. In order for the 'ResSum' formulas to not change with each change in formula and structure, their output values are pasted in the 'ResSum1.' The user makes no changes to either of these worksheets. Any parameter changed in the Project Management Module is not reflected in 'ResSum1' until the macro is run, which updates all of the tables.

The macro also saves this output in a separate Excel workbook titled 'xNewResultsFile1.xlsm'. The user should make sure that this workbook is saved in the same folder as the model, with the name that is posted on the Project Management sheet in cell Q34. When the macro is run, a new sheet will be inserted by the model into this workbook

2.2 Geologic Module

This module contains the geologic database and geo-engineering equations that calculate injectivity and plume area, the two fundamental cost drivers for any CO_2 storage project. The ability to model water withdrawals (production) from the storage reservoir, surface handling or treatment and injection (disposal) is also part of this module.

This module consists of three worksheets: 'Geol Sal,' 'Geol DB Sal,' and 'Water.' Below is a brief description of the function of each of the worksheets in the Geologic Module.

Geol Sal Worksheet

1 - Overview

Section 1 provides an overview of the full worksheet, an explanation of structure, references for methodologies employed, and cell color convention.

This worksheet:

- Specifies geologic properties of the injection formation,

- Determines a CO_2 storage coefficient for a specified fraction of the injection formation, calculates the area of the CO_2 plume for this storage coefficient, and calculates the total mass of CO_2 that can be stored in the fraction of the injection formation where this storage coefficient is applicable, and

- Calculates the number of injection wells needed to inject the maximum daily mass of CO_2 to be injected.

2 - Outputs

Section 2.1 is a summary of properties for the injection formation selected, such as reservoir properties, temperature, fracture pressure, and latitude and longitude at centroid of surface area.

Section 2.2 presents the results of CO_2 to be stored, including years of injection of CO_2, rate of injection of CO_2, and total mass of CO_2 injected.

Section 2.3 shows information pertaining to the CO_2 plume area and the mass of CO_2 that can be stored such as the density of CO_2, the type of structure used, and the diameter of the CO_2 plume area.

Section 2.4 shows the rate of injection of CO_2 in each injection well and the number of injection wells for the selected methods of Law and Bachu, Advanced Resources International, Inc. (ARI), and Cinar et al. The model has not been tested with either the ARI or Cinar et al method for calculating the rate of injection.

3 - Inputs

The modeler specifies inputs related to geologic properties and CO_2 storage coefficients. The number of wells needed to inject the desired mass rate of CO_2 into the injection formation is calculated within this tab.

Section 3.1 is an overview of the worksheet and provides an explanation on the structure of each section regarding inputs from other worksheets, general inputs related to geology, specifications of geologic parameters for injection formation, inputs related to CO_2 storage coefficients and calculating maximum CO_2 plume area, and inputs related to determining the number of injection wells.

Section 3.2 reproduces inputs specified on other worksheets that are needed to calculate the area of the CO_2 plume and the number of injection wells. Specifically, these inputs all relate to the mass injection rate for CO_2 and the duration of injection. The actual annual mass rate of CO_2 injection can be different from the nominal value. The modeler does not need to input any additional information here.

Section 3.3 provides general inputs related to geology, such as temperature and pressure gradients, and information needed to estimate the fracture pressure.

Section 3.4 allows the modeler to specify the geologic properties and parameters that are used in the rest of 'Geol Sal' and in other sheets.

Section 3.5 allows the modeler to specify the CO_2 storage coefficient and the fraction of the injection formation for which the CO_2 storage coefficient is applicable.

Section 3.6 allows the modeler to specify the method used to calculate the mass rate of CO_2 that can be injected into a single well (either vertical or horizontal). This mass rate is used to calculate the number of wells needed to inject the maximum mass of CO_2 that the project is designed to handle. The inputs needed to perform the calculations for each method are specified in this section. The Law & Bachu method is the default method for calculating the CO_2 injection rate. The ARI and Cinar method have not undergone much testing to date.

4 - Surface Area of CO_2 Plume and Maximum Mass of CO_2 that the Formation Can Theoretically Store

Section 4.1 provides the total mass of CO_2 injected over the duration of the project, basic geologic parameters, density of CO_2 at midpoint of formation, CO_2 storage coefficient, and surface area of CO_2 plume.

Section 4.2 compares the total mass of CO_2 injected to the total mass of CO_2 that the reservoir formation can theoretically store.

Section 4.3 provides the total CO_2 that can be injected in the storage (reservoir) formation in different structural settings: dome, anticline, 10^o incline, 5^o incline, and flat or regional dip. Regional dip is the combination of 10^o incline, 5^o incline, and flat structural settings.

5 - Rate of Injection of CO_2 in each Injection Well and Number of Injection Wells

In this section, the number of injection wells that are needed to inject a maximum daily mass of CO_2 into an injection formation is calculated. Three methods are provided for estimating the number of active and total injection wells. These methods are known by their authors. The first two are Law & Bachu and ARI. The third, Cinar, provides for vertical and horizontal wells either fractured stimulated or not.

Section 5.1 provides the results for the selected method, which includes the number of injection wells and the rate of injection of CO_2 in each well.

Section 5.2 provides a number of input parameters common to more than one of the three methods that are provided.

Section 5.3 uses the method developed by Law and Bachu (CCSTP, 2009) to calculate the number of vertical injection wells needed to inject the desired daily mass of CO_2. No enhancement to permeability from hydraulic fracking is provided in this method.

Section 5.4 uses the method developed by ARI (CCSTP, 2009) to calculate the number of vertical injection wells needed to inject the desired daily mass of CO_2. No enhancement to permeability from hydraulic fracking is provided in this method.

Section 5.5 uses the methods developed by Cinar et al. (2008) to calculate the number of vertical injection wells without/with hydraulic fracking (Sections 5.5.1 and 5.5.2) and the number of horizontal injection wells without/with hydraulic fracking (Sections 5.5.3 and 5.5.4).

Attachment A: Lookup table for site-specific CO_2 storage coefficients based on lithology, depositional environment, and structural setting: dome, anticline, 10^o incline, 5^o incline, flat, and regional dip. The storage coefficient for regional dip is the average of the values for 10^o incline, 5^o incline, and flat. The CO_2 storage coefficients in the Attachment A table were obtained from the International Energy Agency Greenhouse Gas Research and Development Programme (IEA GHG) report (2009). The values in the first 21 rows are from Table 13 while the remaining values are from Appendix E within the IEA GHG report.

Geol DB Sal Worksheet

The geologic database is posted within this worksheet, and the source for each line of data can be found in Column AL. Presently, this database has geographical and geological data for 62 formations partitioned into 226 reservoirs scattered across 32 basins in 26 states. The modeler can edit this data as he or she sees fit or create a new database.

Water Worksheet

The worksheet labeled 'Water' contains inputs and calculations related to the model method for including water production, treatment, and disposal or sale. The calculations on this sheet pull data from other parts of the geology module, use data that has been entered by the user, and use a data set from an outside source. The results of the calculations are then carried through the model via the activity module and cost line items, in the same manner as other costs. The revenue in the financial module is also directly related to the input on the water worksheet. The On/Off switch for the water method and the percentage of water treated control are on the Project Management sheet, but all other water-related items are controlled through the Water sheet.

2.3 Activity Cost Module

The activity module contains the activities that are performed in each stage of a CO_2 storage project. Technology and labor are the key variables comprising activity costs. For instance, high-cost activities include drilling wells and running seismic. Low-cost activities include taking samples, running tests, and writing reports. There are currently 942 different activities in this module that can be applied to the CO_2 storage project that is linked to one of the reservoir formations listed in the geologic database. Information included for each activity includes the unit cost of the activity item, the overall quantity of each activity (number of times performed), and the timing of the activity (the year in which the activity was performed).

The activity module:

- Provides a cost database for all activity costs related to the CO_2 storage project,
- Provides the modeler the opportunity to enter their own cost data, and
- Allows the modeler to change the timing for a particular activity, i.e. the year(s) over which this activity will occur.

A brief description for each of the worksheets making up the Activity Cost Module follows.

Activity Inputs Worksheet

These items are within the 'Activity_Inputs' tab and are divided into four table groups:

1. **Parameters consistent across all activities**

   Tables beginning with 1.1 contain cost items utilized across all activities; labor cost is the key variable within this table.

2. **Activity specific parameters**

   Tables beginning with 2.1 contain project activity-specific cost items, listed below, that are costed in a specific stage of the project life.

   a. Regional evaluation for site selection
   b. Site characterization
   c. Permitting
   d. Operations
   e. There are no unique activities in this cost item group for the Post-Injection Site Care and Site Closure stage.

3. **Parameters used in activities across multiple project stages**

   Tables beginning with 3.1 contain cost items for activities across multiple stages are activities that incur costs that can be applied to all stages in the project's lifespan. The activity types are listed below.

   a. Fees per tonne CO_2 (other expenses)
   b. Fees, one-time (other expenses)

c. Periodic reports
d. Fluid samples
e. Gas samples
f. Aerial/satellite survey
g. Surface seismic: 3-D & 2-D
h. Wellbore seismic: (for in-reservoir and above-seal wells)
i. Electrical
j. Other geophysical
k. Atmospheric
l. Injection well monitoring
m. Data analysis and modeling

4. **Well drilling costs**

Tables beginning with 4.1 contain well drilling cost items for site characterization wells, injection wells, all types of monitoring wells, and water production/injection wells. The following types of costs can be selected and applied to every well type drilled during the project's lifespan:

a. Permits, other than Class VI
b. Drilling costs
c. Wireline (geophysical) logging
d. Core recovery
e. Fluid recovery
f. Well tests
g. Well seismic
h. Analysis
i. Completion
j. Monitor well downhole equipment
k. Operations and maintenance (O&M)
l. Annual mechanical integrity test
m. Plug and abandon

A modeler will use the 'Activity_Inputs' worksheet to change the costs applied by the model. For each orange cell, the modeler inputs a unit cost as labeled in each table. These tables are populated with the best publically available data (EPA 2010 and API 2006), but if the modeler wishes to change a cost for analysis or has better data available, the new data is entered in the orange cells.

Exhibit 5 Table 3.6 Aerial/Satellite Survey; occurrence of costs

3.6 Aerial/Satellite Survey

	Technology Cost			Frequency (yrs) for Application of Technology			
	Mobilization Cost	Cost per mi2	% Inc. for Data Pro.	Site Characterization	Permitting	Operations	PISC and Site Closure
	$	$/mi2	%				
Aerial survey (Land, land use, structures, etc.)	3,100.00	415.00	41.50	1			
Air-magnetic survey for old wells	5,200.00	11,160.00	1,116.00	1			
Synthetic Aperture Radar (SAR & InSAR)	5,200.00	11,160.00	1,116.00				
Color Infrared (CIR) Transparency Films	5,000.00	6,250.00	625.00				
Thermal Hyperspectral Imaging			0.00				
Ecosystem Stress Monitoring			0.00				
% over 3D marg	% of mi2	0%					

User Input Selection		Years that will be used		*
Begin Year	End Year	Begin Year	End Year	
0	0	2	4	Site Ch.
0	0	5	6	Permit.
0	0	7	36	Ops.
0	0	37	86	PISC

The modeler can also use the 'Activity_Inputs' sheet to establish when specific costs are incurred. For example, in Exhibit 5, an Aerial Survey and Air Magnetic Survey are conducted only during site characterization, project years 2 to 4. To utilize these technologies or technologies in other table, values representing frequency of use can also be posted in the other storage project stages: permitting, operations or PISC. A value of 1 means the technology is used and costed annually, a value of 5 and the technology is used and costed every 5th year.

Utilizing the smaller table on the right in Exhibit 5 the modeler has some options on when costs occur. The four rows of this smaller table each represent one of the project stages in the larger table to the left. Because the orange cells in this table are set to zero, the gray cells (Years that will be used) are the default values established in the Project Management module. To apply the default time frame for a particular stage, leave '0' in the begin year and an end year cells. In Exhibit 5 the default time frame is applied to all four project stages and the technology is utilized at the frequency established in the larger table to the left. To override the default time frame, the timing information must be entered in the orange cells (User input selection) for each project stage in which the technology will be applied other than the default time frame. To apply the technology once, in a single year, enter the same project year in the begin year and end year cells. Enter two different project years within the default time frame and the technology will be applied only within that constrained time frame. Another way to turn off a cost here is to enter a number larger than 200, such as '9999,' into the begin year and end year cells under the 'User Input Selection' table.

Within the 'Activity_Inputs' sheet, the modeler may wish to select and deselect which technologies will be used. The selection of various technologies is done differently depending on the table. For all well-drilling cost (Tables 4.x), to the right of each cost column is a column labeled 'ON/OFF'. The modeler should enter an 'x' in this column to turn on the cost or leave the cell blank to turn off the cost.

Surface Equipment Cost Worksheet

This worksheet specifies capital costs and annual O&M costs for surface equipment at a saline storage site. Surface equipment includes a 'feeder' pipeline; equipment, roads and buildings needed to operate the injection wells; and equipment and roads related to storage field operations.

Section 5.0 Capital Costs and Annual Operating and Maintenance (O&M) Costs for Back-End Cost Items Sheet

-- This section provides the capital and O&M costs for various kinds of surface equipment at a saline storage site. These costs are used in the Back-End Cost Item sheet.

Section 5.1 provides capital and O&M costs for a feeder pipeline. The feeder pipeline transports CO_2 from a main CO_2 pipeline to the saline storage site.

Section 5.2 provides the capital and O&M costs for equipment, buildings, and roads needed to operate injection wells. These include the following costs:

-- Costs for a pump that boosts the pressure of CO_2 entering the saline storage facility. At some facilities, the pressure may not need to be boosted. However, the capital and O&M costs are presented here in the event the pressure of the CO_2 needs to be increased before it is injected.

-- Costs for the distribution pipeline network. This network consists of a header or manifold and pipes. The header connects to either the feeder pipeline or the exit of the boost pump and directs the CO_2 flow into smaller diameter pipes. These pipes then transport the CO_2 to the injection wells.

-- Costs for building, control equipment, and access road to building.

Back-End Cost Items Worksheet

This worksheet enables the modeler to fully audit and review the model calculations. It calculates the appropriate annual cost for each activity utilized in a storage project and posts this cost in the year(s) it is incurred. Each activity cost is listed in this worksheet by the stage in which it may be used, thus creating multiple listings for each activity. These costs are listed this way in order to provide an auditable one-line record of each value in the cost calculation. Costs occurring in each year are summed, and this information is picked-up by the Financial Module. A depreciation schedule is calculated in the Financial Module based on information from this worksheet. Presently, certain costs are labeled either 'Capital' or 'Expense;' however, the modeler can change these labels. Capital costs are added to a depreciation schedule where a simple straight-line depreciation calculation is applied.

Although it is not necessary for model output, the modeler may perform his or her own audit to confirm that an activity cost is properly calculated by the model and applied to each year intended by the user. To follow a cost calculation thoroughly, the modeler needs to trace the cost calculation sequence across many columns in this worksheet.

- First, the modeler must identify the cost of interest. This task can be done using Columns A, B, C, and D; which are the Cost ID, Stage, Sub-stage, and Item, respectively.
- Descriptive information about the cost is found in the next twelve columns, E through P. These items are used for summing costs across various criteria.
- Columns Q-AO show the main components of the cost calculation. These columns are structured in a format meant to standardize all cost calculations: ax+by+cz.

- In addition to the main components, there are four factors by which the ax+by+cz value is multiplied. These four factors are in Columns AP-AT. The first factor is a binary switch that turns on or off the cost item. The second factor is used for any costs that include a value by which the entire line calculation is multiplied. This factor is shown in two columns, one for the value and one for the unit. The third factor is the process contingency which is incurred on all costs for monitoring activities. The last factor is the project contingency which is incurred for all capital costs. Column AU calculates all cost components from the left of the worksheet to show the effective cost-per-year before any year-dependent factors.
- Columns AV-AX identify which, if any, year-dependent factors apply to the cost.
- The timing information for the cost; begin year, end year, and periodic value; is shown in Columns AY-BA. The same three values are used to define a cost's timing regardless of whether the cost is an annual cost, a one-time cost, or a periodic cost.
- Total incurred cost values are in the next three Columns, BB-BD. These columns represent the sum of real, nominal, and present-value dollars across the row.
- To see the exact cost posted in each year of the project, in 2008 dollars, the modeler should look at Columns BE-IV. These columns show a 200-year schedule of costs, since 200 years will cover the project time. Rows 3 and 4 show the escalation and discounting for each year. The formulas in the cells from year 1 through year 200 use the begin year, end year, and periodic value to decide whether or not the cost should be posted in a given year. Also, any factors that are year dependent, such as well count or plume area, are multiplied by the other cost components in this worksheet. These year-dependent factors are held in the 'Plume and Well Schedule' worksheet.

Plume and Well Schedule Worksheet

This worksheet lists time-dependent geologic factors, such as well counts and plume growth, in a timeline**.** In this sheet, the modeler can find all year-dependent factors; including plume area, area of review, and well counts. The inputs and assumptions relevant to these values are also posted on this sheet for reference. This worksheet shows how many wells are added in a given year and the plume area in a given year that would need to be covered if a seismic shoot were required by the manager.

Geo-Activity Interaction Worksheet

This worksheet provides information to the modeler on the geology values that are transferred from the Geologic Module to the Activity Cost Module.

Drilling Costs

This worksheet performs the calculation of drilling costs. The first table covers all equations used for drilling cost calculations and the states or regions utilizing those calculations. The next table contains the calculations for all state or regions based on information from the first table. Columns AB through AI show the well depths used, which are determined in the Geology Module. These depths are then incorporated into equations to determine costs, Columns AJ through AQ. These costs are based on 2006 dollars and are given in 1000 dollars per foot. Finally, in Columns BF through BM, the costs are converted to 2008 dollars and are given in dollars per well. For all wells other than groundwater and Vadose Zone wells, the algorithm requires the cost to be multiplied by 1000, which is done in these cells.

2.4 Financial Module

This module creates a financial evaluation of a business scenario for a specific storage project from an NPV perspective using the financial parameters posted in the Project Management Module and the schedule of investments and expenses made in the Activity Cost Module. The key outputs, discussed in Section 1.1, use a break-even analysis calculated in the FinancialModule to provide results.

The Financial Module (FinMod tab) consists of several tables:

Table 1: Financial Inputs –Summarizes key inputs taken from the Project Management Module including capitalization, cost of equity and debt, tax rate, escalation rate, and starting year of the project. The period of time that the modeled project runs certain aspects of its activities are also defined.

Table 2: Escalation and Discounting Factors –Shows the factor that a real sum needs to be modified in order to convert it into nominal dollars and then discount it back to a present value.

Table 3: Outputs from Activity Module –Shows operating expenses, capital expenses, and depreciation and amortization. This table also escalates all of the real dollar sums into nominal dollars in the years the sums are incurred.

Table 4: Financial Responsibility Table of Funding and Payments –Shows cash inflows and outflows that cover financial responsibility requirements over the project's life.

Table 5: Revenues –Calculates the actual revenues, if any, that are generated by the project in each year of the project's lifespan. The revenues are used in the income statement.

Table 6: Debt –Defines the debt position of the project. It calculates how much debt principal is borrowed in a given year, how much interest is accrued, and how much interest and/or principal is repaid in a given year. It also tracks the total amount of debt the project is carrying in a given year.

Table 7: Taxes –Calculates the tax bill incurred by the project in a given year. To derive this figure, it calculates the tax basis and taxable income in each year and applies the marginal tax rate of the project to all taxable income. The project accumulates net operating losses in the beginning of operations and uses these to lower taxable income when it begins to generate storage revenue from injection.

Table 8: Cash Flow Available to Owners –Shows how much money an owner is able to take out of the project or needs to invest in the project for each year. The sum of the present values, determined by applying the cost of equity as a discount rate, of this full schedule of cash flows is the NPV of the Project.

Table 9: Costs of Different Components of Financial Responsibility –Splits up all of the elements of financial responsibility. These are corrective action, injection well

plugging, emergency and remedial response, PISC and site closure costs not related to the four prior items. This table also shows the schedule of when these costs are incurred in the project.

Table 10: Financial Responsibility Calculations –Shows all cash activity related to meeting financial responsibility requirements. If a Trust Fund or Escrow Account needs to be funded, this table shows the funding schedule as well as the draw down schedule to meet all financial responsibility related payments of the trust fund. Additionally, it shows non trust fund/escrow account schedules for emergency and remedial response. See Section 4.1.6 for a full discussion of financial responsibility.

Table 11: Financial Responsibility Information –Describes how each mechanism of financial responsibility is defined in the model.

Table 12: Miscellaneous Summary of Cash flow Information –Provides other financial information including revenue for storing CO_2 and debt proceeds.

3 Key Inputs

All inputs in the model are in orange cells.

Although all of the orange cells are available for the modeler to edit, the cells most likely to be changed can be grouped into three categories:

1. Project management inputs
2. Activity inputs
3. Geology inputs

1) The project management inputs are located in the tab labeled 'Project_Management.' They will be discussed further in Section 4.1. These inputs cover broader areas, such as scheduling and financial considerations, all of which have an effect on the key outputs discussed in Section 1.1 of this document.

2) Activity inputs are primarily located in the tab labeled 'Activity_Inputs.' This worksheet is substantial and further description of these tables and how the inputs affect the model are in Section 4.2.

3) The geology inputs are located in the tab labeled 'GeolSal.' Details on the geology module methodology are provided within the 'GeolSal' sheet. The geology module has a flexible structure that allows the use of either model-provided data or proprietary data. The modeler should use proprietary data if the model does not include the formation required by the modeler for evaluation or if the modeler has better information than the model does on the specifics of the formation under review. The geologic information contained in this model is generalized at the formation level. For further instructions on where to find the geology inputs see Section 4.3.

4 Detail of Key Inputs

This section will address the key project management and activity inputs.

4.1 Detail of Project Management Inputs

The project management sheet consists of eighteen print-ready pages that have key project management inputs at the top of the page and associated model outputs on the bottom of the page. The inputs shown at the top of each page impact both the output at the bottom of the same page and the key outputs of the model discussed in Section 1.1 of this document.

4.1.1 Break-Even Price (6) and Evaluate Formations (Exhibit 7) Macros

The main objective of this model is to solve for the first year break-even price to store a tonne of captured CO_2. When looking at one formation only, a model can provide the first-year break-even price or, with a price input, solve for the NPV and IRR of the project.

The changes for both types of analysis are done in the 'Project_Management' worksheet via the 'Find CO_2 Price that Makes NPV Zero.' In Column N, the modeler can click the grey button to run a macro that sets the first-year price of CO_2 to the break-even price, as shown in 6. This price solves for an NPV = 0 to the second significant digit of the CO_2 price. Therefore, there will be an NPV displayed, but it is effectively 0 for analytical purposes. The macro will also show the IRR of the project at 'Find CO_2 Price that Makes NPV Zero,' which is a break-even NPV analysis that solves for the price that an individual project in a specific formation must charge in its first year in order to return an effective NPV of zero. The NPV will not actually be zero, it will be the smallest positive number that can be obtained in solving for a break-even CO_2 price to the second significant digit. For example, if the break- even analysis is run and the CO_2 price is $20.02 with an NPV of $95,000, the project would return a negative NPV if the modeler charged $20.01. Therefore, it would be safe to call $20.02 the NPV zero price since the positive NPV is simply a rounding issue.

If the modeler wants to know the NPV of a project for a price different from the break-even value, then the modeler should enter that price value in the orange colored cell (P15). The resulting NPV and IRR will be posted in the grey cells below.

The 'Evaluate Formations' Macro, as shown in Exhibit 7, is an output where the single formation cost analysis is replicated for each reservoir formation posted in the geologic database and read by the model, providing for multiple cost analysis. This output is posted to the 'ResSum1' tab. Data posted in this newly generated worksheet not only includes the results of the break-even cost analysis, but also real, nominal, and escalated cost data for each formation; the total amount of CO_2 stored in the formation; and rates of injection as well as other descriptive detail about the formation for a modeler to review. The first year break-even cost data provided here can be used to construct a CO_2 storage potential cost supply curve.

Another important modeling selection here is selection for 'Control for formation structure'. A value posted in cell Q30 per the values listed on the adjoining table will allow the modeler to select the suit of structural settings to be cost modeled for each formation reservoir in the geologic database.

When the 'Evaluate Formations' Macro is run, the macro will save the run results in a separate Excel file presently named 'xNewResultFile.xlsm' as seen in cell Q34 of the Project Management worksheet (Exhibit 7). To function properly, this file needs to be saved in the same directory as the cost model. A new file can be created but the name as to be posted in cell Q34. If the model is unable to post the results to xNewResultsFile.xlsm (it may be in a different directory, incorrectly labeled or simply not saved) the model will show an error message when running the macro; however, the user can still access the results on the 'ResSum1' tab within the model. Just close out the error messages.

Exhibit 6 Break-even price macro

Find CO2 Price that Makes NPV Zero

Control for type of injection project	0	Set to 1 for injecting CO2 to fill max. possible plume area		
		Any other number indicates inject specified mass of CO2		
	Base year	Proj start	Inj start	
Year	2008	2011	2017	
First Year Price of CO2	8.06	8.81	10.52	$/tonne
Net Present Value (NPV) of project		10,110,605		2011$
Internal rate of return (IRR) for project		14.1%		

Exhibit 7 Evaluate formations macro

Run Title:	Baseline Case

Evaluate Formations

First formation number:	1
Last formation number:	226
Formation just processed:	

Control for formation structure	0	Set to 1 for General structure
		Set to 2 for dome, anticline, 2 inclines and flat
		Set to 3 for dome, anticline and flat
		Other number for dome, anticline and regional dip
Name of workbook to store ResSumn sheet	xNewResultsFile1.xlsm	

The 'Evaluate Formations' macro will automatically save a record of the output for each formation, so there is no need to do that manually or with additional macros. The macro will automatically create a new sheet with the results in the file 'xNewResultsFile.xlsm' listed in cell Q34, as long as such a file exists in the same folder as the model.

4.1.2 Inputs to Geology Module (Exhibit 8)

The description below provides information on the inputs to the geology module in the saline cost model. Saline storage operations are simply the injection of CO_2 although the saline cost model now provides for the production, treatment, and disposal of water. The injection of CO_2 and the handling of water are two separate systems. Some data entries for the Geology Module can be accomplished through locations in the Project Management Module. To model a specific or single site ('Find CO_2 Price that Makes NPV Zero' macro button), the modeler can enter a formation number in cell Y5, as shown in Exhibit 6. Along with selecting a specific formation, a structural setting (cell Y11) and a storage coefficient value (cell Y8) also need to be selected.

In the geologic database found in the 'Geol DB Sal' tab, formation numbers are listed in Column A and associated formation names are listed on Column B. Storage coefficients are found in the 'Geol Sal' tab within the Attachment A table. Storage coefficients are listed by structural setting and depositional environment. A depositional environment is posted for each reservoir formation in the geologic database. The modeler can determine the range of storage costs for a particular reservoir formation by sequentially selecting each structural setting and probability of storage coefficient.

The structural setting (general, anticline, dome, 10 degree incline, 5 degree incline, flat, and regional dip) is an input for the user to change. Each structural setting represents a percentage of the total areal extent of each reservoir formation listed in the geologic database. Presently, dome and anticline each represent 1.25 percent of the areal extent (USGS 2011). The remaining area is divided equally between ten and five degree dip and flat, each representing 32.5 percent of the areal extent. The areal extent for regional dip is sum of 10 degree incline, 5 degree incline, and flat, 97.5 percent of a particular reservoir formation. Except for cell Y19, these percentages can be edited by the modeler in cells Y15 through Y21. The value in cell Y19 is determined by selecting a value for "Control for formations structure' in cell Q30. The modeler can also restrict the volume of a formation reservoir available for storage by entering a 'Perc. Avail.' value in cells AA15 through AA21. A 'Perc. Avail.' of less than 100 percent restricts the volume of storage capacity available for an injection project.

To account for surface constraints that might limit the area that a project can cover, the modeler can enter a maximum surface area of the injection project. This value is entered in the 'Project Management' sheet in cell Y32 and is tied to the areal extent of the CO_2 plume uncertainty boundary. This constraint is meant to deal with anthropogenic constraints at the surface rather than geologic constraints in the subsurface. Any project where the set amount of CO_2 for injection would push the extent of the CO_2 uncertainty boundary beyond this areal limit will use a lower amount of injected CO_2. For example, if modeling an annual injection rate of 3.2 million metric tonnes and the areal extent of the CO_2 plume uncertainty boundary for the cumulative 96 million metric tonnes injected over 30 years exceeds this set limit, the model will modify the annual injection rate so that the cumulative mass of injected CO_2, something less than 96 million metric tonnes, fits within the set areal limit. The calculated first year break-even price to store a tonne of captured CO_2 will be for this lower mass of CO_2 injected. Selected and modeled injection rates and cumulative mass of CO_2 stored are presented in Column AN in the Geologic Module Output table.

Below the cells illustrated in Exhibit 8 is data pertaining to the rate of CO_2 injection and CO_2 plume area and other areas, which is pulled from the geologic module found in the 'Geol Sal' tab. This information is reservoir-formation-specific per the information present in cell Y5 and calculated by the model. It is pulled from the geologic database and posted in this table for convenience.

Exhibit 8 Inputs to geology

Inputs to Geology Module				
Formation Number				
Select injection formation number	Form_num	278	Rose Run4	
Storage Coefficient Inputs				
Probability level for storage coefficients	E(E)_Pvalue	P50	Options: P10, P50, P90	
Structure Inputs				
Select structure	Form_struct	Reg_dip	Options: General, Anticline, Dome,	
			Incline_10deg, Incline_5deg, Flat, Reg_dip	
General Characteristics of Structures				
Structure		Perc. of Form.		Perc. Avail.
Dome	PForm_Dome	1.25%	PAvail_Dome	80%
Anticline	PForm_Anticl	1.25%	PAvail_Anticl	80%
Incline 5 Degrees	PForm_Incl5	32.50%	PAvail_Incl5	40%
Incline 10 Degrees	PForm_Incl10	32.50%	PAvail_Incl10	40%
Flat	PForm_Flat	97.50%	PAvail_Flat	40%
Regional Dip	PForm_Reg_dip	97.50%	PAvail_Reg_dip	40%
General	PForm_Gen	100%	PAvail_Gen	40%
Note: General indicates a composite of all structures				
Perc. of Form. Is the percent of the formation that has the indicated structure				
Perc. Avail. Is the percent of the structure that is available for storing CO2				
Multiplier for Storage Coefficient				
Control parameter for influence of R&D	ConStorCoef	0	Options: 0 indicates no R&D influence	
			or a multiplier of 1	
			1 indicates R&D influence, for multipliers	
			see Section 3.5.5 in Geol Sal	
Nominal Maximum Surface Area for Injection Project and Control Parameter for Applying Maximum Surface Area				
Nom. max. surface area for inject. proj.	Aprojmaxnom	100	mi2	
or largest contiguous area where pore		64,000	acres	
space rights can be aquired;		258,973,535	m2	
maximum size of AOR				
Control parameter for how to apply the	AmaxnomCon	0	Options: Nominal max. surf. area for an	
nominal maximum surface area for an			injection project is applied as follows:	
injection project			0 -- CO2 Plume Uncertainty Area (default)	
			1 -- 3D Seismic Area	
			2 -- max(3D Seis. Area, CO2 Pr. F. AOR)	
Maximum CO2 Injection Rate Based on Mechanics of Well				
Max CO2 inject rate per well (mechanics)	qwell_mech_dy	3,660	tonnes/day	
(daily max expressed as annual rate)	qwell_mech_yr	1.336	Mtonne/yr	
(corresponding average annual rate)	qwell_mech_avyr	1.069	Mtonne/yr	
(min. operational inject. wells needed)	NumOpInjWmin	3		

4.1.3 Project Timeline (Exhibit 9)

The project timeline sets the foundation of the overall project schedule. The modeler can select a beginning year on or after 2008 and the duration of each stage of the project. The total life of the project (or sum of the durations across all stages) cannot exceed 200 years. Project timeline is located between columns AV to BE.

Exhibit 9 Project timeline

Project Stage Timeline: Enter the beginning calendar year of the project, as well as the duration of each stage of the project to define the project timeline.					Year Project Begins:
					2011
	Duration (Yrs)		**Begin Year**	**End Year**	**Calendar Years:**
Regional Evaluation	1	**Regional Evaluation**	1	1	2011 - 2011
Site Characterization	3	**Site Characterization**	2	4	2012 - 2014
Permitting	2	**Permitting**	5	6	2015 - 2016
Operations	30	**Operations**	7	36	2017 - 2046
PISC and Site Closure	50	**PISC and Site Closure**	37	86	2047 - 2096

Impact of inputs holding all other model inputs constant

Start year: This is the year is which regional evaluation begins. The cost of storage is calculated for the year 2008. This cost is escalated, at the selected rate of inflation, to subsequent years. The cost of storage for a beginning year of 2011 will be greater than if the project began in 2008.

Regional evaluation: One year is considered sufficient time to evaluate the geology over a large enough area that, hopefully, will provide the opportunity for several prospective storage sites. All of the work is done with existing data.

Site characterization: There is a fair amount of risk in selecting a site that will be successfully characterized. Three years is considered a minimum time to accomplish this, more time is needed if the initial site(s) are unsuccessful.

Permitting: Two years is a minimum time period for permitting. One year is needed for the Environmental Protection Administration (EPA) to review and approve the application for permit. With permit approval, the injection wells are drilled, tested, and completed. Data from these wells are incorporated in the submitted 'Plans' to confirm the data already presented. Updated plans are presented to EPA for final approval to begin injection.

Operations: The length of injection operations needs to match the project life of the source; 30 years is a typical time span. The plans submitted for application for the Class VI permit are acted on here. Corrective action is performed. The monitoring, verification, and accounting (MVA) plan is followed. An area of review (AoR) review is performed at least every five years. Financial responsibility costs are updated annually.

PISC and site closure: The regulatory default time period is 50 years per Class VI regulations. Modeling a shorter time span will lower the break-even price by reducing the number of years costs are incurred for this particular project stage. There is also the possibility that more time may be required here if non-endangerment can't be established. The MVA plan for Operations can be utilized or modified for PISC.

Long-term Stewardship: This stage is outside the scope of the Class VI regulations and it is not modeled. Its time frame is unknown but could, theoretically, last for the rest of civilization. The model provides for collection of money during operations for a long-term stewardship trust fund.

The 'operations' stage is the only time period when cash flow is positive. All costs are ultimately paid for from operations. Reducing the time period for site characterization and permitting lowers costs and provides for earlier earnings from operations. Reducing the time spent on PISC will significantly reduce costs and impacts on financial responsibility.

CO_2 Injected During Project

The modeler has an option to edit the total annual injection rate, or the 'Average Tonnes of CO_2 Injected per Year' in cell BC14. The only revenue that the project collects is based on how much CO_2 is injected, so increasing the annual volume of CO_2 injected will lower the break-even price. There is an economies-of-scale benefit to injecting more tonnes of CO_2 over its fixed costs. Absolute costs will also go up because injecting more CO_2 results in an increased investment in monitoring activities, especially monitoring well drilling and seismic.

The 'Multiplier for annual to maximum daily rate of CO_2 injection' accounts for the capacity factor of the power plant. When the plant is online, emissions are generated 24/7, which will exceed the average daily rate calculated by dividing the annual volume injected by 365. A plant with an 80 percent capacity factor has a multiplier of 1.25. The average daily injection rate over a year for the project posted in Exhibit 10 is 8,767 tonnes of CO_2. The maximum daily rate is 10,959 tonnes per day. This maximum rate needs to be accounted for by the injection wells of the storage project.

Values posted for 'The Average Tonnes of CO_2 Injected per Year' and 'Multiplier for annual to maximum daily rate of CO_2 injection' are picked up by the Geology Module to calculate injectivity and the number of injection wells needed for the project.

Exhibit 10 CO_2 injected during project

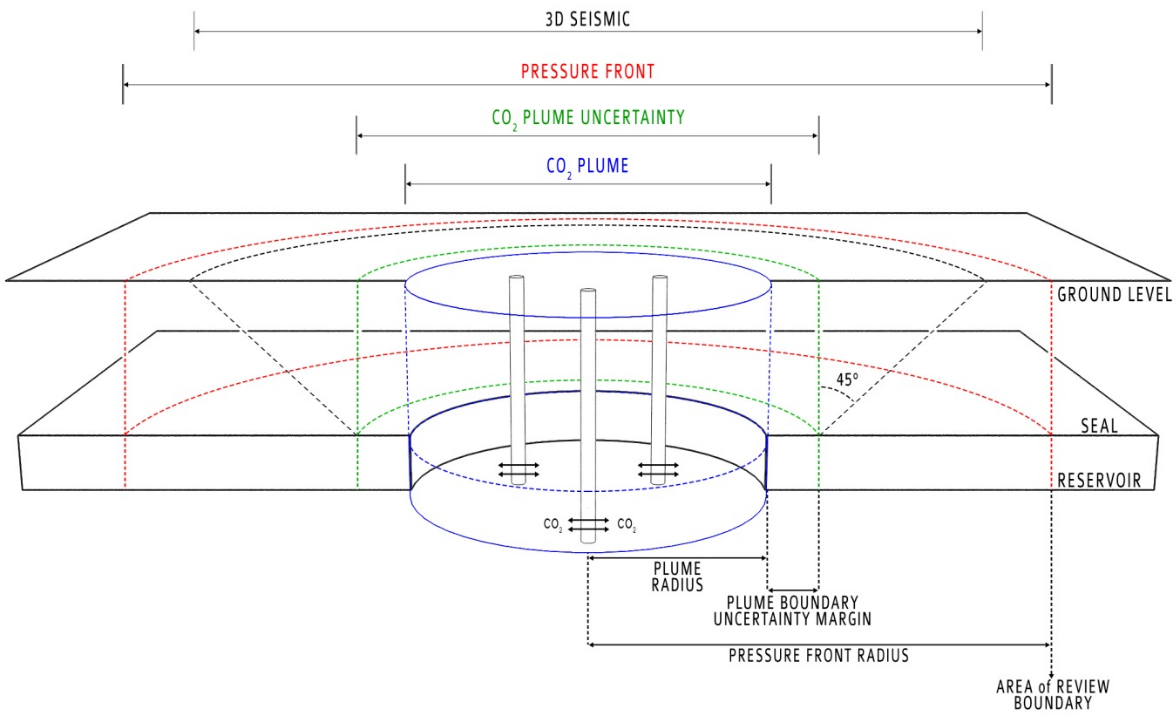
CO2 Injected During Project		
Nominal average tonnes of CO2 injected per year	3,200,000	tonne/year
Multiplier for annual to maximum daily rate of CO2 injection	1.250	multiplier
Area Related Inputs		
CO2 Plume Uncertainty Area Multiplier (applied to CO2 Plume Area)	1.75	
CO2 Pressure Front AOR Multiplier (applied to CO2 Plume Uncertainty Area)	10.00	

Area Related Inputs

The model calculates the areal extent of the CO_2 plume based on mass of CO_2 injected over injection operations period, height of the reservoir, porosity, storage coefficient, and density of the CO_2 at reservoir conditions. This is a relatively precise value for a subsurface situation with some level of uncertainty. The exact boundary of the CO_2 plume is unknown. This uncertainty is accounted for by the CO_2 Plume Uncertainty Area Multiplier value input by the modeler in cell BC18. This multiplier is applied to the CO_2 plume area.

The boundary defining the pressure front is also unknown and not specifically calculated by the model. The CO_2 Pressure Front AoR Multiplier accounts for the pressure front and this value is entered in cell BC19. This multiplier is applied to the CO_2 Plume Uncertainty area.

Exhibit 11 Boundaries calculated by model



Calculated Quantities

Mass of CO_2 Injected

Tonnes of CO_2 injected per day on average is the annual mass of CO_2 injected selected by the modeler divided by 365 days.

Maximum daily rate of CO_2 injected takes into account that the source will operate 24/7 for most of the year and that the storage operations needs to be able to handle delivery of this daily mass of captured CO_2. The multiplier entered in cell BC15 accounts for the capacity factor.

CO_2 Plume and Related Areal Quantities (see Exhibit 12)

CO_2 Plume Area: Calculated area based on total mass of CO_2 injected and the porosity, storage coefficient, height of reservoir, and density of CO_2 at reservoir conditions. The maximum plume area is pulled in from the 'Plume & Well Schedule' tab.

CO_2 Plume Uncertainty Area: A multiple of the CO_2 Plume Area based on 'Multiplier' entered above. Value posted here pulled in from the 'Plume & Well Schedule' tab.

CO_2 Pressure Front AoR: A multiple of the CO_2 Plume Uncertainty Area based on 'Multiplier' entered above. Value posted here pulled in from the 'Plume & Well Schedule' tab.

Maximum Area for 3-D Seismic: Area based on a projection at an angle of 45^o from the intersection of the CO_2 Plume Uncertainty Boundary and the top of the storage reservoir. The angle of this projection can be changed in cell BZ19 for '2-D and 3-D Seismic Inputs'

Maximum Length of 2-D Seismic: Length based on a projection at an angle of 45^o from the intersection of the CO_2 Plume Uncertainty Boundary and the top of the storage reservoir. The angle of this projection can be changed in cell BZ20 for '2-D and 3-D Seismic Inputs'

Exhibit 12 Calculates quantities & CO_2 plume and related areal quantities

Calculated Quantities		
Mass of CO2 Injected		
Tonnes of CO2 Injected per day on average	8,767	tonne/day
Maximum daily rate of CO2 injection	10,959	tonne/day
Total Tonnes of CO2 Injected	96,000,000	tonne/project
CO2 Plume and Related Areal Quantities		
CO2 Plume Area (best estimate for maximum areal extent of CO2 plume)	8.9	mi2
CO2 Plume Uncertainty Area (maximum extent of CO2 plume with uncertainty)	15.6	mi2
CO2 Pressure Front AOR (maximum extent of pressure front)	155.6	mi2
Maximum Area for 3D Seismic (Based on CO2 Plume Uncertainty Area)	50.9	mi2
Maximum Length for 2D Seismic (Based on CO2 Plume Uncertainty Area)	8.0	mi

4.1.4 Surface Equipment Input (Exhibit 13)

Exhibit 13 Surface equipment inputs

Surface Equipment Inputs for Calculating Capital and O&M Costs		
Inputs for feeder pipeline that transports CO2 from main CO2 pipeline to the saline storage site		
Length of feeder pipeline (Enter 0 for no pipeline)	1.68	mi
Inputs for pump to boost pressure of CO2 at saline storage site		
Is a pump needed to boost the pressure of CO2? (enter yes or no)	yes	
Pressure at pump inlet	1200	psig
Pressure at pump outlet	2200	psig
Inputs for network of pipes within site that distribute CO2 from central header to injection wells		
Multiplier that translates CO2 plume radius to length of pipe	0.333	

Data inputs in the surface equipment section provide for estimation of a pipeline network that takes delivery of the captured CO_2 at the storage site 'fence line' or 'gate' and distributes it to the injection wells. The length of the feeder pipe (cell BH5) is half the diameter of the calculated CO_2 plume area. The CO_2 is distributed from a central location at the storage site.

A booster pump will be necessary for the storage site as the operator will not want to rely on the delivered pipeline pressure. There will be some pressure drop to the delivery point depending on the distance from the last booster pump in the delivery pipeline. Pressure at the pump outlet (cell BH10) is the pressure delivered to the injection well head.

The multiplier that translates CO_2 plume radius to length of pipe provides for the distribution network delivering CO_2 to each of the injection wells.

This is all an approximation based on the calculated CO_2 plume radius to provide for a surface pipeline network, and associated costs, for a storage project

4.1.5 Well-Related Inputs and Outputs (Exhibit 14)

The description below provides examples and explanations for characterization (strat-wells), injection, production, disposal, and monitoring well-drilling inputs to the model and modeled outputs regarding the number of wells drilled. Unless defined, all other items are inputs. Except for injection wells, this is where the modeler can 'turn off' or 'turn on' a particular type of well to be modeled or not modeled for costs.

Characterization (Strat Test), Injection, Production, and Disposal Wells:

This table was modified to incorporate modeling of risk during site characterization to account for failure of *a selected site(s) to meet criteria for a suitable CO_2 storage site.*

Well Types

Number of sites selected for characterization (1 strat test well and 2-D seismic): '4' means that over the period of time selected for site characterization, four sites well be characterized and each will have a strat-well drilled and 2-D seismic data acquired. A strat-well is a well drilled to

Exhibit 14 Well-related inputs

Well-Related Inputs and Outputs						
Characterization, Injection, Production and Disposal Wells						
Well Type	**Units**	**Value**				
Number of sites pre-charac. (1 strat well & 2-D seis.)		4				
Number of lines for pre-charac. 2-D seismic		2				
Number of Total Strat Test Wells on Selected Site	wells	2				
Strat-wells converted to injection wells	wells	0				
Strat test wells converted to in reservoir, above seal or dual completed monitoring wells		In reserv	Above seal	Dual compl		
	in CO2 Pl	0	0	0		
	in Pres Fr	0	0	0		
Number of Strat Test Wells	wells	5				
Number of Injection Wells	wells	4				
Number of Water Production Wells	wells	2				
Number of Water Disposal Wells	wells	2				
Water Production and Injection Status (enter On or Off)		On	For water management inputs, see sheet "Water"			
Monitoring Well Inputs						
	Well Density		**Number of Wells**			
Monitoring Well Type	**Units**	**Value**	**Min. Start**	**Min. End**	**Max. No.**	**Fixed No.**
Mon. Wells In Reserv. in CO2 Plume Unc Area	mi2/well	4	1	2	0	0
Mon. Wells In Reserv. in Pres. Front	mi2/well	50	1	2	0	0
Mon. Wells Above Seal in CO2 Plume Unc Area	mi2/well	4	1	2	9999	0
Mon. Wells Above Seal in Pres. Front	mi2/well	50	1	2	0	0
Mon. Wells Dual Comp. in CO2 Plume Unc Area	mi2/well	4	1	5	9999	0
Mon. Wells Dual Comp. in Pres. Front	mi2/well	50	1	2	2	0
Monitoring Wells Groundwater	wells/inj. well	1	Note: For no wells, set following values to zero:			
Monitoring Wells Vadose Zone	wells/inj. well	1	Strat Test Wells conv to mon wells,			
			Max. No. and Fixed No.			
Corrective Action			*Well counts (not noted as pressure front) are			
Density of deep wells needing CA	wells/mi2	0.25	based on CO2 plume uncertainty area			
Density of water wells needing CA	wells/mi2	0.75				

gather data on the stratigraphic section present in the area of the proposed CO_2 storage site. In the model, this well is drilled 500 feet deeper than the injection well.

Number of lines for each site characterized (2-D seismic): '2' is the number of 2-D seismic lines shot of each of the sites selected (four sites in this example) for site characterization. The successfully characterized site will also have 3-D seismic data acquired over its areal extent. This selection is made in the 'Activity_Inputs' worksheet, Table 3.8 Surface Seismic.

Number of total strat test wells on selected site: '2' means the site that is successfully characterized will have a second strat-well drilled.

Strat test wells converted to injection wells: Provides the option of converting strat test wells to either an injection well or various types of monitoring wells.

Number of strat test wells: '5' (an Output) means that over the four sites selected for site characterization, three unsuccessful sites will each have one strat-well drilled and the successful site will have two strat-wells drilled.

Number of injection wells: '19' (an Output) This is the number of injection wells, determined by the model, needed to inject the mass of CO_2 on an annual basis without exceeding the reservoir pressures per the Class VI permit. The number of injection wells provides for injection of the maximum daily capture rate per the 'capacity factor' as well as providing for spare capacity to account for well maintenance while an injector is shut-in.

Number of water production: (an Output) Calculated by the model based on the mass of water to be withdrawn from the storage reservoir. See 'Water' discussion on page 78.

Number of water disposal: (an Output) Calculated by the model based on the mass of water to be disposed of (injected). See 'Water' discussion on page 78.

Water Production and Injection Status: Modeling for the withdrawal of water from the storage reservoir is initiated from the Well-Related Inputs and Outputs portion of the 'Project_Management' module. The on-off switch is in Cell BN17.

Monitoring Well Inputs

Monitoring Well Type *(Column BL)*

Mon. Wells In Reserv. in CO_2 Plume Unc Area: Monitoring wells in reservoir within the CO_2 plume uncertainty area.

Mon. Wells In Reserv. in Pres. Front: Monitoring wells in reservoir within pressure front. These wells are outside of the CO_2 plume uncertainty area.

Mon. Wells Above Seal in CO_2 Plume Unc Area: Monitoring wells above the seal within the CO_2 plume uncertainty area.

Mon. Wells Above Seal in Pres. Front: Monitoring wells above seal within pressure front. These wells are outside of the CO_2 plume uncertainty area.

Mon. Wells Dual Comp in CO_2 Plume Unc Area: These wells are drilled to the reservoir and completed in the reservoir as well as above the seal within the CO_2 plume uncertainty area. This dual completion provides for monitoring two separate intervals from the same well.

Mon. Wells Dual Comp in Pres. Front: These wells are drilled to the reservoir and completed in the reservoir as well as above the seal within the pressure front area. This dual completion provides for monitoring two separate intervals from the same well.

Monitoring wells groundwater: These wells monitor shallow underground sources of drinking water (USDWs) and are drilled in close proximity to the injection well.

Monitoring wells vadose zone: These wells monitor the vadose zone and are drilled in close proximity to the injection well.

All monitoring wells are specified (location and depth) in the Testing & Monitoring Plan submitted upon application for a Class VI permit.

Well density: Units & Values *(Column BM-BN)*

Units here are either square miles per well (mi2/well) or wells per injection well (wells/inj. well). Value is the number of square miles or number of wells per injection well.

Deep monitoring wells to the storage reservoir or above the seal will have a well spacing in square miles. The example here (Exhibit 14) is 4 square miles per monitoring well within the plume uncertainty area or 50 square miles for monitoring wells between the plume uncertainty boundary and the pressure front boundary. Well spacing is the areal extent over which one monitoring well draws a representative sample. Notice that monitoring wells drilled in the reservoir within the plume have 4 mi^2 spacing and are dual completed. Monitoring wells drilled above the seal with the plume also have 4 mi^2 spacing. Overall, monitoring wells above the seal have a well spacing of 2 mi^2. The number of monitoring wells drilled depends on the areal extent of the CO_2 plume uncertainty area and the pressure front.

Groundwater and vadose zone monitoring well count is tied to the number of injection wells drilled. It is assumed that these wells will be placed in close proximity to the injection well(s). In Exhibit 14, one groundwater and one vadose monitoring well is drilled per CO_2 injection well.

Number of Wells *(Column BO to BR):*

Modeler input here controls the number of monitoring wells drilled for each Monitoring Well Type (Column BL) for the storage project modeled.

Min. Start: the minimum number of monitoring wells to be drilled at the beginning of operations.

Min. End: the minimum number of monitoring wells that will be drilled by the end of operations.

Max. No.: Value posted here (cells BQ21 to 26) can be used to turn the well type on or off. To turn off a monitoring well type, enter '0.' To turn on, enter a specific value equal to or greater than the Min End value. To allow the maximum number of wells possible, enter '9999.'

Min. Start, Min. End and Max. No. work in conjunction with the Well Density value to assure that a minimum number of monitoring wells are drill even if the CO_2 plume uncertainty area or pressure front area is smaller than the well spacing. With '9999' entered for Max. No., it also assures that number of monitoring wells drilled is not restricted.

Fixed No.: The user may choose to set a fixed number of monitoring wells to be drilled regardless of the areal extent of the CO_2 plume. A value posted here overrides the Well Density value (Column BN). Regardless of plume size, a fixed number of monitoring wells will be drilled.

The well-related inputs drive costs significantly, so the modeler ultimately determines how much monitoring well drilling is performed on a specific site in the formation under review. The more well drilling (i.e., smaller well spacing), the higher the break-even price will be in order to cover greater well drilling as well as O&M and plugging costs. Groundwater and vadose zone wells are tied to injection wells; better injectivity reduces these costs.

Corrective Action

These values are pulled into the 'Activity_Inputs' sheet where the cost of corrective action is applied to the well count established here. Application of these costs can be turned on or off, and the cost frequency can be adjusted.

Density of deep wells: '0.25' – units of wells per square mile

Density of water wells: '0.75' – units of wells per square mile

Corrective Action is part of the Area of Review Plan submitted upon application for a Class VI permit. Deep wells are those wells that penetrated the seal or reservoir. A '0.25' wells means that one well per 4 square miles will require corrective action to repair an old leaky well and prevent endangerment of USDWs.

4.1.6 2-D and 3-D Seismic Inputs (Exhibit 15)

The description below provides examples and explanation for the 2-D and 3-D seismic inputs of the model. The examples shown relate to the saline model.

Exhibit 15 2-D and 3-D seismic

2D and 3D Seismic Inputs					
3-D Seismic Costs					
Basic cost for survey		\$/mi2	160,000		
Additional cost for processing field data			10%		
Schedule for 3-D Seismic					
	Enter zero to use default values. For a One-Time cost set the Begin Year=End Year.				Frequency (yrs) for Application of 3-D
	User Input Selection		Years that will be used		
Stage	**Begin Year**	**End Year**	**Begin Year**	**End Year**	
Site Characterization	0	0	2	4	3
Permitting	0	0	5	6	
Operations	0	0	7	36	5
PISC and Site Closure	0	0	37	86	5
Angles Needed for Adequate Resolution of 3-D and 2-D Seismic Images					
Angle from CO2 Plume AOR edge to surface needed for 3-D seismic				degrees	45
Angle from CO2 Plume AOR edge to surface needed for 2-D seismic				degrees	45
Fraction of Maximum 3D Seismic Area and 2D Seismic Length at Start of Monitoring					
Fraction of CO2 Plume Uncert. Area that is starting area for 3D seismic monitoring					0.5
Frac. of CO2 Plume Uncert. Area that provides starting length for 2D seis. monitoring					0.5

3-D Seismic Costs

Basic cost for survey: '160,000.00' per square mile is the current cost used in the model for acquiring 3-D seismic data. It is a generic value. Cost may change for several reasons, such as application of different technology, improved technology or better field logistics such as open prairie or farm land.

Additional cost for processing field data: '10%' –a percentage of the data acquisition cost to cover data processing costs. The value applied here is a generic value.

Schedule for 3-D Seismic

Within this table, the user is able to input beginning and end years or use values that are taken from the 'Activity_Inputs' page for four stages: site characterization, permitting, operations, and PISC and site closure. An input of '0' will give the default value. Frequency, in years, for application of 3-D seismic is given for three stages. For site characterization, a '3' means 3-D seismic is acquired in the third year of site characterization. The '5' for operations and PISC/site closure means 3-D seismic is acquired every five years for AoR and every five years per PISC plan, respectively. It is not expected that seismic data will be acquired during Permitting.

As discussed in other sections, there are three areas that are relevant to various costs (see Exhibit 11). The areal extent of the CO_2 plume is the primary cost driver. The plume uncertainty area, a multiple of the CO_2 plume area, drives MVA costs; the 3-D seismic area depends on the plume uncertainty boundary and drives 3-D and 2-D seismic data acquisition cost; and the pressure front, a multiple of the uncertainty boundary, drives monitoring well costs for these wells drilled between the CO_2 plume uncertainty and pressure front boundaries. Depending on the multiplier for the pressure front, the 3-D seismic area may or may not encompass the pressure front.

Angles needed for Adequate Resolution of 3-D and 2-D Seismic Images

Angle measured at CO_2 plume uncertainty boundary (see Exhibit 11) for 3-D and 2-D seismic data acquisition: '45' – 45 degree angle. This extended area (3-D) or distance (2-D) is needed to build fold and properly image the plume in the reservoir. The seismic grid (3-D) or line (2-D) must begin some distance beyond the perceived boundary of the plume in the reservoir. This distance is determined by projecting the assumed plume boundary at 45 degrees from the top of the reservoir to the surface. This angle value is a generic value.

Fraction of Maximum 3-D Seismic Area and 2-D Seismic Length at Start of Monitoring

When injection of CO_2 begins, the areal extent of the CO_2 plume will grow through time. If 3-D seismic or 2-D seismic are selected by the user as methods to monitor the location of the CO_2 plume over time, then the area needed for 3-D seismic or the length needed for 2-D seismic will also change over time. The area needed for 3-D seismic imaging at a particular time depends on the estimated area of the CO_2 plume at that time, the CO_2 Plume Uncertainty Area Multiplier (see Exhibit 10) and additional area needed for 3-D seismic. The estimated area of the CO_2 plume multiplied by the CO_2 Plume Uncertainty Area Multiplier yields the CO_2 Plume Uncertainty Area at that time. This is the area that is targeted for imaging with 3-D seismic. However, a larger area than the target area must be used in 3-D seismic to ensure the target area is captured with sufficient resolution. This area will also depend on how the injection wells are spaced relative to each other. The upshot is that even if the anticipated CO_2 plume area around each injection well is relatively small, a much larger area must be used for 3-D seismic. To ensure that sufficient area is used in the 3-D seismic imaging process, the required area is calculated as follows. First, the CO_2 Plume Uncertainty Area at any given time is assumed to be a linear function of the time during injection. The CO_2 Plume Uncertainty Area at the start of injection is assumed to be a fraction of the maximum CO_2 Plume Uncertainty Area and this area increases linearly with time to the maximum CO_2 Plume Uncertainty Area at the end of injection. The user specifies the fraction of the maximum CO_2 Plume Uncertainty Area to be used at the start of injection ("Fraction of CO_2 Plume Uncertainty Area that is starting area for 3-D seismic monitoring" in Exhibit 15). Second, the 3-D Seismic Area at this time is calculated as the CO_2 Plume Uncertainty Area plus additional area needed to image the target area. This additional area is a function of the angle discussed above and the depth to the reservoir (see Exhibit 11).

The length or distance needed for 2-D seismic imaging at a particular time depends on the length of the CO_2 Plume Uncertainty Area (see Exhibit 11) and additional distance needed for 2-D seismic. The length of the CO_2 Plume Uncertainty Area is estimated assuming this area is a circle and the length is the diameter of the circle. This is the length that is targeted for imaging with 2-D seismic. However, analogous to 3-D seismic, a longer distance than the target distance must be used in 2-D seismic to ensure the target region is captured with sufficient resolution. To ensure that sufficient distance is used in the 2-D seismic imaging process, the required distance is calculated as follows. First, the CO_2 Plume Uncertainty Area at any given time is assumed to be a linear function of the time during injection. The CO_2 Plume Uncertainty Area at the start of injection is assumed to be a fraction of the maximum CO_2 Plume Uncertainty Area and this area increases linearly with time to the maximum CO_2 Plume Uncertainty Area at the end of injection. The user specifies the fraction of the maximum CO_2 Plume Uncertainty Area to be used at the start of injection for the 2-D seismic calculations ("Fraction of CO_2 Plume Uncertainty Area that provides starting length for 2-D seismic monitoring" in Exhibit 15). Second, the target length for 2-D seismic at a specific time is calculated as the diameter of the CO_2 Plume Uncertainty Area at that time assuming the CO_2 Plume Uncertainty Area is a circle. Third, the actual length for 2-D seismic at this time is calculated as the target length plus additional distance needed to image the target length. This additional distance is a function of the angle discussed above and the depth to the reservoir (see Exhibit 11).

Similar to the well drilling costs, the 3-D seismic costs are significant to the project. In Exhibit 15, the modeler inputs the acquisition cost per square mile, data processing costs as a percentage of acquisition costs, and information on the frequency of seismic data acquisition during site characterization, operations, and PISC and site closure. When 3-D seismic is performed during site characterization, it is assumed to be over the entire 3-D Seismic Area (see Exhibit 11).

The cost of 2-D seismic data acquisition and data processing is entered in Table 3.8 in the Activity Cost Module. When 2-D seismic is performed during site characterization, it is assumed to be over a length that corresponds to the diameter of the entire 3-D Seismic Area assuming this area is a circle.

4.1.7 Inputs Related to Financial Module (Exhibit 16)

The description below provides information on the inputs to the financial module portion of the saline model that can be entered from the Project Management module.

To calculate a break-even price, this model uses a financial module that takes tax, debt, and equity-required returns into consideration. The Inputs to Financial Module table shown in Exhibit 16 is where a modeler can edit those inputs.

The lower the capitalization, the lower the break-even price as long as the cost of debt (interest rate of project debt) is lower than the cost of equity. The tax rate will also reduce the break-even price if it is lowered by decreasing the overall tax bill. The escalation rate in this model is universal; it will escalate all costs and revenues at the same rate.

Percent equity (remainder is debt): Debt/Equity ratio will depend on the type of business operating the CO_2 storage facility. A 45/55 debt/equity ratio as seen in Exhibit 16 reflects a high risk Investor-Owned Utility (IOU) (NETL 2011). An oil field service company, a pipeline company, or other large company may have different debt/equity ratios.

Cost of equity: The cost of equity in the model is assumed to be 12%, which reflects a high-risk IOU business scenario. Under the NPV=0 analysis, for which the model is most often used, the cost of equity is equal to the internal rate of return.

Cost of debt: The 5.5% value entered reflects an IOU business scenario; this value is LIBOR plus a few percentage points.

Tax rate: The 38% value entered covers corporate Federal and State tax rates.

Escalation rate: The 3% value entered applies to all costs posted in the 'Back-End Cost Items' tab to calculate nominal values. The first year break-even price to store a tonne of CO_2 is escalated at this rate.

General and administrative (G&A) factor: This value accounts for under estimation of G&A costs.

Site characterization failure contingency: To account for risk associated with successfully selecting a potential storage site that will survive site characterization and be submitted for Class VI permit. Zero was entered because another method was adopted to model site characterization risk.

Process contingency factor: To account for underestimation of the cost in installing the technology with subsequent successful trouble-free operation. This cost is assessed on all monitoring technology items.

Project contingency factor: To account for under estimation of costs to successfully complete the project. This cost is assessed on all capital costs.

Exhibit 16 Inputs to financial module

Inputs Related to Financial Module			
			Defaults
Percent Equity (remainder is debt)	55.0%	Capitalization	55.0%
Cost of Equity	12.0%	%/yr	12.0%
Cost of Debt	5.5%	%/yr, Interest rate	5.5%
Tax Rate	38.0%	%/yr, Matches PSFM	38.0%
Escalation Rate	3.0%	%/yr	3.0%
General and Administrative (G&A) Factor	20%	Assessed on all labor costs	
Site Characterization Failure Contingency	0%	Assessed to account for charac sites not bei	
Process Contingency Factor	20%	Assessed on all monitoring costs	
Project Contingency Factor	15%	Assessed on capital costs	
Lease bonus	$ 50.00	$/acre	
Injection (for lease holders)	$ 0.25	$/tonne	
Long-term Stewardship Trust Fund (State)	$ 0.07	$/tonne	
Operational Oversight Fund (State)	$ 0.01	$/tonne	

There are several fees associated with CO_2 storage operations that are also posted here:

Lease bonus – So many dollars per acre, here a value of $50 is used. In oil and gas leasing, this is the amount paid to secure a lease from the landowner who has the mineral rights. In the model, securing a lease also secures pore space rights and right of access to the surface to drill wells and install associated equipment and facilities.

Injection (fee to leaseholders) – A fee paid to lessor for each tonne of captured CO_2 injected, analogous to royalty payment for oil and gas.

Long-term Stewardship Trust Fund – A fee paid in per tonne of captured CO_2 injected. Several states have enacted legislation establishing a Long-term Stewardship Trust Fund, each having a different fee, some with ceilings.

Operational Oversight Fund – Some state are considering charging a fee per tonne of captured CO_2 injected to cover their regulatory oversight costs.

4.1.8 Financial Responsibility Selection (Exhibit 17)

The model allows the modeler to meet financial responsibility (FR) requirements by selecting one or a combination of the six financial instruments recognized by the EPA. Also available to meet financial responsibility requirements in this model is a modified trust fund or escrow account not yet recognized by EPA. In this model, these financial instruments methods will cover three components of financial responsibility: corrective action, injection well plugging, and PISC and site closure. Emergency and remedial response (ERR) is always covered by insurance in this model. Only trust funds (or escrow accounts), modified trust funds (or modified escrow accounts), and self-insurance can be used for PISC. For corrective action and injection well plugging, a letter-of-credit, surety bond, or insurance can be selected to meet financial responsibility. To select a financial instrument for each of the three components, click on the orange-colored box that reads 'Modified Trust Fund' within the 'Inputs and Selected Outputs Related to Financial Responsibility' table (Exhibit 17). A drop-down box arrow appears and once clicked will reveal a list of financial responsibility options. The adjacent boxed area provides a description of the financial instrument selected, which is also provided below: Escrow account is not listed here. In the model, accounting for the use of an escrow account is identical to that for a trust fund. The fundamental difference is the rate of return for each with the trust fund earning a higher return.

Trust fund: If using a trust fund, owners or operators are required to set aside funds with a third party trustee sufficient to cover estimated costs. During the financial responsibility demonstration, the owner or operator may be required to deposit the required amount of money into the trust prior to the start of injection or during the 'pay-in period,' if authorized by the director. This option is identical to a modified trust fund with one revision; rather than funding the reserve over the project's operations, the reserve must be funded prior to operations. In order to demonstrate financial responsibility upon application for a Class VI permit, the 3-year pay-in period for the Trust Fund can be adjusted to occur during site characterization or begin (Start Year) during site characterization and end (End Year) during permitting (Exhibit 18). In their guidance, EPA has also mentioned making an initial payment into the trust fund (or escrow account) prior to drilling the injection well(s). For a typical modeled project a trust fund is set up to be funded in years 2-4 of the project prior to permitting to meet the 'demonstration' requirement; or funded in years 6-8 if initial payment is made prior to drilling the injection well. The trust fund grows at a rate defined by the user.

Escrow account: This option is mechanically the same as a trust fund in the model. The EPA allows for a funded escrow account as an acceptable mechanism for demonstrating financial responsibility. As with a trust fund, the model assumes these funds are properly managed and the money is available when needed. An escrow account as a lower rate of return than a trust fund since it is assumed that the escrow account is passively managed while the trust fund has active management. Funds in an escrow account are considered more liquid than those in a trust fund.

Modified trust fund: Owners or operators may deposit money into a modified trust fund to cover financial responsibility requirements. This account must segregate funds sufficient to cover estimated costs for financial responsibility from other accounts and uses. Under this scenario, the project funds a reserve account that will cover all financial responsibility costs. This account is funded over the operating period of the project to minimize the amount of financing required to fully fund it. All financial responsibility costs are to be paid out of this account when they are due. If there is any money left in the account after all financial responsibility obligations have been met, this money will be returned to the owners. The modified trust fund is scheduled to fund over years 7-36, concurrently with injection and revenue generation. The fund grows at a rate defined by the user.

Letter of credit: A letter of credit is a credit document, issued by a financial institution, guaranteeing that a specific amount of money will be available to a designated party under certain conditions. In case of operator default, letters of credit fund standby trust funds in an amount sufficient to cover estimated costs. This option is identical to self-insurance with one addition; the project pays a letter of credit fee to guarantee access to enough capital to cover all financial responsibility costs of the project. To establish this letter of credit fee, it is necessary to calculate the total financial responsibility burden in the given year and assume that a percentage must be paid from the project (starting assumption is 0.15 percent). The line of credit is available beginning in year 7 and ending in year 86, when the site is closed at the end of Post-Injection and Site Care. This notion mirrors the period where all financial responsibility costs are incurred.

Insurance premiums: The owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party to decrease the possibility of failure (i.e., non-captive insurer). This option is identical to self-insurance with one addition; the project pays an insurance premium to guarantee that all of the financial responsibility costs will be met in the year they are due. To establish this premium, it is necessary to calculate the full financial responsibility burden in the given year and assume that a percentage of it must be paid from the project (starting assumption is one percent, which is the annual premium or the estimated value of the financial responsibility liability). Payments begin in year 7 and end in year 86, when the site is closed at the end of Post-Injection and Site Care. This notion mirrors the period where all financial responsibility costs are incurred.

Self-Insurance (i.e., financial test and corporate guarantee): Owners or operators may self-insure through a financial test, provided that certain conditions are met. The owner or operator needs to pass a financial test to demonstrate profitability with a margin sufficient to cover contingencies, unknown obligations, and stability. If the owner or operator meets corporate financial test criteria the owner or operator can guarantee its ability to satisfy financial obligations based solely on the strength of the company's financial condition. An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that the owner or operator's corporate parent meets the financial test requirements on its behalf. This demonstration is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator. Under self-insurance, the owner pays all bills when they come due. Therefore, corrective action is paid at the time it is performed; injection well plugging costs is paid at the time they are incurred; PISC costs are paid in each PISC year during the period; and the owner promises to pay any emergency and remedial response in the event of a leak.

Surety Bond: Owners or operators may use a payment surety bond or a performance surety bond to guarantee that financial responsibility will be fulfilled. In case of operator default, a payment surety bond funds a standby trust fund in the amount equal to the face value of the bond and sufficient enough to cover estimated costs. A performance surety bond guarantees performance of the specific activity or payment of an amount equivalent to the estimated costs into a standby trust fund. This notion is modeled identically to self-insurance.

Exhibit 17 Financial responsibility selection

Inputs and Selected Outputs Related to Financial Responsibility

Corrective Action Funding: Select a Method to Use for Financial Responsibility

Modified Trust Fund	Owners or operators may deposit money to an Modified Trust Account to cover financial responsibility requirements. This account must segregate funds sufficient to cover estimated costs for GS financial responsibility from other accounts and uses. Under this Scenario the Project funds a reserve account that will cover all Financial Responsibility Costs. This Account is funded over the operating period of the project to minimize the amount of financing required to fully fund it. All Financial Responsibility Costs are to be paid out of this account when they are due. If there is any money left in the account after all Financial Responsibility obligations have been met this money will be returned to the Owners.
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Injection Well Plugging Funding: Select a Method to Use for Financial Responsibility

Modified Trust Fund	Owners or operators may deposit money to an Modified Trust Account to cover financial responsibility requirements. This account must segregate funds sufficient to cover estimated costs for GS financial responsibility from other accounts and uses. Under this Scenario the Project funds a reserve account that will cover all Financial Responsibility Costs. This Account is funded over the operating period of the project to minimize the amount of financing required to fully fund it. All Financial Responsibility Costs are to be paid out of this account when they are due. If there is any money left in the account after all Financial Responsibility obligations have been met this money will be returned to the Owners.

PISC Funding: Select a Method to Use for Financial Responsibility

Modified Trust Fund	Owners or operators may deposit money to an Modified Trust Account to cover financial responsibility requirements. This account must segregate funds sufficient to cover estimated costs for GS financial responsibility from other accounts and uses. Under this Scenario the Project funds a reserve account that will cover all Financial Responsibility Costs. This Account is funded over the operating period of the project to minimize the amount of financing required to fully fund it. All Financial Responsibility Costs are to be paid out of this account when they are due. If there is any money left in the account after all Financial Responsibility obligations have been met this money will be returned to the Owners.

Other instrument(s) satisfactory to the director: In addition to these instruments, EPA anticipates that new instruments that may be tailored to meet geologic sequestration needs may emerge and may be determined appropriate for use by the director for the purpose of financial responsibility demonstrations.

ERR is Another Element of Financial Responsibility: In the model, ERR is addressed through an insurance policy and the premium for the policy is paid through a fee per tonne ($0.75) of CO_2 injected beginning in the first year of injection and ending in the last year of injection. The modeler can adjust this fee. Insurance is the only financial instrument provided in the model to address ERR, so ERR insurance is always active in the model regardless of the financial instruments selected to address other aspects of FR. Although the ERR insurance premium is paid during operations, the insurance policy is assumed to cover ERR incidents starting the first day of operations and lasting through the end of PISC (i.e., until formal closure of the Class VI injection well permit is granted by the lead regulatory agency).

Specifying Parameters for Financial Responsibility Instruments: The table shown in Exhibit 18 provides the user with the ability to specify inputs to parameters for various financial responsibility instruments, including:

1. The start and end years of the trust fund's funding schedule.
2. The letter of credit fee as a percent of the total letter of credit amount.
3. The general insurance fee.
4. The premium for ERR insurance.
5. Parameters for the trust fund and modified trust fund.

The fees in items 2 and 3 are assessed on an annual basis and are calculated as a percent of the total value covered by the instrument. For example, if letter of credit is used for the corrective action aspect of financial responsibility, the total value of the letter of credit would equal the nominal costs of corrective action. The annual fee would be a percentage of the total value of the letter of credit.

As discussed above, the premium for ERR insurance (item 4) is assumed to be a fee levied on each tonne of CO_2 injected. The fee is in 2008 dollars (the base year) and escalates each year at the general rate of escalation input by the user. The ERR insurance premium is assumed to be paid during operations (i.e., when CO_2 is injected), but coverage begins the first day of operations and extends until the site is closed at the end of PISC.

The trust fund and modified trust fund are designed so that the user deposits specified amounts of money each year into the trust and this money grows according to an interest rate specified by the user. For the trust fund, deposits are made in three consecutive years early in the project. For the modified trust fund, deposits are made each year during injection operations. Item 5 refers to the parameters used to calculate the money needed to be deposited each year into the trust and how this money grows. The deposits made each year grow at an interest rate specified by the user. The amount of each deposit can either be a constant nominal value in each year (i.e., the same number in nominal dollars each year or, equivalently, a decreasing value in real dollars) or a constant real value in each year that increases each year in nominal dollars. The rate at which the deposits escalate is given by the "Deposit Escalation Rate" specified by the user. If the user desires deposits in constant nominal dollars then the "Deposit Escalation Rate" should be input as zero, otherwise the "Deposit Escalation Rate" should be input as the general escalation rate used in the model. The amount of money to be deposited each year is calculated by the model using the "Assumed Interest Rate" which is specified by the user. However, the deposits actually grow at the "Actual Interest Rate" specified by the user. The "Assumed Interest Rate" must be less than or equal to the "Actual Interest Rate". If the "Assumed Interest Rate" is less than the "Actual Interest Rate" then there are excess funds in the trust at site closure and these excess funds are returned to the owners. By specifying an "Assumed Interest Rate" that is less than the "Actual Interest Rate", the trust fund or modified trust fund will be over funded, ensuring that more than enough money will be available for the activities covered by financial responsibility. The "Assumed Interest Rate" and "Actual Interest Rate" are net interest rates after taxes and administrative fees have been deducted. In other words, any taxes on earnings from the trust are assumed to be paid from the trust funds and administrative fees for operating the trust are also assumed to be paid from the trust. The taxes paid and administrative fees are not explicitly calculated but need to be deducted when determining the "Assumed Interest Rate" and "Actual Interest Rate". Most users are likely to desire constant deposit amounts in nominal dollars, so the "Deposit Escalation Rate" should be set to zero. Most users will probably not want to overfund the trust, so the "Assumed Interest Rate" should be set equal to the "Actual Interest Rate."

Exhibit 18 Financial responsibility details

Trust Fund and Modified Trust Fund					
Trust Fund (before operations):		Start Year	6	End Year	8
Modified Trust Fund (during operations):		Start Year	7	End Year	36
Letter of Credit					
0.15%	1/year	Start Year	7	End Year	86
Insurance Premiums					
General (All Coverage BUT Emergency and Remedial Response)					
1%	1/year	Start Year	7	End Year	86
ERR (Emergency and Remedial Response Coverage)					
$ 0.750	$/tonne/yr	Start Year	7	End Year	36
	Assumed Interest Rate	Actual Interest Rate	Deposit Escal. Rate		
Trust Fund Rates:	5.0%	5.0%	0.0%		
Modified TF Rates:	5.0%	5.0%	0.0%		
Assumed interest rate is used to calculate deposits to trust funds. It should be less than or equal to the actual interest rate.					
Actual interest rate is the rate actually earned by the money in the trust funds. Any excess is returned to the owner.					
Deposit escalation rate is the rate at which deposits escalate. If zero, deposits are constant in nominal dollars over time.					

4.2 Activity Cost Module

Tables 1.1 through 1.5 provide the modeler critical information of the 'Activity_Inputs' worksheet. These global parameters, shown in Exhibit 19, are used in calculating and posting cost data to the Back-End Cost Items worksheet. Below is a description of each table.

1.1 Labor Rates

There are four categories for labor rates: geologist, engineer, landman, and field.

Purpose: These rates get carried through to any activities that require labor hours. They are applied to each activity based on the type of labor selected by the modeler.

Options: If the modeler has better data for hourly rates, the new data can be applied.

1.2 Total Tonnes Injected

Purpose: The tonnes injected affect all costs dependent on the tonnes injected per year, as well as any costs dependent on the total tonnes injected. This item also determines which of the formations are eliminated due to lack of capacity, which is a crucial underlying assumption of the model that affects all results.

Options: Changing the management decision for tonnes injected is done in the 'Project_Management sheet.

1.3 Conversions

Purpose: Shows a standard conversion used in the model. Although it is a fact and not a decision, it is posted to call out the fact that it is used.

Options: The modeler will not need to make a change to this conversion unless units change elsewhere in the model.

1.4 Default Stage Timeline

Purpose: For each project stage modeled, this table shows the length of each project stage in years, the beginning and ending project year, and the beginning and ending calendar year for each project stage. Therefore, these years play a major role in the timing of costs overall.

Options: By changing the duration of each stage in the 'Project_Management' sheet, the default timing information will change here.

1.5 Well-Drilling Inputs

Purpose: This table shows well-drilling inputs that are entered on the 'Project_Management' sheet. Data posted is information for the modeler. No data modification is possible.

Options: The well-drilling inputs are entered on the 'Project_Management' worksheet.

Pipeline distance is entered in the Surface Equipment Input portion on the 'Project_Management' worksheet. See section 4.1.4.

Escalation value is imported from the 'Project_Management' worksheet.

Exhibit 19 Global parameters

Parameters Consistent Across all Activities

1.1 Labor Rates

Labor Rates	Amount	Value Used (Accounts for G&A)	Unit
Geologist	107.23	128.68	$/Hour
Engineer	110.62	132.74	$/Hour
Landman	75.00	90.00	$/Hour
Field	50.00	60.00	$/Hour

1.2 Total Tonnes Injected

Tonnes Injected	96,000,000.0
Tonnes per Day	8,484.3

1.3 Conversions

acres/ sq.mile	640

1.4 Default Stage Timeline

Default Stage Years: Enter Zero in any cost's Begin Year or End Year to revert to the corresponding stage's default years.

	Duration (Years)
Regional Evaluation	1
Site Characterizaion	3
Permitting	2
Operations	30
PISC and Site Closure	50

	Begin Year	End Year	Calendar Years Chosen
Regional Evaluation	1	1	2012 - 2012
Site Characterizaion	2	4	2013 - 2015
Permitting	5	6	2016 - 2017
Operations	7	36	2018 - 2047
PISC and Site Closure	37	86	2048 - 2097

The default years are currently being used for 93.8% input years.

Project Begins in Year:	2012

1. 5 Well-Drilling Inputs	Value	Units
Number of Strat Test Wells	5	wells
Number of Injection Wells	53	wells
Number of Water Production	4	wells
Number of Water Disposal	4	wells
Monitoring Well Density		
Monitoring Wells In Reservoir	4	mi2/well
Monitoring Wells Above Seal	2	mi2/well
Monitoring Wells that are Dual Completed	4	mi2/well
Monitoring Wells Groundwater	3	Wells/Injection Well
Monitoring Wells Vadose Zone	3	Wells/Injection Well
Percentage Wells In Reservoir that are Dual Completed	100%	% Dual Comp.

	Value	Units
Pipeline Distance		
Escalation	3%	103%

Activity Specific Parameters

Tables 2.1-2.15, located in the 'Activity_Inputs' tab are specific activities that get performed one or more times over a specific stage in the project. The stage is labeled in blue on the left side of most cells in the table, as shown in Exhibit 20. The activity's timing and a user's ability to edit them is a critical benefit of the model. Each one of these activities is assigned a beginning year and an end year within its project stage. The user can use the model's default values or override them by inputting their own values in the orange cells of Columns U and V marked 'Begin Year' and 'End Year.' These cells bound the timeframe over which the specific activity can be performed. In order to determine frequency, the user can adjust the value in cell U16 (labeled 'Periodic'). A value of '1' means this activity will be performed every year over its eligible time frame, while a value of '5' means the activity will happen every five years over this period. The user can select any level of frequency desired. If the cost is desired to be a one-time cost, the user should select identical beginning and end years and input a '1' into the 'Periodic' cell. Below is a description of each table on within their appropriate stage for this portion of the Activity Cost Module.

Exhibit 20 Activity specific parameters

Regional evaluation for site selection

2.1 Purchase/ Acquire/ Analysis (PAA):

	Cost	Unit	Geologist	Unit	Engineer	Unit	Landman	Unit	Field	Unit
Geologic data on areal extent, thickness,	1,500	$	24	Hours		Hours				
Geophysical seismic data	1,500	$		Hours						
Seismic (earthquake) history data	1,500	$	60	Hours						
Geochemical data	1,500	$		Hours						
Geomechanical data	1,500	$	120	Hours		Hours				
Land data	1,500	$					500	Hour		
Software	1,500	$								
Other 1										
Other 2										
Other 3										
Other 4										
Other 5										

User Input Selection

Begin Yea	End Year
0	0

Years that will be used

Begin Yea	End Year
1	1

Periodic
1

Regional Geologic Evaluation

2.1 Purchase/Acquire/Analysis (PAA)

This table contains unit costs and labor hours associated with acquiring and analyzing data and software to conduct a regional geologic evaluation for the purpose of selection a site for site characterization and eventually permitting.

Purpose: Post initial costs for the project. None of the work here is required by Class VI permit regulations but it is critical to the success of the project.

Options: The modeler may want to adjust the number of hours estimated for labor for these activities to the extent they believe the activity is more or less labor intensive than the baseline.

Site Characterization

2.2 PAA (data/software not acquired earlier)

This table contains unit costs and labor hours associated with acquiring and analyzing data and software for site characterization, which has not been previously acquired.

Purpose: Similar to Table 2.1, these costs address regulatory needs. Gathering this data and providing it in the numerous plans required for a Class VI permit application is mentioned in the regulations.

Options: The modeler may want to adjust the number of hours estimated for labor of these activities.

2.3 Prepare

Purpose: All items are required in the regulations. Post labor hours are associated with this work. Clicking on each item's cell provides a fuller title of each item that has to be prepared.

Options: The modeler may want to adjust the number of hours estimated for labor for these activities.

2.4 Modeling (Labor Hours)

Purpose: Post labor hours associated with CO_2 plume migration modeling; 100 and 10,000 year modeling of CO_2 plume in reservoir. Modeling associated with tying well control to seismic data is also added. The reservoir modeling is included here, and any improvements in modeling time or methods would be reflected in this table.

Options: The modeler may want to change which type of modeling is done or how many hours are spent modeling. Changes will be made within this table.

2.5 Corrective Action Planning (Labor Hours)

Purpose: Any labor hours used for corrective action planning are listed in this table.

Options: The modeler can use this table to change labor hours required or add a unit cost associated with corrective action planning.

2.6 Front-end Engineering and Design (Labor Hours)

Purpose: This table contains front-end engineering and design labor hours for three areas: injection wells, monitoring wells, and surface facilities/intra-field pipelines.

Options: The modeler may choose to change the cost per well, field-wide cost, or the labor hours for each of these items.

2.7 Preparation of Plans for Class VI Permit (Labor Hours)

Purpose: This table contains field-wide cost and labor hours for all preparation of the five plans required for submittal on Class VI permit application: AoR and corrective action, testing; MVA; injection well plugging; PISC and Site Closure; and Emergency and Remedial Response. Also prepared and secured during site characterization are the instruments that will satisfy financial responsibility.

Options: The modeler may choose to change the field-wide cost or the labor hours for any of the costs associated with Class VI.

2.8 Land Leasing (Labor Hours)

Purpose: This table covers labor and costs associated with securing pore space rights: landman labor hours for securing leases, value of bonuses ($/acre) paid for leases, and cost for public outreach program. The lease bonus value posted here is from the Inputs Related to Financial Module table (Exhibit 16) in the Project Management Module.

Options: The modeler may change the cost per acre for these items if the modeler has better information or wants to consider analysis with specific data.

Permitting

2.9 Permits (Labor Hours)

Purpose: This table includes costs for various permits that may be required for well drilling or other activity depending on Federal/State regulations. Both the cost per well and the labor hours associated with obtaining these permits can be posted in this table. These costs are important as permits are a crucial part of complying with regulations.
Options: The modeler may change the cost per well or the labor hours required for a given permit. This would be done as an update of information or to analyze the impact of a change in permit costs.

2.10 Injection Well Drilling(Labor Hours)

Purpose: Class VI permit approval is a two-stage process. Approval to drill the injection wells is granted. These wells are drilled and all of the data gathered from these wells, wireline logging, cores, vertical seismic profile (VSP), etc. must be incorporated with the five plans submitted for permit application. The cost of updating these plans is posted in this table including a field-wide unit cost as well as labor costs. The per-well costs, such as drilling and completing the injection wells, are in Tables 4.1-4.13.
Options: The modeler may choose to change the field-wide costs or labor hours associated with injection well planning.

2.11 Subpart RR (Labor Hours) (Subpart UU for ER Projects)

Purpose: This table consists of one cost item, which covers the field-wide cost and labor hours required for the Monitoring, Verification, and Reporting plan required to comply with Subpart RR.
Options: The modeler may use this table to adjust the reporting cost to comply with different regulations.

Operations

2.12 Gathering Field Data

Purpose: This table covers the labor costs for gathering data, both for subpart RR reporting and for other monitoring activities.
Options: The modeler can adjust the frequency of reporting and the number of labor hours required for these activities.

2.13 Corrective Action

Purpose: This table contains the costs for corrective action based on deep wells and water wells. Presently, only deep wells are modeled. Cost items posted include cleaning out and plugging the well. The modeler enters the density of occurrence of old wells requiring corrective action in cells T147 and T148. Presently, a Corrective Action well occurs every 4 square miles or $0.25/mi^2$. Total number of corrective action wells depends on the areal extent of the plume.
Options: The modeler can change the assumed number of wells for corrective action and the assumed cost for clean out, log, and re-plugging.

Parameters Used in Activities across Multiple Stages

Tables 3.x are for activities that can be performed across more than one of the project stages: site characterization, permitting, operations, and PISC. For example, "Frequency (yrs) for Application of Technology" in Table 3.6 Aerial/Satellite Survey provides for these technologies to be applied in one or all four project stages (Exhibit 21). The user inputs the desired frequency of 1, 5, or 10 years. The activity will be performed every year, 5 years, or 10 years during the default time frame posted in the gray cells at the right end of the table. The default time period is pulled in from the Project Management Module (see Exhibit 9). The beginning and end years can be selected by the user, the orange cells under "User Input Selection". This option allows the user to pick specific years within a project stage if needed. Otherwise, the default assumption will include the full time span of the project stage in which the activity is performed.

As posted in Exhibit 21, an aerial survey and air-magnetic survey are done during site characterization, annually over project years 2 and 4. No other technology is applied. See the discussion on Exhibit 5 for additional information regarding timing of use of technology.

Exhibit 21 Scheduling work in different project stages

3.6 Aerial/Satellite Survey

	Technology Cost			Frequency (yrs) for Application of Technology			
	Mobilization Cost	Cost per mi2	% Inc. for Data Pro.	Site Characterization	Permitting	Operations	PISC and Site Closure
	$	$/mi2	%				
Aerial survey (Land, land use, structures, etc.)	3,100.00	415.00	41.50	1			
Air-magnetic survey for old wells	5,200.00	11,160.00	1,116.00	1			
Synthetic Aperture Radar (SAR & InSAR)	5,200.00	11,160.00	1,116.00				
Color Infrared (CIR) Transparency Films	5,000.00	6,250.00	625.00				
Thermal Hyperspectral Imaging			0.00				
Ecosystem Stress Monitoring			0.00				
% over 3D marg	% of mi2	0%					

User Input Selection		Years that will be used *		
Begin Year	End Year	Begin Year	End Year	
0	0	2	4	Site Ch.
0	0	5	6	Permit.
0	0	7	36	Ops.
0	0	37	86	PISC

3.1 Fees per tonne CO_2 (Other Expenses)

Purpose: This table contains per tonne fees paid during operations: an injection fee to lease holders, a long-term stewardship trust fund fee for the state, and an operational oversight fund fee for the state. Only a few states have established a long-term stewardship trust fund and/or other fees to support their efforts to regulate CO_2 sequestration. These values are pulled in from the Project Management Module. See Inputs Related to Financial Module (Exhibit 16)

Options: For specific analysis, the modeler can update these values in the Project Management Module if better information is available or to see how a change in fees would impact a project.

3.2 Fees, One-Time (Other Expenses)

Purpose: This table contains fees that are paid one-time in compensation due to well drilling or establishing a surface monitoring site. Costs posted here for public outreach are a continuation of public outreach efforts conducted during leasing (Table 2.8 in 'Activity_Inputs' sheet).

Options: The modeler can update these values if better information is available, for specific analysis, or to see how a change in fees would impact a project.

3.3 Periodic Reports

Purpose: This table includes labor hours related to record keeping, modeling field data, and report writing for periodic reports. These reports include semi-annual/annual or other periodic reports required by Class VI or subpart RR regulations. At a minimum of every five years, AoR review is required. Any change in this plan report reflecting updated data interpretation must be reflected on all other plans tied to the permit, including financial responsibility.

Options: The modeler may choose to use different values for labor hours if better data indicates a change. The modeler can change the hours for recordkeeping, modeling field data for reports, or report preparation.

3.4 Fluid Samples

Purpose: The technology cost and frequency of collecting fluid samples in various types of wells is posted in this table. Under the technology cost heading in the table, the cost to collect these samples depends on the number of sampling occurrences per year (12-if sampled monthly, 4-if sampled every three months) and the number of samples taken during each occurrence of sampling. The cost to collect samples per occurrence of sampling includes labor, while the cost to analyze each sample is posted separately. Frequency of sampling allows the modeler to select in which stage of the project samples will be collected. Entering '1' for operations and PISC means sampling will occur annually.

Options: The modeler may decide to use these cells to look at the impact of changing the number of samples taken or how frequently they are taken.

3.5 Gas Samples

Purpose: This table lists costs for collecting gas samples from the Vadose Zone well or from Flux Accumulation Chambers. The cost for Vadose Zone well samples depends on the number of sampling occurrences per year (12- if sampled monthly, 4- if sampled every three months) and the number of samples taken during each occurrence of sampling. The cost to collect samples per occurrence of sampling includes labor, while the cost to analyze each sample is posted separately. Cost for the Flux Accumulation Chamber is per survey and the number of sampling points in a survey.

Options: The modeler may decide to use these cells to look at the impact of changing the number of samples taken or how frequently they are taken. Also, the modeler can change the cost for analyzing samples if better data becomes available.

3.6 Aerial/Satellite Survey

Purpose: This table lists aerial survey, air-magnetic survey for old wells, synthetic aperture radar, color infrared transparency films, thermal hyperspectral imaging, and ecosystem stress monitoring technology. Costs posted include mobilization cost, cost per square mile that the survey covers, and cost for data processing.

Options: The modeler may choose to change the values posted to reflect change in coverage or unit costs. Additionally, if these costs are to be applied over an area larger than the AoR for 3-D seismic, the modeler can add a percentage margin to extend the survey.

The next tables require information on plume growth to calculate full cost of a seismic run.

Plume and Well Schedule:

This worksheet lists time-dependent geologic factors, such as well counts and plume growth, in a timeline. In this sheet, the modeler can find all year-dependent factors, including plume area, area of review, and well counts. Additionally, the inputs and assumptions relevant to these values are posted on the sheet for reference. This worksheet shows how many wells are added in a given year. It also shows the Plume area in a given year that would need to be covered if a seismic shoot were required by the manager. There are three areas that are relevant to various costs: the plume uncertainty area, the 3D seismic area, and the pressure front. Most costs depend on the plume uncertainty area. The 3D seismic area is used for the seismic costs, and the pressure front is used only for a small number of wells that are drilled between the plume uncertainty boundary and the pressure front.

Exhibit 22 Plume growth

			Column Headers:		Calendar Year		Project Year	
	Calendar Yr.		2011	2012	2013	2014	2015	2016
	Project Yr.		1	2	3	4	5	6
CO2 Plume Area and Other Area Calcs.	Units	Max. or Sum						
Area of CO2 plume	mi2	10.3	0.0	0.0	0.0	0.0	0.0	0.0
Area of CO2 plume including uncertainty	mi2	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Area of CO2 pressure front	mi2	179.9	179.9	179.9	179.9	179.9	179.9	179.9
Effective area of CO2 plume including uncertainty for 3D seismic monitoring	mi2	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Area used for 3D seismic surveys with minimum starting area	mi2	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Effective area of CO2 plume including uncertainty for 2D seismic monitoring	mi2	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Length used for 2D seismic surveys with minimum starting length	miles	6.7	6.7	6.7	6.7	6.7	6.7	6.7

3.7 Surface Seismic 3-D

Purpose: This table displays the costs for acquiring 3-D seismic data. The input cells for this table are on the 'Project_Management' sheet. The total cost of 3-D seismic is based on the cost per square mile over which 3-D data is acquired plus a processing fee expressed as a percentage of the per square mile acquisition cost. Areal extent for any seismic survey depends on the areal extent of the CO_2 plume, which is calculated in the Geologic Module and is represented as a circle. During site characterization, the final post operations areal extent of the plume is unknown and a margin is added, called the AoR margin. This AoR margin is expressed as a percentage of the plume area. Seismic coverage, 2-D or 3-D, begins beyond or outside the margin of the subsurface object to be imaged. This seismic margin is calculated at a 45-degree angle from the edge of the subsurface object (plume) to be imaged.

Options: The modeler can make any changes to 3-D seismic inputs on the 'Project_Management' Module (see Exhibit 15). The modeler may choose to change any of the costs due to better available data or specific analysis. If AoR margin is set to zero, the plume size image is the default calculation performed by the Geologic Module. This calculation may be done during operations assuming that the edge of the plume is known. Several technologies, including 3-D seismic, can be used to indirectly measure the CO_2 plume in the reservoir. Other technologies can be modeled for this purpose in lieu of 3-D seismic or in conjunction with this or other seismic technology.

3.8 Surface Seismic 2-D

Purpose: This table displays the costs for acquiring 2-D seismic data. The total cost of 2-D seismic is based on the cost per linear mile plus a processing fee expressed as a percentage of the per linear mile acquisition cost. The AoR and seismic margin applied are same as 3-D seismic except that linear mile is the parameter costed instead of square miles.

Options: The modeler may choose to change any of these costs or to turn them on or off to reflect various monitoring scenarios. The baseline uses 2-D seismic for site characterization, but many alternatives have been considered by various projects, so the modeler may want to use 2-D during the entire project or not use it at all.

3.9 Wellbore Seismic (For In Reservoir and Above Seal Wells)

Purpose: This table covers seismic data acquisition from the wellbore for in reservoir and above seal wells. Crosswell seismic and microseismic are selected in this table. Microseismic technology is a known quantity. Crosswell seismic requires the use of two wells, and it is still in the testing stage. Use of VSP technology is selected in the Well Drilling Costs table.

Options: The modeler may choose to change any of these costs due to better available data or specific analysis.

3.10 Electrical

Purpose: The selection of several different electrical technologies is provided in this table. The costs for these technologies are not currently known, but several are being tested by various regional partnerships. Cost, when posted, is calculated using a cost per station and number of stations. Additionally, there is an option to add a percentage of the cost for data processing. Some of these details may change upon learning more details of the electrical technologies listed in this table.

Options: The modeler may choose to change any of these costs or to select 'electrical' as a replacement for other monitoring techniques.

3.11 Other Geophysical

Purpose: This table contains other geophysical technology options, including gravity survey and tiltmeter. The costs are calculated using the number of stations and cost per station. Additionally, there is an option to add a percentage of the cost for data processing.

Options: The modeler may choose to change any of these costs or to select other geophysical methods for analysis that makes use of these particular technologies.

3.12 Atmospheric

Purpose: This table covers cost items for atmospheric monitoring, including CO_2 detectors, eddy covariance, advanced leak detection system, and laser systems and light detection and ranging (LIDAR). These costs are calculated using a mobilization cost, cost per square mile, equipment unit cost, and a percentage of the other costs to be applied for data processing.

Options: The modeler may choose to change any of these costs or turn them on or off. The modeler should note that the eddy covariance costs depend on the number of sites, which is defined in Table 2.16 Other Costs.

3.13 Injection Well Monitoring

Purpose: This table contains the pressure falloff test and the corrosion tests for injection well monitoring. Technology cost, labor cost and frequency of testing is posted in this table. Posting technology cost for these tests can be done one of two ways. Corrosion testing involves samples of the casing. Costs depend on the number of sampling occurrences per year, and the number of samples taken during each occurrence of sampling. There are costs to collect and analyze each sample. The pressure falloff test is a single event with a single test cost. If necessary, labor hours can be included in this table for both. Entering '5' under Operations for the pressure falloff test means that this test will be run every five years on all of the injection wells. Entering '1' under Operations for the corrosion tests means that this test will be annual.

Options: The modeler may choose to change any of these costs due to better available data or specific analysis. Also, the modeler may use either of the two methods for including costs.

3.14 Data Analysis and Modeling

Purpose: This table covers costs related to reservoir modeling, data analysis, and laboratory testing during site characterization. The reservoir modeling and data analysis include an annual component and a periodic cost component.

Options: The modeler may choose to change any of these costs due to better available data or specific analysis. Also, the modeler may increase or decrease the frequency of the periodic costs.

Well Drilling Costs

Costs to drill, complete, and plug and abandon several different types of wells are selected or posted in this table within the 'Activity_Inputs' worksheet. Strat-wells are only drilled during site characterization. Currently, injection wells are only drilled during permitting. Replacement/new injection wells drilled during operation may be provided in a future version of the model. All monitoring wells are drilled during operations. Not all in-reservoir and above-seal monitoring wells are drilled at the beginning of operations. An equal number of in-reservoir and above-seal monitoring wells are drilled every five years with the initial group drilled at the beginning of operations. Well spacing for in-reservoir and above-seal monitoring wells is in square miles. Presently, well spacing for in-reservoir and above-seal monitoring wells are 4 square miles and 2 square miles, respectively. Dual completion of the in-reservoir monitoring well and above-seal zone are presently done in the model. Groundwater and Vadose Zone monitoring wells are tied to the injection well. Presently, there is one monitoring wells drilled for each injection well. Water production and water disposal wells are also costed here. Modeling parameters regarding water production-treatment-disposal are explained later. Monitoring well spacing, dual completions and the number of ground water and vadose zone wells are management decisions posted in the Project Management Module.

The Well-Drilling Costs include costs that occur when a well is drilled, throughout the life of the well and when the well is plugged and abandoned. These costs are posted in Tables 4.1 through 4.90. Costs in each table are summed and posted to the Back-End cost sheet to be posted in the year that each cost occurs. Some cells blanked out with a dark gray color which indicates that the cost is not relevant for the given well type. Tables 4.1 through 4.90 are grouped to accommodate timing of costs. Five tables providing an opportunity to adjust the project year when well costs occur. These tables define time or time span when a well is drilled and completed, when O&M costs are applied, when tests are conducted in the well during its life and when the well is plugged and abandoned. Values representing the project year posted in the light gray cells (Exhibit 23) are pulled from the Project Management module. Posting a value in the orange cell will override the values in the gray cells. This is the first of five tables where the modeler can set the project year in which costs occur.

Well Properties is the top table for Well-Drilling Costs. Here, the depth for each type of well drilled along with casing and tubing diameter used is posted. Further beneath each type of well drilled in numerous tables are posted additional parameters for each well related to calculating costs.

Exhibit 23 Well-Drilling Costs

Well-Drilling Costs

	Cost Parameter	Strat Test		Injection		Conversion of Strat Test to Injection
Well properties	Depth (ft)	5,050.00		4,550.00		4,550.00
	Diameter casing (in)	7.50		7.50		7.50
	Diameter tubing (in)	4.00		4.00		4.00

Timing	**Time frame for application of costs.**	Strat Test	ON/OFF (x=on; blank=off)	Injection	ON/OFF (x=on; blank=off)	Conversion of Strat Test to Injection
Enter zero to use default values. For a One-Time cost set the Begin Year=End Year.	**Begin Year** - user input year	0		0		0
	End Year - user input year	0		0		0
	Begin Year - year that will be used	2		6		6
	End Year - year that will be used	4		6		6
	Periodic	1		1		1

Notes: These timing data are used for Sections 4.1 to 4.10.

	Cost Parameter	Strat Test		Injection		Conversion of Strat Test to Injection
4.1 Permits	Well (Drilling) permit ($/well)	100	x	100	x	0
	Water Discharge ($/well)					
	Air Emissions ($/well)	0		0		0
for Back-End_Cost Items sheet	Total for above three rows ($/well)	100		100		0

Notes: Permit costs are incurred in the year the well is drilled except as noted below for conversion of strat wells.
For strat wells converted to injection wells or deep monitoring wells, any listed permit costs are incurred in the year the conversion occurs.
Data in rows with label "for Back-End Cost Item sheet" are used in Back-End Cost Items sheet.

4.1 Permits

Purpose: This table includes costs for well drilling permits (other than Class VI), water discharge permits, and air emissions permits.

Options: The modeler can choose to turn on or off (x = on, blank = off) permitting costs. Also, the modeler may decide to change the cost data to better available data or to specific analysis of the cost's impact. The on-off feature describe here is present in all well cost tables.

4.2 Drilling Costs

Purpose: This table posts the costs for drilling wells. The costs are calculated in the worksheet 'Drilling Costs' uses an algorithm dependent on the depth of the well. The algorithms were developed using API-JAS 2006 well cost data.

Options: The modeler can choose to turn on or off drilling costs. The cost values are calculated in the 'Drilling Costs' sheet, so any changes to the algorithm should be made there.

Tables 4.3 through 4.13 have the same input format with users putting in cost information either on a dollar per well basis or a dollar per foot per well basis.

4.3 Wireline (Geophysical) Logging

Purpose: This table, shown in Exhibit 24, allows the modeler to select wireline logging tools to use during well drilling. For each tool, a cost is given, if applicable, and the following column indicates whether or not the cost is applied (x = on, blank = off).

Options: The modeler can choose to turn on or off the wireline costs. Also, the modeler may decide to change the cost data to better available data or to specific analysis of the cost's impact.

Exhibit 24 Wireline Costs

Cost Parameter		Strat Test		Injection		Conversion of Strat Test to	
4.3 Wireline (Geophysical)	Resistivity* (Electrical) ($/ft/well)	0.75		0.75		0	
	Density* ($/ft/well)	0.75		0.75		0	
	Neutron* ($/ft/well)	0.75		0.75		0	
	Gamma Ray* ($/ft/well)					0	
	Spontaneous Potential* ($/ft/well)					0	
	Caliper* ($/ft/well)					0	
	Temperature* ($/ft/well)					0	
	Sonic* ($/ft/well)	0.75		0.75		0.75	
	Quad-Combo (includes *) ($/ft/well)	1.25	x	1.25	x	1.25	
	Triple-Combo (less Sonic) ($/ft/well)	0.9		0.9		0.9	
	Nuclear Magmetic Resonance (NMR) ($/ft/well)	0.75	x	0.75	x	0.75	
	Borehole Imaging ($/ft/well)	0.75	x	0.75	x	0.75	
	Casing Inspection Log ($/ft/well)	4.15		4.15	x	4.15	x
	Cement Bond Log ($/ft/well)	0.25		0.25	x	0.25	x
	Total for above rows ($/ft/well)	2.75		7.15		4.40	
Sub-total Row A	Cost per well for above rows ($/well)	13,887.50		32,532.50		20,020.00	
	Casing Inspection Log, Move In/Move Out Cost ($/well)	2070		2070	x	2070	x
Sub-total Row B	Total for above rows ($/well)	0.00		2,070.00		2,070.00	
for Back-End_Cost Items sheet	Sum of Sub-total Rows A and B above ($/well)	13,887.50		34,602.50		22,090.00	

Notes: Wireline (geophysical) costs are incurred in the year the well is drilled except as noted below for conversion of strat wells.
For strat wells converted to injection wells or deep monitoring wells, any conversion costs are incurred in the year the conversion occurs.
Data in row with label "for Back-End Cost Item sheet" are used in Back-End Cost Items sheet.

4.4 Core Recovery

Purpose: This table includes costs for core recovery. In addition to the costs per well for whole and sidewall, this table also contains inputs for the feet of core cut and the number of sidewall cores taken.

Options: The modeler can choose to turn on or off these recovery costs, which determine whether or not whole core and/or sidewall are taken. Also, the modeler may decide to change to cost data based on better available data or the amount of core taken.

4.5 Fluid Recovery

Purpose: This table includes costs for fluid sample recovery. A repeat formation testing wireline tool is used in deeper well, while a pump test is conducted in groundwater wells.

The inputs for this table consist of a number of samples per well for each well type and a unit cost for each sample. The table also contains selection cells, with the ability to turn fluid recovery costs on or off, next to the samples per well cells.

Options: The modeler can choose to change the number of samples taken or the cost for each sample as well as turn fluid recovery costs on or off for each type of well

4.6 Well Tests

Purpose: This table covers costs for a drillstem test (DST), pressure falloff test, and pump test. For each of these costs, the table includes a unit cost in dollars per well.

Options: The modeler can choose to turn on or off these costs or change their values. The modeler may also decide to apply these tests to different types of wells.

4.7 Well Seismic

Purpose: Specifies the use of the VSP tool in wells that are drilled (not for groundwater or Vadose Zone wells). The VSP costs are for the acquisition of VSP data and processing. **Options:** The modeler may decide to apply this cost by typing an 'x' into the selection cell column for various well types or to change the cost's value.

4.8 Analysis

Purpose: This table contains space for petrophysical analysis of well data. This analysis is a regulatory requirement for the injection wells when they are drilled and this cost is posted in Table 2.10 for this purpose. Also, costs for core analysis, geomechanical analysis or geochemical analysis of a fluid sample can be entered in this table. Cost poster here can also be applied to other well types.

Options: Since the default table does not contain cost information, the modeler may choose to not apply these costs (leave blank) or add cost values (enter 'x' to turn on cost) for the model.

4.9 Completion

Purpose: This table contains the items for completion of the well for injection, monitoring or eventually production, and disposal of water. The equipment listed is used in EPA's economic analysis of their Class VI rules. Cost for the well head and control equipment is currently a flat cost (EPA's algorithm was not used in this cost) which also includes the continuous monitoring equipment. While there is a distinction between surface casing and long string casing for cementing, that is not the situation for casing itself. Casing and tubing cost posted are for corrosion resistant steel. Well stimulation is listed but costs are currently not known. Casing and tubing diameter are used to calculate costs.

Options: The modeler will need to apply these costs to relevant wells and can change the cost per well or per foot per well for additional analysis. Also, the modeler may decide to change the diameter for casing or tubing.

4.10 Downhole Equipment for Wells

Purpose: This table posts costs incurred from sampling, testing, or monitoring reservoir properties as specified in the testing and monitoring plan or the post-injection site care and site closure plan. These costs will occur periodically during operations in support of AoR review as well as during post-injection site care.

Options: The modeler can choose to turn on or off these costs. Also, the modeler may decide to change to better available cost data or to specific analysis of the cost's impact.

The second timing table posted below Table 4.10 applies to Tables 4.20 through 4.30. These tables cover activities that may occur throughout the life of the well. This set of timing data is posted in rows 168 to 174.

4.20 Operations and Maintenance

Purpose: This table contains the annual operations and maintenance costs for the wells, which are from EPA's economic analysis of Class VI rules. These costs have a fixed annual component and per foot of well depth component. The frequency of occurrence of O&M or other tests can be adjusted by posting a value in 'Periodic' line immediately above this table (Exhibit 24) and other tables. The value entered here represents the number of years between work to be done or tests to be run.
Options: The modeler may decide to change to better available cost data or to specific analysis of the cost's impact.

Exhibit 25 Operation & Maintenance

	Cost Parameter	Strat Test		Injection		Conversion of Strat Test to	
	Periodic	1		1		1	
4.20 Operations & Maintenance:	Annual O&M Costs part A ($/well)			77500	x	77500	x
Row A	Annual O&M Costs part A ($/well)	0		77,500		77,500	
	Annual O&M Costs part B ($/ft/well)			3.1	x	3.1	x
	Annual O&M Costs part B ($/ft/well)	0.00		3.10		3.10	
Row B	Total Annual O&M Costs part B ($/well)	0		14,105		14,105	
for Back-End_Cost Items sheet	Total Annual O&M Costs for a Well (Rows A+B) ($/well)	0		91,605		91,605	

Notes: These are costs for operations and maintenance on wells.
These costs are annual costs incurred each year the well is utilized.
Data in row with label "for Back-End Cost Item sheet" are used in Back-End Cost Items sheet.

4.21 Annual Mechanical Integrity Test

Purpose: This table contains costs for the annual mechanical integrity test required by Class VI regulations. Available technology for this test includes pressure test, tracer survey, temperature log, noise log, and casing inspection log. For each of these items, the cost has a per-well component and a per-foot per-well component.
Options: The modeler may want to apply these tests/surveys to different types of wells depending on the chosen MVA plan. Also, the modeler may alter the cost for these items given either better information or analysis goals.

4.30 VSP Monitoring

Purpose: This table provides for posting the cost of conducting a VSP in the selected wells. The time table above Table 4.20 provides for running a VSP when the selected well is drilled and also periodically through the life of the well. A 'Periodic'

Options: Modeler may want to change costs if there is better or preferred data.

The third set of timing data applies to Tables 4.40 and 4.41. Costs posted in these tables are associated work done to improve storage efficiency and may occur annually or periodically.

4.40 Monitoring for Conformance Control

Purpose: Across the height of an injection interval, permeability will vary and the injected CO_2 will preferentially flow through the high permeable intervals, by-passing the low permeable intervals. Thus, pore space in low permeability intervals will be underutilized. This is referred to as a conformance problem and such problems can be detected by tests such as spinner surveys. The spinner survey is a wireline tool that can measure fluid velocity downhole in different intervals and be used to identify intervals that are not receiving much fluid. Monitoring to detect conformance issues is presumably done more frequently than the implementation of conformance control measures. These costs are classified as expenses.

Options: Modeler may want to change costs if there is better data or preferred data. Cost change may represent a suite of tools used here.

4.41 Conformance Control Implementation

Purpose: If conformance is an issue and the low permeability intervals are sufficiently distinct from the high permeability intervals and the two types of intervals are thick, then measures can be taken to improve conformance. This can involve additional coring and logging to better define the low and high permeability intervals. The low permeability intervals can be fracked to increase their permeability. Conformance control can also include injecting cement or polymers into high permeability intervals to decrease their permeability and encourage the injected fluids to flow into the underutilized low permeability intervals. Well work overs can also be done to enhance the permeability of the low permeability intervals. The category "Well work over and materials" is intended to cover the cost of cement or polymer, as well as the cost of well work overs. These costs are classified as capital costs.

Options: Modeler may want to change costs if there is better or preferred data.

The fourth set of timing data applies to Table 4.45. Costs posted in these tables are associated with adaptive reservoir management.

4.45 Adaptive Reservoir Management

Purpose: Adaptive reservoir management is the process of using site characterization data, geologic models, reservoir simulation models, injection data and monitoring data to better manage the injection of CO_2. Before injection begins, the operator will use site characterization data to construct a geologic model and reservoir simulation model. The operator will use the reservoir simulation model to predict the evolution of the CO_2 plume. This information will be used to establish the AOR. After injection begins, the operator will collect additional data as monitoring wells are installed and seismic surveys (or other geophysical methods) are conducted and this data can be used to improve the underlying geologic model and reservoir simulation model. The operator will also obtain information on the relationship between pressure and flow rates in injection wells and track the evolution of pressure propagation in monitoring wells. The evolution of the CO_2 plume will be tracked through seismic surveys (or other geophysical methods) and sampling from monitoring wells. The reservoir simulation model will be executed and the resulting CO_2 plume and pressure front compared to observed data. The model will be calibrated to better match observations. After calibration, the operator will be able to run scenarios where flows in one injection well may be increased and another decreased to better manage the CO_2 plume and better utilize available pore space for storing CO_2. This process is called adaptive reservoir management. It is assumed that there will be some additional costs each year for doing this analysis and for adjusting flow rates in injection wells. The operator will already be collecting and synthesizing much of this data for the periodic AOR review, so the modeling costs are primarily for using the reservoir simulation model to explore the implications of altering the flow rates in different injection wells. These costs are classified as expenses.

Options: Modeler may want to change costs if there is better or preferred data.

The fifth set of timing data applies to section 4.50. This table, which is the last of the well-drilling cost tables, covers costs at the end of the life of a well. Costs in Table 4.50 are applied when the well is plugged and abandoned, either at the end of site characterization for strat-wells, end of operations for injection wells, or end of post-injection site care for monitoring wells.

4.50 Plug and Abandon

Purpose: This table is the only well table that is applied at the end of well use. It includes all of the costs that deal with plugging and abandoning the wells. Items and costs are from EPA's economic analysis of Class VI regulations.
Options: Modeler may want to change costs if there is better or preferred data.

4.3 Geology Inputs

Geology inputs are found in the 'Geol Sal' worksheet. This sheet:

1. Specifies geologic properties of the injection formation.
2. Determines a CO_2 storage coefficient for a specified fraction of the injection formation, calculates the area of the CO_2 plume for this storage coefficient, and calculates the total mass of CO_2 that can be stored in the fraction of the injection formation where this storage coefficient is applicable.
3. Calculates the number of injection wells needed to inject the maximum daily mass of CO_2 to be injected.

The sections in this worksheet are described below.

Section 1: This section provides the overview of all other sections. The information in the following four paragraphs is included in section 1.

Section 2: Outputs or results from calculations in this sheet are presented in this section. These items includes geologic data; such as the depth to the top of the injection formation; thickness of the injection formation, CO_2 storage coefficient for a fraction of the injection formation, area of the CO_2 plume, mass of CO_2 that can be stored in the fraction of the injection formation that the CO_2 storage coefficient is applicable over, and the number of injection wells.

Section 3: All user inputs are specified in this section.

Section 4: The area of the CO_2 plume and the total mass of CO_2 that can be stored in this fraction of the injection formation are calculated in this section. The storage coefficient, determined in Section 2.5, is specified for a fraction of the injection formation and the total mass of CO_2 that can be stored is calculated for this fraction.

Section 5: The number of injection wells needed to inject a maximum daily mass of CO_2 is calculated in this section. A variety of methods are available for calculating the number of injection wells.

References for this worksheet are shown in Exhibit 26 below.

Exhibit 26 References

References
CCSTP, 2009. Carbon Management GIS: CO2 Injection Cost Modeling, by Carbon Capture and Sequestration Technologies Program (CCSTP), Massachusetts Institute of Technology, for National Energy Technology Laboratory, U.S. Department of Energy, August 2009.
Cinar, Y., O. Bukhteeva, P. Neal, W. Allinson, L. Paterson, 2008. CO2 Storage in Low Permeability Formations, presented at 2008 SPE/DOE Improved Oil Recovery Symposium, Tulsa Oklahoma, April 19-23, 2008, Society of Petroleum Engineers, SPE 114028.
Gorecki, C. et al., 2009. "Development of Storage Coefficients for CO2 Storage in Deep Saline Formations", for the IEA Greenhouse Gas R&D Programme (IEA GHG), report no. 2009/12, October 2009.
Morgan, D., 2011. "Properties of Supercritical Carbon Dioxide as Functions of Pressure and Temperature Implemented in Visual Basic", National Energy Technology Laboratory, U.S. Department of Energy, September 23, 2011 (draft).

Cell Color Conventions	
Inputs specified in this cell (Type in this cell)	
Intermediate value cells within an input table that are NOT input cells	
Intermediate values (Different colors used to distinguish rows, columns, or section	
Title or heading rows	
Overview or Instruction sections	
Cells directly referencing other modules (3 Modules = Activity, Geology, Financial)	
Geology module key outputs used in other sheets	
Geology module: other critical outputs or intermediate calculations	
Geological parameters from geology database	

Section 2 displays various outputs for the Geology Module.

- In Section 2.1, shown in Exhibit 27, the outputs for selected geologic properties of injection formation are shown such as region, surface area, and depths.
- In Section 2.2, items are calculated pertaining to CO_2 being stored such as total mass of CO_2 injected and average daily rate of CO_2 injection. This table is shown in Exhibit 28.

- In Section 2.3, the area of CO_2 plume and the mass of CO_2 that can be stored is calculated.
- In Section 2.4, the rate of injection of CO_2 in each injection well and number of injection wells is given. These items are shown in Exhibit 29.

Exhibit 27 Outputs

2. Outputs						
2.1 Selected Geologic Properties of Injection Formation						
Injection formation number	Form_num	270		See Section 3.4.1		
General Formation Characteristics						
Formation identifier	Form_ID	Frio - Middle1a		Frio - Middle1a		See Section 3.4.1
Formation name	Form_name	Frio - Middle		Frio - Middle		See Section 3.4.1
Formation state	Form_ST	TX		TX		See Section 3.4.1
Region	Form_Reg	Houston Coast Delta		Houston Coast Delta		See Section 3.4.1
Basin	Form_Basin	GC-Tertiary		GC-Tertiary		See Section 3.4.1
State-Basin	Form_ST_Basin	TX-GC Tertiary		TX-GC Tertiary		See Section 3.4.1
Large Region	Form_LrgReg	GC-TX Tertiary		GC-TX Tertiary		See Section 3.4.1
RCSP region	Form_RCSP	SECARB		SECARB		See Section 3.4.1
Lithology and Depositional Environment						
Lithology	Form_lith	Clastic		Clastic		See Section 3.4.1
Depositional environment	Form_dep	Delta		Delta		See Section 3.4.1
Geologic age	Form_age	Tertiary		Tertiary		See Section 3.4.1
Latitude and Longitude at Centroid of Surface Area						
Latitude at Centroid of Surface Area	Alat	-95.341952	degrees	-95.341952	degrees	See Section 3.4.1
Longitude at Centroid of Surface Area	Along	29.3976	degrees	29.3976	degrees	See Section 3.4.1
Surface Area						
Total surface area of injection formation	AForm	5,700	mi2	14,763	km2	See Section 3.4.1
Depths						
Depth to top of injection formation	Ltop	8,500	ft	2,591	m	See Section 3.4.1
Depth to midpoint of injection formation	Lmid	9,000	ft	2,743	m	See Section 3.4.1
Depth to bottom of injection formation	Lbot	9,500	ft	2,895	m	See Section 3.4.1
Thickness of injection formation	htot	1,000	ft	304.8	m	See Section 3.4.1
Temperature						
Temperature at top of injection formation	tmp	175	degF	353	degK	See Section 3.4.1
Lithostatic Pressure						
Lithostatic pressure at top of injection formation	Plith	8,500	psia	58.6	MPa	See Section 3.4.1
Fracture Pressure						
Fracture pressure at top of injection formation	Pfrac	5,100	psia	35.2	MPa	See Section 3.4.1
Ambient Hydrostatic Pressure						
Ambient hydrostatic pressure at top of injection formation	Pamb	3,944	psia	27.2	MPa	See Section 3.4.1
Porosity						
Porosity	npor	35%		35%		See Section 3.4.1
Permeability						
Horizontal permeability	kh	500	mD	500.0	mD	See Section 3.4.1
Vertical permeability	kv	150	mD	150.0	mD	See Section 3.4.1
Salinity						
Salinity	Csal	105,000	mg/L	105,000	mg/L	See Section 3.4.1

Exhibit 28 Storage of CO_2

2.3 Area of CO2 Plume and Mass of CO2 That Can be Stored				
Density of CO2	denCO2	702	kg/m3	See Section 4.1
Structure	Form_struct	Reg_dip		Options: General, Dome, Anticline, Incline_5deg, Incline_10deg, Flat See Section 3.5.1
Storage coefficient multiplier	multStorCoef	1		See Section 3.5.4
Selected storage coefficient without multiplier reflecting R&D influence	E(E)_noRD	5.57%		See Section 3.5.5
Selected storage coefficient including influence of R&D	E(E)	5.57%		See Section 3.5.5
Nominal maximum surface area for injection project	Aprojmax	100	mi2	See Section 3.2
CO2 Plume Uncertainty Area Multiplier (applied to CO2 Plume Area)	PlumeUnArmult	1.75		See Section 3.2
CO2 Pressure Front AOR Multiplier (applied to CO2 Plume Uncertainty Area)	PlumePrFAORmult	10.00		See Section 3.2
Nominal CO2 Plume Area and Other Areas				
CO2 Plume Area based on nominal CO2 injection rate	ACO2plnom	8.9	mi2	See Section 4.1
		23.0	km2	
CO2 Plume Uncertainty Area based on nominal CO2 injection rate	ACO2plUncnom	15.6	mi2	See Section 4.1
CO2 Pressure Front Area based on nominal CO2 injection rate	ACO2PresFrnom	155.6	mi2	See Section 4.1
3D Seismic Area based on nominal CO2 injection rate	A3DSeisnom	50.9	mi2	See Section 4.1
Actual CO2 Plume Area and Other Areas				
CO2 Plume Area	ACO2pl	8.9	mi2	See Section 4.1
		23.0	km2	
CO2 Plume Uncertainty Area	ACO2plUnc	15.6	mi2	See Section 4.1
CO2 Pressure Front Area	ACO2PresFr	155.6	mi2	See Section 4.1
3D Seismic Area	A3DSeis	50.9	mi2	See Section 4.1
Diameter of Actual Plume Areas and Ratio of Thickness to Diameter				
Diameter of CO2 Plume Area	d_CO2pl	3.36	mi	See Section 4.1
Ratio of thickness of formation to diameter of CO2 Plume Area	htot_d_CO2pl	0.0563		See Section 4.1
Diameter of CO2 Plume Uncertainty Area	d_CO2plUnc	4.45	mi	See Section 4.1
Ratio of thickness of formation to diameter of CO2 Plume Area	htot_d_CO2plUnc	0.0426		See Section 4.1
Maximum Mass of CO2 That Can be Stored in Formation and Formation-Structure Combination				
Fraction of injection formation with selected storage coefficient	PForm_struc	97.50%		See Section 3.5.6
Fraction of structure that can be used to store CO2	PAvail_struc	40.00%		See Section 3.5.7
Maximum surface area of formation-structure combination that can be used to store CO2	AFStrucmax	2,223.0	mi2	See Section 4.2
Fraction of total CO2 that can be stored in portion of formation with this storage coefficient that is used by project	frac_proj_form	0.40%		See Section 4.2
Maximum number of injection projects (injecting the mass given by mCO2tot) that can be implemented in the portion of the injection formation with this storage coefficient	Nproj	250.0		See Section 4.2
Maximum mass of CO2 that can theoretically be stored in this formation-structure combination based on maximum number of injection projects	mCO2FStrtot1	24,000,000,000	tonne	See Section 4.2
		24,000	Mtonne	
Maximum mass of CO2 that can theoretically be stored in formation	mCO2formtot	26,929,452,212	tonne	See Section 4.3
		26,929.5	Mtonne	
Mass of CO2 that can be stored in selected structure divided by total mass of CO2 that can be stored in injection formation	frac_CO2_struc	89.1%		See Section 4.3
Mass of CO2 injected by project (mCO2tot) divided by total mass of CO2 that can be stored in formation	frac_CO2_proj	0.36%		See Section 4.3

Exhibit 29 Rate of injection of CO_2

2.4 Rate of Injection of CO2 in Each Injection Well and Number of Injection Wells				
Results for selected method				
Maximum daily rate of CO2 injection	mCO2day	10,959	tonne/day	See Section 3.2
Maximum injection pressure at top of injection formation	Phydmax_top	4,590	psia	See Section 5.1
		31.6	MPa	
Selected method		Law and Bachu		See Section 5.1
Maximum CO2 injection rate per well that the formation can sustain	qwell_form	125,173	tonne/day	See Section 5.1
Maximum CO2 injection rate per well	qwell	3,660	tonne/day	See Section 5.1
Number of active injection wells	Nwell_actv	3		See Section 5.1
Number of injection wells	Nwell_fin	4		See Section 5.1
Annual average rate of CO2 injection per active injection well	mCO2acwlyr	1.07	Mtonne/yr-well	See Section 5.1
Maximum daily rate of CO2 injection per active injection well	mCO2acwldy	3,653	tonnes/day-well	See Section 5.1
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj	32.00	Mtonne/well	See Section 5.1
Results using Law and Bachu method for vertical wells				
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_LB	125,173	tonne/day	See Section 5.3
Maximum CO2 injection rate per well	qwell_LB	3,660	tonne/day	See Section 5.3
Number of active injection wells rounded up	Nwell_actv_LB	3		See Section 5.3
Number of injection wells	Nwell_fin_LB	4		See Section 5.3
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_LB	1.07	Mtonne/yr-well	See Section 5.3
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_LB	32.00	Mtonne/well	See Section 5.3
Results using ARI method for vertical wells				
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_ARI	180,103	tonne/day	See Section 5.4
Maximum CO2 injection rate per well	qwell_ARI	3,660	tonne/day	See Section 5.4
Number of active injection wells rounded up	Nwell_actv_ARI	3		See Section 5.4
Number of injection wells	Nwell_fin_ARI	4		See Section 5.4
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_ARI	1.07	Mtonne/yr-well	See Section 5.4
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_ARI	32.00	Mtonne/well	See Section 5.4
Results using Cinar et al. method for vertical, unfractured wells				
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_Cinvnofr	42,986	tonne/day	See Section 5.5.1
Maximum CO2 injection rate per well	qwell_Cinvnofr	3,660	tonne/day	See Section 5.5.1
Number of active injection wells rounded up	Nwell_actv_Cinvnofr	3		See Section 5.5.1
Number of injection wells	Nwell_fin_Cinvnofr	4		See Section 5.5.1
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_Cinvnofr	1.07	Mtonne/yr-well	See Section 5.5.1
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_Cinvnofr	32.00	Mtonne/well	See Section 5.5.1
Results using Cinar et al. method for vertical, fractured wells				
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_Cinvfr	304,133	tonne/day	See Section 5.5.2
Maximum CO2 injection rate per well	qwell_Cinvfr	3,660	tonne/day	See Section 5.5.2
Number of active injection wells rounded up	Nwell_actv_Cinvfr	3		See Section 5.5.2
Number of injection wells	Nwell_fin_Cinvfr	4		See Section 5.5.2
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_Cinvfr	1.07	Mtonne/yr-well	See Section 5.5.2
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_Cinvfr	32.00	Mtonne/well	See Section 5.5.2

In Section 3, the user specifies inputs related to geologic properties, CO_2 storage coefficients, and calculates the number of wells needed to inject the desired mass rate of CO_2 into the injection formation.

Section 3.1 provides a description of each section.

Section 3.2 reproduces inputs specified elsewhere that are needed to calculate the area of the CO_2 plume and the number of injection wells, as shown in Exhibit 30. Specifically, these inputs all relate to the nominal mass injection rate for CO_2 and the duration of injection. The actual annual mass rate of CO_2 injection can be different from the nominal value.

Section 3.3 provides general inputs related to geology, such as temperature and pressure gradients, and information needed to estimate the fracture pressure.

Section 3.4 allows the user to specify the geologic properties and parameters that are used in the rest of the geology inputs worksheet and in other sheets.

Section 3.5 allows the user to specify the CO_2 storage coefficient and the fraction of the injection formation for which this CO_2 storage coefficient is applicable.

Section 3.6 allows the user to specify the method used to calculate the mass rate of CO_2 that can be injected into a single well (either vertical or horizontal). This mass rate is used to calculate the number of wells needed to inject the maximum mass of CO_2 that the project is designed to handle. The inputs needed to perform the calculations for each method are specified in this section.

Exhibit 30 Inputs from other sheets

3.2 Inputs from Other Sheets				
Instructions: Section 3.2 reproduces inputs specified elsewhere, so the user does not need to input any additional information here.				
Factors Controlling Mass of CO2 to be Stored				
Years of injection of CO2	Injdur	30	yr	From Project Management sheet
Nominal annual mass rate of CO2 injection for project	mCO2nomyr	3,200,000	tonne/yr	From Project Management sheet
Multiplier for annual to maximum daily rate of CO2 injection	maxCO2mult	1.250		From Project Management sheet
Maximum daily rate of CO2 injection	mCO2maxdy	10,959	tonne/day	mCO2maxdy = mCO2yr*maxCO2mult/(365 days/yr)
Nominal maximum surface area for injection project	Aprojmax	100	mi2	From Project Management sheet
3.3 General Inputs Related to Geology				
Instructions: The user must specify values for each of the variables in this section.				
Parameters Controling the Choice of Porosity or Permeability Values				
Porosity value to use	PorCon	1		Options: 1=best estimate, 2=minimum, 3=maximum, all other=best estimate
Permeability value to use	PermCon	1		Options: 1=best estimate, 2=minimum, 3=maximum, all other=best estimate
Miscellaneous Geologic Parameters				
Surface temperature	tmp_surf	59	degF	Typical value is 59 degF
Temperature gradient	grad_tmp	1.37	degF/100ft	Typical value is 1.37 degF/ft
Lithostatic pressure gradient	grad_Plith	1	psia/ft	Typical value is 1 psia/ft
Ambient hydrostatic pressure gradient	grad_Phyd	0.464	psia/ft	Typical value is 0.464 psia/ft for brine
Fracture pressure factor	fact_Pfrac	60%		Typical value is 60%
Ratio of vertical permeability to horizontal permeability	fact_kv_h	0.3		Typical value is 0.3

Section 3.4 provides the basic geologic data used elsewhere in the cost model. This data is used in this worksheet, under 3.4.1, to calculate a variety of parameters that are critical for estimating CO_2 storage costs. Thus, accurately inputting data here is crucial. The user is given three ways to specify geologic data, each of which is described below. The table is shown in Exhibit 31.

- The most straightforward way for the user to select an injection formation is by specifying the number of a saline formation from the list of formations in sheet 'Geol DB Sal.' Once a formation number has been specified, the geologic data for that formation are extracted from this sheet and displayed in the purple-shaded cells in the column labeled 'Database.'
- The user may also directly input data for any of the geologic parameters by entering values in the column labeled 'Specified Value.'

For a few geologic parameters, values are calculated in Section 3.4.2 (shown in Exhibit 32) and the results are displayed in the column labeled 'Calculated Value.' Values are calculated for certain parameters because these parameters may not be specified in the sheet 'Geol DB Sal' (such as the temperature, hydrostatic pressure, or lithostatic pressure) and parameter values can be estimated. The user then selects the value that will be used for the parameter in the rest of the cost model. This step is done by entering a number in the column labeled 'Selection Control.' The actions associated with different numbers entered in this column are described in the column labeled 'Selection Control Options.' It should be noted that for the temperature and hydrostatic pressure parameters, if the user indicates the 'Database' value should be used and this value is 'NA,' then the 'Calculated Value' is used. There are no database values for lithostatic pressure, fracture pressure, or vertical permeability, so either 'Calculated Values' or 'Specified Values' are used.

When the macro for generating cost-supply data is executed, the 'Selection Control' is set to '1' for all parameters to force the model to use values in the database in sheet 'Geol DB Sal.' The user does not need to enter any data in Section 3.4.2, only 3.4.1.

Exhibit 31 Determination of geologic parameters

3.4.1 Determination of Geologic Parameters							
Injection formation number	Form_num	270		From Project Management sheet, references formation number in sheet "Geol DB Sal"			
Parameter	**Parameter Name**	**Database**	**Specified Value**	**Calculated Value**	**Selection Control**	**Selected Value**	**Units**
General Formation Characteristics							
Formation identifier	Form_ID	Frio - Middle1a	Glorietta2		1	Frio - Middle1a	
Formation name	Form_name	Frio - Middle	Glorietta		1	Frio - Middle	
Formation state	Form_ST	TX	NM		1	TX	
Region	Form_Reg	Houston Coast Delta	Permian - NW		1	Houston Coast Delta	
Basin	Form_Basin	GC-Tertiary	Permian		1	GC-Tertiary	
State-Basin	Form_ST_Basin	TX-GC Tertiary	Permian - NW		1	TX-GC Tertiary	
Large Region	Form_LrgReg	GC-TX Tertiary	Permian - NW		1	GC-TX Tertiary	
RCSP region	Form_RCSP	SECARB	SWP		1	SECARB	
Lithology and Depositional Environment							
Lithology	Form_lith	Clastic	Clastic		1	Clastic	
Depositional environment	Form_dep	Delta	Shallow Shelf		1	Delta	
Geologic age	Form_age	Tertiary	Permian		1	Tertiary	
Latitude and Longitude at Centroid of Surface Area							
Latitude at Centroid of Surface Area	Alat	-95.341952			1	-95.341952	degrees
Longitude at Centroid of Surface Area	Along	29.3976			1	29.3976	degrees
Surface Area							
Total surface area of injection formation	AForm	5,700	10,000		1	5700	mi2
Depths							
Depth to top of injection formation	Ltop	8,500	6,000		1	8500	ft
Depth to midpoint of injection formation	Lmid	9,000	6,200		1	9000	ft
Depth to bottom of injection formation	Lbot	9,500	6,400		1	9500	ft
Thickness of injection formation	htot	1,000	400		1	1000	ft
Temperature							
Temperature of injection formation at top of formation	tmp_top	NA	100	175	1	175	degF
Lithostatic Pressure							
Lithostatic pressure of injection formation at top of formation	Plith_top			8,500	1	8,500	psia
Ambient Hydrostatic Pressure							
Ambient hydrostatic pressure of injection formation at top of formation	Pamb_top	NA		3,944	3	3,944	psia
Fracture Pressure							
Fracture pressure at top of injection formation	Pfrac_top			5,100	1	5,100	psia
Porosity							
Porosity-value	npor	35%	14%		1	35%	
Porosity-best estimate	npor_best_est	35%	14%				
Porosity-minimum	npor_min	30%	12%				
Porosity-maximum	npor_max	40%	16%				
Permeability							
Horizontal permeability	kh	500	150		1	500	mD
Horizontal permeability-best-estimate	kh_best_est	500	150				mD
Horizontal permeability-minimum	kh_min	50	50				mD
Horizontal permeability-maximum	kh_max	6,000	400				mD
Vertical permeability	kv			150.0	1	150.0	mD
Salinity							
Salinity	Csal	105,000	50,000		1	105,000	mg/L

Exhibit 32 Calculation of various geologic parameters

3.4.2 Calculation of Various Geologic Parameters				
Temperature				
Surface temperature	tmp_surf	59	degF	See Section 3.3
Temperature gradient	grad_tmp	1.37	degF/100ft	See Section 3.3
Depth to top of injection formation	Ltop	8,500	ft	Selected depth to top of injection formation (See Section 3.4.1)
Calculated temperature at top of injection formation	tmp_top	175	degF	tmp = tmp_surf + grad_tmp * Lmid
Lithostatic Pressure				
Lithostatic pressure gradient	grad_Plith	1	psia/ft	See Section 3.3
Depth to top of injection formation	Ltop	8,500	ft	Selected depth to top of injection formation (See Section 3.4.1)
Calculated lithostatic pressure at top of injection formation	Plith_top	8,500	psia	Plith = grad_Plith * Ltop
Ambient Hydrostatic Pressure				
Ambient hydrostatic pressure gradient	grad_Phyd	0.464	psia/ft	See Section 3.3
Depth to top of injection formation	Ltop	8,500	ft	Selected depth to top of injection formation (See Section 3.4.1)
Calculated ambient hydrostatic pressure at top of injection formation	Pamb_top	3,944	psia	Pamb = grad_Phyd * Ltop
Fracture Pressure				
Fracture pressure factor	fact_Pfrac	60%		See Section 3.3
Lithostatic pressure gradient	grad_Plith	1	psia/ft	See Section 3.3
Depth to top of injection formation	Ltop	8,500	ft	Selected depth to top of injection formation (See Section 3.4.1)
Calculated fracture pressure at top of injection formation	Pfrac	5,100	psia	Pfrac = fact_Pfrac * grad_Plith * Ltop
Vertical Permeability				
Selected horizontal permeability	kh	500	mD	selected horizontal permeability
Ratio of vertical permeability to horizontal permeability	fact_kv_h	0.3		See Section 3.3
Calculated vertical permeability	kv	150.0	mD	kv = kh * fact_kv_h

In Section 3.5, the user selects the CO_2 storage coefficient that will be used in Section 3.4 to calculate the areal extent of the CO_2 plume. The user can determine the CO_2 storage coefficient by:

- In Section 3.5.1, shown in Exhibit 33, the user can use the CO_2 storage coefficient retrieved from the lookup table in Attachment A. The storage coefficient depends on the lithology and depositional environment for the injection formation and the structure and probability level specified by the user. The CO_2 storage coefficients in Attachment A are from Gorecki et al. (2009).
- In Section 3.5.2, the user can specify a storage coefficient directly.
- In Section 3.5.3, the user can specify values for the factors comprising the CO_2 storage coefficient and calculate the CO_2 storage coefficient from the product of these factors. Gorecki et al. (2009) discuss these factors and provide site-specific values for different types of geology.
- In Section 3.5.4, the user determines which of the CO_2 storage coefficients will be used for the rest of the cost model. This method is done by entering a number for the parameter 'Storage coefficient control.' The actions associated with different numbers entered for this parameter are described to the right of where the number is entered.
- In Section 3.5.5, the user specifies the fraction of the injection formation that has the storage coefficient specified in Section 3.5.4. This value mostly relates to the fraction of the injection formation that is assumed to have a particular kind of structure (such as dome, versus anticline, versus flat).

When the macro for generating cost-supply data is executed, the 'Storage coefficient control' is set to '1' to force the model to use lookup values based on the lithology data for injection formations in the database in sheet 'Geol DB Sal.'

Exhibit 33 Storage coefficient

3.5.1 Storage Coefficient from Lookup Table in Attachment A				
Lithology	Form_lith	Clastic		See Section 2.4.1
Depositional environment	Form_dep	Delta		See Section 2.4.1
Structure	Form_struct	Reg_dip		Options: General, Anticline, Dome, Incline_10deg, Incline_5deg, Flat Value specified in Project Management sheet
Selected probability level for lookup table of storage coefficients	E(E)_Pvalue	P50		Options: P10, P50 or P90 Value specified in Project Management sheet
Geology for CO2 storage coefficient look-up table	con_lu	clastic-delta-reg_dip		Used in lookup table in Attachment A below
Storage coefficient from lookup table based on lithology and depositional environment	E(E)lu	5.57%		See lookup table in Attachment A below
3.5.2 Specified Storage Coefficient				
Specified storage coefficient	E(E)sp	5.00%		
3.5.3 Calculated Storage Coefficient				
Net to total area ratio	E(An/At)	0.80		
Net to gross thickness ratio	E(hn/hg)	0.76		
Effective to total porosity ratio	E(ne/nt)	0.76		
Volumetric displacement efficiency	E(v)	0.22		
Microscopic displacement efficiency	E(d)	0.46		
Calculated storage coefficient	E(E)calc	4.68%		E(E)calc = E(An/At) * E(hn/hg) * E(ne/nt) * E(v) * E(d)

Exhibit 34 Determining the number of injection wells

3.6 Inputs Related to Determining the Number of Injection Wells				
Instructions: In this section, the user specifies the method used to calculate the mass rate of CO2 that can be injected into a single well (either vertical or horizontal). This mass rate is used to calculate the number of wells needed to inject the maximum mass of CO2 that the project is designed to handle on any given day. The inputs needed to perform the calculations for each method are specied in this section.				
Method used to determine number of injection wells	con_injwell_meth	1		Options: 1 = Law and Bachu method for vertical wells (default) 2 = ARI method for vertical wells 3 = Cinar method for vertical unfractured wells 4 = Cinar method for vertical fractured wells 5 = Cinar method for horizontal unfractured wells 6 = Cinar method for horizontal fractured wells
Maximum CO2 injection rate per well that the well mechanics can sustain	qwell_mech_yr	1,335,900	tonne/year	Rate expressed as annual rate (See Project_Management sheet)
	qwell_mech_day	3,660	tonne/day	Rate expressed as daily rate (See Project_Management sheet)
Relative permeability of CO2 in brine	krCO2	1		Assume this equals 1 for long injection duration (dries out reservoir around injection wells)
Fraction of fracture pressure that gives the maximum injection pressure	fact_Pinj	90%		Percentage of fracture pressure
Ratio of net thickness to total thickness of injection formation	fact_hn_tot	1.00		The Law and Bachu and ARI methods use total thickness in their calculations. The same assumption is used for the Cinar et al. methods.
Formation compressibility	compf	7.90E-05	1/psia	Typical value is 7.9e-5/psia (CCSTP, 2009)
Minimum number of injection wells	Nwell_min	4		There need to be at least 2 wells to allow wells to be taken out of service periodically for inspection and maintenance.
Fraction of additional injection wells needed to ensure sufficient wells are available during maintenance	fact_well_add	10%		
Brine viscosity in formation	visBr	0.4	cp	Cinar et al. (2008) assume a value of 0.4 cp
Radius of injection wellbore	rw	0.33	ft	Typical value is 0.33 ft or 4 inches
Viscosity control for Cinar methodology	con_vis	1		Options: 1 = use brine viscosity for effective viscosity of CO2 in formation all other = use viscosity of CO2 at pressure between ambient formation pressure and maximum injection pressure
Radius of effective drainage area of vertical injection well	re	1,640	ft	Cinar et al. (2008) assume a drainage area of 0.8 km2 or radius of 500 m or 1,640 ft
Fracture half length of vertical well	xf	985	ft	Cinar et al. (2008) assume a fracture half length of 300 m or 985 ft
Length of horizontal well	Lh	16,400	ft	Cinar et al. (2008) assume a horizontal well length of 5,000 m or 16,400 ft
Length of minor axis of drainage ellipse around horizontal well	bh	1,640	ft	Cinar et al. (2008) effectively assume a minor axis of 500 m or 1,640 ft
Number of fractures in horizontal well	Nhfr	18		Options: 2, 5, 10 or 18 (see Cinar et al. (2008))
Effective radius of fracture in horizontal well	rwhfr	80	ft	Cinar et al. (2008) indicates this parameter can be approximated by half the fracture half length (typical value is 50 m for fracture half length, so half this value is 25 m or approximately 80 ft)
Distance between outermost fractures in horizontal well	dhfr	683	ft	Not sure what typical values are, Cinar et al. (2008) do not provide values; estimated by dividing Lh by Nhfr and reducing further by multiplying by 0.75
4.0 Surface Area of CO2 Plume and Maximum Mass of CO2 Formation Can Theoretically Store				
Overview: Two items are calculated in this section. - In Section 4.1, the surface area of the CO2 plume is calculated. - In Section 4.2, the total mass of CO2 that can be stored in the formation is calculated.				

Section 4 shows calculations pertaining to the surface area of CO_2 plume and the maximum mass of CO_2 the formation can theoretically store.

- The surface area of the CO_2 plume is calculated in Section 4.1, shown in Exhibit 35.
- In Section 4.2, the total mass of CO_2 that can be stored in the formation is calculated. This table is shown in Exhibit 36.
- Storage coefficients for all structures and the volume of CO_2 and mass of CO_2 that can be theoretically stored are calculated in Section 4.3, shown in Exhibit 37.

Exhibit 35 Surface area of CO_2 plume

4.1 Surface Area of CO2 Plume				
Total Mass of CO2 Injected Over Duration of Project				
Years of injection of CO2	Injdur	30	yr	See Section 2.2
Annual mass rate of CO2 injection	mCO2yr	3,200,000	tonne/yr	See Section 2.2
Total mass of CO2 injected over duration of project	mCO2tot	96,000,000	tonne	mCO2tot = Injdur*mCO2yr
Basic Geologic Parameters				
Selected total or gross thickness of injection formation	htot	100	ft	See Section 2.4.1
		30.5	m	htot(m) = htot(ft) / (3.281 ft/m)
Selected porosity	npor	6%		See Section 2.4.1
Density of CO2 at Midpoint of Formation				
Selected temperature at top of injection formation	tmp_top	160	degF	See Section 2.4.1
Temperature gradient	grad_tmp	1.370	degF/100ft	See Section 2.3
Temperature at midpoint of injection formation	tmp_mid	161	degF	tmp_mid = tmp_top + 0.5*htot(ft)*(0.01 100 ft/ft)*grad_tmp
		345	degK	tmp_mid(degK) = 273.15 + (5/9) * (tmp_mid(degF)-32)
Selected ambient hydrostatic pressure at top of injection formation	Pamb_top	4665	psia	See Section 2.4.1
Ambient hydrostatic pressure gradient	grad_Phyd	0.464	psia/ft	See Section 2.3
Ambient hydrostatic pressure at midpoint of injection formation	Pamb_mid	4688	psia	Pamb_mid = Pamb_top + 0.5 * htot(ft) * grad_Phyd
		32.3	MPa	Pamb(MPa) = 0.0068948 MPa/psia * Pamb(psia)
Density of CO2	denCO2	800	kg/m3	Density at midpoint of formation for ambient (pre-injection) pressures; calculated with user-defined function denPRCO2 (Morgan, 2011) that determines density given pressure (in MPa) and temperature (in deg K).
Storage Coefficient				
Selected storage coefficient	E(E)	5.55%		See Section 2.5
Surface Area of CO2 Plume				
Surface area of CO2 plume	ACO2pl	1,182,246,187	m2	ACO2pl = mCO2tot * 1000 kg/tonne / (htot * npor * denCO2 * E(E))
		1,182.2	km2	ACO2pl(km2) = ACO2pl(m2) * 1e-6 km2/m2
		12,726,834,095	ft2	ACO2pl(ft2) = ACO2pl(m2) * (3.281 ft/m)^2
		292,168	acres	ACO2pl(acre) = ACO2pl(ft2) / 43560 ft2/acre
		456.5	mi2	ACO2pl(mi2) = ACO2pl(acre) / 640 acre/mi2

Exhibit 36 Comparison of total mass of CO_2 injected

4.2 Comparison of Total Mass of CO2 Injected to Total Mass of CO2 the Formation Can Theoretically Store				
Injection formation surface area	AForm	4,960	mi2	See Section 2.4.1
		12,846,340,480	m2	AForm(m2) = 2,589,988 m2/mi2 * AForm(mi2)
Total or gross thickness of injection formation	htot	30.5	m	See Section 4.1
Porosity	npor	6%		See Section 2.4.1
Maximum pore space of injection formation	Vpore	23,492,241,048	m3	Vpore = AForm * htot * npor
Selected storage coefficient	E(E)	5.55%		See Section 4.1
Maximum pore space theoretically available for storing CO2 at selected storage coefficient	VporeCO2	1,303,819,378	m3	VporeCO2 = Vpore * E(E)
Density of CO2 at midpoint of formation	denCO2	800	kg/m3	See Section 4.1
Fraction of injection formation with selected storage coefficient (mostly relates to fraction of injection formation with a particular structure)	frac_E(E)	32.5%		See Section 2.5.5
Area of formation with storage coefficient	AForm_E(E)	1,612	mi2	AForm_E(E) = AForm * frac_E(E)
		4,175	km2	Aform_E(E)(m2) = 2,589,988 m2/mi2 * Aform_E(E)(mi2)
Maximum mass of CO2 that can theoretically be stored in portion of formation with this storage coefficient	mCO2formptot	3.39.E+11	kg	mCO2formptot = VporeCO2 * denCO2 * frac_E(E)
		339,020,610	tonne	mCO2formptot(tonne) = mCO2formptot(kg) * 1e-3 tonne/kg
		339	million tonnes	mCO2formptot(mill. tonnes) = mCO2formptot(tonne) * 1e-6 mill. tonnes/tonne
Total Mass of CO2 injected over duration of project	mCO2tot	96,000,000	tonne	See Section 4.1
Fraction of total CO2 that can be stored in portion of formation with this storage coefficient that is used by project	frac_proj_form	28.32%		frac_proj_form = mCO2tot / mCO2formptot
Maximum number of injection projects (injecting the mass given by mCO2tot) that can be implemented in the portion of the injection formation with this storage coefficient	Nproj	3.5		Nproj = mCO2formptot / mCO2tot

Exhibit 37 Total stored CO_2

4.3 Total CO2 That Can be Stored in Injection Formation with Different Structures 4.3.1 Determine Storage Coefficient Weighted Over All Structures						
Lithology	Form_lith	Carbonate		See Section 2.4.1		
Depositional environment	Form_dep	Shallow Shelf		See Section 2.4.1		
Selected probability level for lookup table of storage coefficients	E(E)_Pvalue	P50		See Section 2.5.1 Options: P10, P50 or P90		
Formation structure	Anticline	Dome	Incline 10 Degrees	Incline 5 Degrees	Flat	No Specific Structure
	Anticline	Dome	Incline_10deg	Incline_5deg	Flat	NA
Geology for CO2 storage coefficient look-up table	carbonate-shallow shelf-anticline	carbonate-shallow shelf-dome	carbonate-shallow shelf-incline_10deg	carbonate-shallow shelf-incline_5deg	carbonate-shallow shelf-flat	carbonate-shallow shelf-na
Storage coefficient for this structure	8.64%	10.38%	6.46%	7.10%	5.55%	7.47%
Fraction of formation with this structure	1.3%	1.3%	32.5%	32.5%	32.5%	100.0%
Storage coefficient weighted by structure	E(E)wstruc	6.4%		E(E)wstruct is sum of storage coefficients for different structures weighted by the		
Storage coefficient for no specific structure	E(E)na	7.47%		E(E)na is storage coefficient specified above for a structure type of "NA"		
4.3.2 Determine Volume of CO2 and Mass of CO2 That Can Theoretically be Stored in Formation						
Structure	Form_struct	Flat		See Section 2.5.1		
Overall storage coefficient for formation	E(E)ov	6.45%		If Form_struct = NA, E(E)ov = E(E)na,		
Maximum pore space of injection formation	Vpore	23,492,241,048	m3	See Section 4.2		
Maximum pore space theoretically available for storing CO2	VporeCO2ov	1,514,897,164	m3	VporeCO2ov = Vpore * E(E)ov		
Density of CO2 at midpoint of formation	denCO2	800	kg/m3	See Section 4.1		
Maximum mass of CO2 that can theoretically be stored in formation	mCO2formtot	1.21.E+12	kg	mCO2formtot = VporeCO2ov * denCO2		
		1,212,016,300	tonne	mCO2formtot(tonne) = mCO2formtot(kg) * 1e-3 tonne/kg		
		1,212	million tonnes	mCO2formtot(mill. tonnes) = mCO2formtot(tonne) * 1e-6 mill. tonnes/tonne		
Mass of CO2 that can be stored in selected structure divided by total mass of CO2 that can be stored in injection formation	frac_CO2_struc	28.0%		frac_CO2_struc = mCO2formptot / mCO2formtot		
Mass of CO2 injected by project (mCO2tot) divided by total mass of CO2 that can be stored in formation	frac_CO2_proj	7.9%		frac_CO2_proj = mCO2tot / mCO2formtot		

In Section 5, the number of injection wells needed to inject a maximum daily mass of CO_2 into an injection formation is calculated. Three methods are provided for estimating the number of injection wells.

- In Section 5.1, the number of injection wells and rate of injection of CO_2 in each well for the selected method is presented as shown in Exhibit 38.
- In Section 5.2, a number of input parameters common to two or more of the three methods are provided as shown in Exhibit 38.
- In Section 5.3, the method developed by Law and Bachu (CCSTP, 2009) is used to calculate the number of vertical injection wells needed to inject the desired daily mass of CO_2 as shown in Exhibit 39. No enhancement to permeability from hydraulic fracking is provided in this method.
- In Section 5.4, the method developed by ARI (CCSTP, 2009) is used to calculate the number of vertical injection wells needed to inject the desired daily mass of CO_2 as shown in Exhibit 39. No enhancement to permeability from hydraulic fracking is provided in this method.
- In Section 5.5, the methods developed by Cinar et al. (2008) are used to calculate (see Exhibit 39):
  - the number of vertical injection wells without hydraulic fracking (Section 5.4.1)
  - the number of vertical injection wells with hydraulic fracking (Section 5.4.2)
  - the number of horizontal injection wells without hydraulic fracking (Section 5.4.3)
  - the number of horizontal injection wells with hydraulic fracking (Section 5.4.4)

Exhibit 38 Input values used to calculate number of injection wells

5.1 Number of Injection Wells and Rate of Injection of CO2 in Each Well for Selected Method				
Method used to determine number of injection wells	con_injwell_meth	1		Options: 1 = Law and Bachu method for vertical wells (default) 2 = ARI method for vertical wells 3 = Cinar method for vertical unfractured wells 4 = Cinar method for vertical fractured wells 5 = Cinar method for horizontal unfractured wells 6 = Cinar method for horizontal fractured wells
Selected method		Law and Bachu		See Section 3.6
Maximum CO2 injection rate per well that the formation can sustain	qwell_form	125,173	tonne/day	Depends on con_injwell_meth
Maximum CO2 injection rate per well	qwell	3,660	tonne/day	Depends on con_injwell_meth
Number of active injection wells rounded up	Nwell_actv	3		Depends on con_injwell_meth
Number of vertical injection wells	Nwell_fin	4		Depends on con_injwell_meth
Annual average rate of CO2 injection per active injection well	mCO2acwlyr	1.07	Mtonne/yr-well	Depends on con_injwell_meth
Maximum daily rate of CO2 injection per active injection well	mCO2acwldy	3,653	tonnes/day-well	mCO2acwldy = mCO2acwlyr * 1e6 tonnes/Mtonne * maxCO2mult / 365 days/yr
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj	32.00	Mtonne/well	Depends on con_injwell_meth
5.2 Input Values Common to More than One Method				
Duration of Injection Project				
Years of injection of CO2	Injdur	30	yr	See Section 3.2
Actual Mass Rate of CO2 Injection for Project (All Injection Wells)				
Actual annual mass rate of CO2 injection for project (all injection wells)	mCO2yr	3,200,000	tonne/yr	See Section 4.1
Multiplier for annual to maximum daily rate of CO2 injection	maxCO2mult	1.250		See Section 3.2
Maximum daily rate of CO2 injection for project (all injection wells)	mCO2maxdy	10,959	tonne/day	mCO2maxdy = mCO2yr*maxCO2mult/(365 days/yr)
Formation Permeabilities				
Selected horizontal permeability	kh	500.0	mD	See Section 3.4.1
Selected vertical permeability	kv	150.0	mD	See Section 3.4.1
Overall permeability	kabs	273.9	mD	kabs = (kh * kv)^0.5
Formation Total and Net Thickness				
Thickness of injection formation	htot	1,000	ft	See Section 3.4.1
		304.8	m	htot(m) = htot(ft) / (3.281 ft/m)
Ratio of net thickness to total thickness of injection formation	fact_hn_tot	1.00		See Section 3.6
Net thickness of injection formation	hnet	1,000.0	ft	hnet = fact_hn_tot * htot
		304.8	m	hnet(m) = hnet(ft) / (3.281 ft/m)
Formation Ambient Hydrostatic Pressure and Maximum Injection Pressure				
Ambient hydrostatic pressure at midpoint in injection formation	Pamb_mid	4,176	psia	See Section 4.1
		28.8	MPa	
Fracture pressure at top of injection formation	Pfrac_top	5,100	psia	See Section 3.4.1
Fraction of fracture pressure that gives the maximum injection pressure	fact_Pinj	90%		See Section 3.6
Maximum injection pressure at top of injection formation	Phydmax_top	4,590	psia	Phydmax_top = fact_Pinj * Pfrac_top
Ambient hydrostatic pressure gradient	grad_Phyd	0.464	psia/ft	See Section 3.3
Maximum injection pressure at midpoint of injection formation	Phydmax_mid	4822	psia	Phydmax_mid = Phydmax_top + 0.5*htot(ft)*grad_Phyd
		33.2	MPa	Phydmax_mid(MPa) = 0.0068948 MPa/psia * Phydmax_mid(psia)
Viscosity of CO2 in Injection Formation				
Temperature at midpoint of injection formation	tmp_mid	357	degK	See Section 4.1
		642	degR	tmp_mid(degR) = (9/5)*tmp_mid(degK)
Viscosity of CO2 at ambient hydrostatic pressure at midpoint in injection formation	visCO2amb_mid	5.81E+01	uPa-s	Viscosity at midpoint of injection formation for ambient (pre-injection) pressures utilizing user-defined function visPRCO2 (Morgan, 2011) that determines viscosity given density of CO2 (in kg/m3) and temperature (in deg K). Density depends on pressure and temperature.
		5.81E-02	cp	visCO2amb_mid(cp) = 0.001 cp/uPa-s * visCO2amb_mid(uPa-s)
Viscosity of CO2 at maximum injection pressure at midpoint of injection formation	visCO2inj_mid	6.54E+01	uPa-s	Viscosity at midpoint of injection formation for maximum injection pressure utilizing user-defined function visPRCO2 (Morgan, 2011) that determines viscosity given density of CO2 (in kg/m3) and temperature (in deg K). Density depends on pressure and temperature.
		6.54E-02	cp	visCO2inj_mid(cp) = 0.001 cp/uPa-s * visCO2inj_mid(uPa-s)
Average viscosity of CO2 in plume	visCO2av_mid	6.18E-02	cp	visCO2av_mid = 0.5 * (visCO2amb_mid + visCO2inj_mid)

Exhibit 39 Various methods used to calculate number of injection wells

5.3 Law and Bachu Methodology for Vertical Injection Wells				
Inputs to Calculations				
Injectivity coefficient	coef_LB	0.0208	(tonne/day-m-MPa)/(mD/cp)	From paper by Law and Bachu (1996), CCSTP (2009)
Overall permeability	kabs	273.9	mD	See Section 5.2
Average viscosity of CO2 in plume	visCO2av_mid	6.18E-02	cp	See Section 5.2
Net thickness of injection formation	hnet	304.8	m	See Section 5.2
Ambient hydrostatic pressure at midpoint in injection formation	Pamb_mid	28.8	MPa	See Section 5.2
Maximum injection pressure at midpoint of injection formation	Phydmax_mid	33.2	MPa	See Section 5.2
Maximum Rate of CO2 Injection per Vertical Injection Well				
Injectivity	qinj_LB	92.21	(tonne/day-m-MPa)	qinj_LB = coef_LB * kabs / visCO2av_mid
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_LB	125,173	tonne/day	qwell_form_LB = qinj_LB * hnet * (Phydmax_mid - Pamb_mid)
Maximum CO2 injection rate per well that the well mechanics can sustain	qwell_mech_day	3,660	tonne/day	See Section 3.6
Maximum CO2 injection rate per well	qwell_LB	3,660	tonne/day	qwell_LB = min(qwell_form_LB, qwell_mech_day)
Number of Vertical Injection Wells Needed				
Maximum daily rate of CO2 injection for project (all injection wells)	mCO2maxdy	10,959	tonne/day	See Section 5.2
Number of active injection wells rounded up	Nwell_actv_LB	3		Nwell_actv_LB = Roundup(mCO2maxdy / qwell_LB)
Fraction of additional injection wells needed to ensure wells are available during maintenance	fact_well_add	10%		See Section 3.6
Number of wells, including backup wells to operate during well maintenance, rounded up	Nwell_fin_a	4		Nwell_fin_a = roundup(Nwell_actv_LB * (1+fact_well_add))
Minimum number of injection wells	Nwell_min	4		See Section 3.6
Number of vertical injection wells	Nwell_fin_LB	4		If Nwell_fin_a <= Nwell_min, then Nwell_fin_LB = Nwell_min else, Nwell_fin_LB = Nwell_fin_a
Mass of CO2 Injected per Active Injection Well				
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_LB	1.07	Mtonne/yr-well	mCO2acwlyr_LB = mCO2yr * 1e-6 Mtonne/tonne / Nwell_actv_LB
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_LB	32.00	Mtonne/well	mCO2acwlprj_LB = mCO2acwlyr_LB * Injdur

5.4 ARI Methodology for Vertical Injection Wells				
Inputs to Calculations				
Constant factor 1	c1	2.64E-04	cp-ft/(psia-mD-hr)	From paper by CCSTP (2009)
Constant factor 2	c2	1.42E+06	(psia2/cp)-mD-ft-degR_MMscf/day	From paper by CCSTP (2009)
Ambient hydrostatic pressure at midpoint in injection formation	Pamb_mid	4,176	MPa	See Section 5.2
		28.8	MPa	See Section 5.2
Maximum injection pressure at midpoint of injection formation	Phydmax_mid	4822	psia	See Section 5.2
		33.2	MPa	See Section 5.2
Temperature of at midpoint of formation	tmp_mid	357	degK	See Section 5.2
		642	degR	See Section 5.2
Overall permeability	kabs	273.9	mD	See Section 5.2
Relative permeability	krCO2	1		See Section 3.6
Selected porosity	npor	35%		See Section 3.4.1
Net thickness of injection formation	hnet	1,000.0	ft	See Section 5.2
Duration of injection	Injdur	30	yr	See Section 3.2
		262,800	hrs	Injdur(hr) = Injdur(yr) * 365 days/yr * 24 hrs/day
Formation compressibility	compf	7.90E-05	1/psia	See Section 3.6
Radius of wellbore	rw	0.33	ft	See Section 3.6
Viscosity of CO2 at ambient hydrostatic pressure	visCO2amb_mid	5.81E-02	cp	See Section 5.2
Maximum Rate of CO2 Injection per Vertical Injection Well				
Dimensionless time parameter	tD	1.08E+11		tD = c1 * kabs * Injdur(hrs) / (npor * visCO2amb_mid * compf * rw^2)
Dimensionless Pt parameter	Pt	1.31E+01		Pt = 0.5 * ln(tD + 0.80907)
Pseudo pressure difference	del_psi	1.49E+08	psia2/cp	See calculations to right
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_ARI	3413.0	MMscf/day	qwell_form_ARI = del_psi * kabs * hnet / (c2 * tmp_mid(degR) * Pt)
		180,103	tonne/day	qwell_form_ARI(tonne/day) = qwell_form_ARI(MMscf/day) / (0.01895 MMscf/tonne)
Maximum CO2 injection rate per well that the well mechanics can sustain	qwell_mech_day	3,660	tonne/day	See Section 3.6
Maximum CO2 injection rate per well	qwell_ARI	3,660	tonne/day	qwell_ARI = min(qwell_form_ARI, qwell_mech_day)
Number of Vertical Injection Wells Needed				
Maximum daily rate of CO2 injection for project (all injection wells)	mCO2maxdy	10,959	tonne/day	See Section 5.2
Number of active injection wells rounded up	Nwell_actv_ARI	3		Nwell_actv_ARI = Roundup(mCO2maxdy / qwell_ARI)
Fraction of additional injection wells needed to ensure wells are available during maintenance	fact_well_add	10%		See Section 3.6
Number of injection wells, including backup wells to operate during well maintenance, rounded up	Nwell_fin_a	4		Nwell_fin_a = roundup(Nwell_actv_ARI * (1+fact_well_add))
Minimum number of injection wells	Nwell_min	4		See Section 3.6
Number of vertical injection wells	Nwell_fin_ARI	4		If Nwell_fin_a <= Nwell_min, then Nwell_fin_ARI = Nwell_min else, Nwell_fin_ARI = Nwell_fin_a
Mass of CO2 Injected per Active Injection Well				
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_ARI	1.07	Mtonne/yr-well	mCO2acwlyr_ARI = mCO2yr * 1e-6 Mtonne/tonne / Nwell_actv_ARI
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_ARI	32.00	Mtonne/well	mCO2acwlprj_ARI = mCO2acwlyr_ARI * Injdur

5.5 Cinar et al. Methodology for Vertical and Horizontal Injection Wells with and without Hydraulic Fracking				
Inputs Common to All Calculations				
Constant factor 3	c3	7.08E-03	(bbl/day)-cp/(mD-ft-psia)	
Constant factor 4	c4	5.02E+00	(psia/degR)-(bbl/Mscf)	
Ambient hydrostatic pressure at midpoint in injection formation	Pamb_mid	4,176	MPa	See Section 5.2
		28.8	MPa	
Maximum injection pressure at midpoint of injection formation	Phydmax_mid	4822	psia	See Section 5.2
		33.2	MPa	
Average fluid pressure (average of ambient hydrostatic pressure and maximum injection pressure) at midpoint of injection formation	Pavg_mid	4,499.0	psia	Pavg_mid = 0.5 * (Phydmax_mid + Pamb_mid)
		31.0	MPa	
Temperature of at midpoint of formation	tmp_mid	357	degK	See Section 5.2
		642	degR	
Overall permeability	kabs	273.9	mD	See Section 5.2
Relative permeability	krCO2	1		See Section 3.6
Selected porosity	npor	35%		See Section 3.4.1
Net thickness of injection formation	hnet	1,000.0	ft	See Section 5.2
Radius of effective drainage area of injection well	re	1,640	ft	See Section 5.2
Viscosity of CO2 at average fluid pressure at midpoint of injection formation	visCO2avP_mid	6.18E+01	uPa-s	Viscosity at midpoint of injection formation for average fluid pressure of injection formation utilizing user-defined function visPRCO2 (Morgan, 2011) that determines viscosity given density of CO2 (in kg/m3) and temperature (in deg K). Density depends on pressure and temperature.
		6.18E-02	cp	
Brine viscosity in formation	visBr	0.4	cp	See Section 3.6
Viscosity control for Cinar methodology	con_vis	1		See Section 3.6
Effective viscosity used in calculations	viseff	0.4	cp	If con_vis = 1 , then: viseff= visBr else: viseff = visCO2avP_mid
Compressibility factor for CO2 at midpoint pressure	zfact	0.630		Compressibility factor for CO2 at midpoint of injection formation utilizing user-defined function zfactPRCO2 (Morgan, 2011). The function zfact determines the compressibility factor given the temperature (in deg K) at the midpoint of the injection the formation (tmp_mid) and the average pressure (Pavg_mid) at the midpoint of injection formation (Pavg_mid).
Gas formation volume factor	Bg	0.452	bbl/Mscf	Bg = c4 * zfact * tmp_mid(degR) / Pavg_mid(psia)
5.5.1 Calculations for Vertical Injection Well with No Hydraulic Fracturing				
Inputs to Calculations				
Radius of wellbore	rw	0.33	ft	See Section 3.6
Maximum Rate of CO2 Injection per Vertical Injection Well (no fracking)				
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_Cinvnofr	814,584	Mscf/day	qwell_form_Cinvnofr(Mscf/day) = c3 * kabs * krCO2 * hnet * (Phydmax_mid (psia) - Pamb_mid(psia)) / (Bg * viseff * ln(re/rw))
		42,986	tonne/day	qwell_form_Cinvnofr(Mscf/day) = qwell_form_Cinvnofr(Mscf/day) * 0.001 MMscf/Mscf
Maximum CO2 injection rate per well that the well mechanics can sustain	qwell_mech_day	3,660	tonne/day	See Section 3.6
Maximum CO2 injection rate per well	qwell_Cinvnofr	3,660	tonne/day	qwell_Cinvnofr = min(qwell_form_Cinvnofr, qwell_mech_day)
Number of Vertical Injection Wells Needed (no fracking)				
Maximum daily rate of CO2 injection for project (all injection wells)	mCO2maxdy	10,959	tonne/day	See Section 5.2
Number of active injection wells rounded up	Nwell_actv_Cinvnofr	3		Nwell_actv_Cinvnofr = Roundup(mCO2maxdy / qwell_Cinvnofr)
Fraction of additional injection wells needed to ensure wells are available during maintenance	fact_well_add	10%		See Section 5.2
Number of injection wells, including backup wells to operate during well maintenance, rounded up	Nwell_fin_a	4		Nwell_fin_a = roundup(Nwell_actv_Cinvnofr * (1+fact_well_add))
Minimum number of injection wells	Nwell_min	4		See Section 3.6
Number of vertical injection wells	Nwell_fin_Cinvnofr	4		If Nwell_fin_a <= Nwell_min, then Nwell_fin_LB = Nwell_min else, Nwell_fin_LB = Nwell_fin_a
Mass of CO2 Injected per Active Injection Well				
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_Cinvnofr	1.07	Mtonne/yr-well	mCO2acwlyr_Cinvnofr = mCO2yr * 1e-6 Mtonne/tonne / Nwell_actv_Cinvnofr
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_Cinvnofr	32.00	Mtonne/well	mCO2acwlprj_Cinvnofr = mCO2acwlyr_Cinvnofr * Injdur

5.5.2 Calculations for Vertical Injection Well with Hydraulic Fracturing				
Inputs to Calculations				
fracture half length of wellbore	xf	985.0	ft	See Section 3.6
Effective radius of wellbore	rweff	492.5	ft	rweff = 0.5 * xf
Maximum Rate of CO2 Injection per Vertical Injection Well (with fracking)				
Maximum CO2 injection rate per well that the formation can sustain	qwell_form_Cinvfr	5,763,314	Mscf/day	qwell_form_Cinvfr(Mscf/day) = c3 * kabs * krCO2 * hnet * (Phydmax_mid (psia) - Pamb_mid(psia)) / (Bg * viseff * ln(re/rweff))
		304,132.7	tonne/day	qwell_Cinvfr(Mscf/day) = qwell_Cinvfr(Mscf/day) * 0.001 MMscf/Mscf / (0.01895 MMscf/tonne)
Maximum CO2 injection rate per well that the well mechanics can sustain	qwell_mech_day	3,660	tonne/day	See Section 3.6
Maximum CO2 injection rate per well	qwell_Cinvfr	3,660	tonne/day	qwell_Cinvfr = min(qwell_form_Cinvfr, qwell_mech_day)
Number of Vertical Injection Wells Needed (with fracking)				
Maximum daily rate of CO2 injection for project (all injection wells)	mCO2maxdy	10,959	tonne/day	See Section 5.2
Number of active injection wells rounded up	Nwell_actv_Cinvfr	3		Nwell_actv_Cinvfr = Roundup(mCO2maxdy / qwell_Cinvfr)
Fraction of additional injection wells needed to ensure wells are available during maintenance	fact_well_add	10%		See Section 3.6
Number of injection wells, including backup wells to operate during well maintenance, rounded up	Nwell_fin_a	4		Nwell_fin_a = roundup(Nwell_actv_Cinvfr * (1+fact_well_add))
Minimum number of injection wells	Nwell_min	4		See Section 3.6
Number of vertical injection wells	Nwell_fin_Cinvfr	4		If Nwell_fin_a <= Nwell_min, then Nwell_fin_Cinvfr = Nwell_min else, Nwell_fin_Cinvfr = Nwell_fin_a
Mass of CO2 Injected per Active Injection Well				
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_Cinvfr	1.07	Mtonne/yr-well	mCO2acwlyr_Cinvfr = mCO2yr * 1e-6 Mtonne/tonne / Nwell_actv_Cinvfr
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_Cinvfr	32.00	Mtonne/well	mCO2acwlprj_Cinvfr = mCO2acwlyr_Cinvfr * Injdur
5.5.3 Calculations for Horizontal Injection Well with No Hydraulic Fracturing				
Inputs to Calculations				
Radius of wellbore	rw	0.33	ft	See Section 3.6
Length of horizontal well	Lh	16,400	ft	See Section 3.6
Length of minor axis of drainage ellipse around horizontal well	bh	1,640	ft	See Section 3.6
Drainange area of eliptical area around horizontal well	Ahdrain	62,241,628	ft2	Ahdrain = 2 * Lh * bh + pi * bh^2
Effective drainage radius for horizontal well	reh	4,451	ft	reh = sqrt(Ahdrain/pi)
Length of major axis of drainage ellipse around horizontal well	ah	8,523	ft	ah = (Lh/2) * sqrt[0.5 + sqrt{ 0.25 + (2 * reh / Lh)^4 }]
Effective wellbore radius for horizontal well	rwheff	2,153	ft	rwheff = reh * (Lh/2) / { [hnet / (2*rw)]^(hnet/Lh) * [ah + sqrt(ah^2 - (Lh/2)^2)] }
Maximum Rate of CO2 Injection per Horizontal Injection Well (no fracking)				
Maximum CO2 injection rate per well	qwell_form_Cinhnofr	9,544,971	Mscf/day	qwell_form_Cinhnofr(Mscf/day) = c3 * kabs * krCO2 * hnet * (Phydmax_mid (psia) - Pamb_mid(psia)) / (Bg * viseff * ln(reh/rwheff))
		503,692.4	tonne/day	qwell_form_Cinhnofr(Mscf/day) = qwell_form_Cinhnofr(Mscf/day) * 0.001 MMscf/Mscf / (0.01895 MMscf/tonne)
Maximum CO2 injection rate per well that the well mechanics can sustain	qwell_mech_day	3,660	tonne/day	See Section 3.6
Maximum CO2 injection rate per well	qwell_Cinhnofr	3,660	tonne/day	qwell_Cinhnofr = min(qwell_form_Cinhnofr, qwell_mech_day)
Number of Horizontal Injection Wells Needed (no fracking)				
Maximum daily rate of CO2 injection	mCO2maxdy	10,959	tonne/day	See Section 3.2
Number of active injection wells rounded up	Nwell_actv_Cinhnofr	3		Nwell_actv_Cinhnofr = Roundup(mCO2maxdy / qwell_Cinhnofr)
Fraction of additional injection wells needed to ensure wells are available during maintenance	fact_well_add	10%		See Section 3.6
Number of injection wells, including backup wells to operate during well maintenance, rounded up	Nwell_fin_a	4		Nwell_fin_a = roundup(Nwell_actv_Cinhnofr * (1+fact_well_add))
Minimum number of injection wells	Nwell_min	4		See Section 3.6
Number of horizontal injection wells	Nwell_fin_Cinhnofr	4		If Nwell_fin_a <= Nwell_min, then Nwell_fin_Cinhnofr = Nwell_min else, Nwell_fin_Cinhnofr = Nwell_fin_a
Mass of CO2 Injected per Active Injection Well				
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_Cinhnofr	1.07	Mtonne/yr-well	mCO2acwlyr_Cinhnofr = mCO2yr * 1e-6 Mtonne/tonne / Nwell_actv_Cinhnofr
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_Cinhnofr	32.00	Mtonne/well	mCO2acwlprj_Cinhnofr = mCO2acwlyr_Cinhnofr * Injdur

5.5.4 Calculations for Horizontal Injection Well with Hydraulic Fracturing				
Inputs to Calculations				
Radius of wellbore	rw	0.33	ft	See Section 3.6
Length of horizontal well	Lh	16,400	ft	See Section 3.6
Length of minor axis of drainage ellipse around horizontal well	bh	1,640	ft	See Section 3.6
Drainange area of eliptical area around horizontal well	Ahdrain	62,241,628	ft2	Ahdrain = 2 * Lh * bh + pi * bh^2
Effective drainage radius for horizontal well	reh	4,451	ft	reh = sqrt(Ahdrain/pi)
Number of fractures in horizontal well	Nhfr	18		See Section 3.6
Effective radius of fracture in horizontal well	rwhfr	80	ft	See Section 3.6
Distance between outermost fractures in horizontal well	dhfr	683	ft	See Section 3.6
Constant factor 5	c5	0.0635		See lookup table to the right
Constant factor 6	c6	0.3453		See lookup table to the right
Effective radius of wellbore taking fracking into account	rwhfeff	20.7	ft	rwheff = c5 * dhfr * (rwhfr / dhfr)^c6
Maximum Rate of CO2 Injection per Horizontal Injection Well (with fracking)				
Maximum CO2 injection rate per well	qwell_form_Cinhfr	1,290,755	Mscf/day	qwell_form_Cinhfr(Mscf/day) = c3 * kabs * krCO2 * hnet * (Phydmax_mid (psia) - Pamb_mid(psia)) / (Bg * viseff * ln(reh/rwhfeff))
		68,113.7	tonne/day	qwell_form_Cinhfr(Mscf/day) = qwell_form_Cinhfr(Mscf/day) * 0.001 MMscf/Mscf / (0.01895 MMscf/tonne)
Maximum CO2 injection rate per well that the well mechanics can sustain	qwell_mech_day	3,660	tonne/day	See Section 3.6
Maximum CO2 injection rate per well	qwell_Cinhfr	3,660	tonne/day	qwell_Cinhfr = min(qwell_form_Cinhfr, qwell_mech_day)
Number of Horizontal Injection Wells Needed (with fracking)				
Maximum daily rate of CO2 injection	mCO2maxdy	10,959	tonne/day	See Section 3.2
Number of active injection wells rounded up	Nwell_actv_Cinhfr	3		Nwell_actv_Cinhfr = Roundup(mCO2maxdy / qwell_Cinhfr)
Fraction of additional injection wells needed to ensure wells are available during maintenance	fact_well_add	10%		See Section 3.6
Number of injection wells, including backup wells to operate during well maintenance, rounded up	Nwell_fin_a	4		Nwell_fin_a = roundup(Nwell_actv_Cinhfr * (1+fact_well_add))
Minimum number of injection wells	Nwell_min	4		See Section 3.6
Number of horizontal injection wells	Nwell_fin_Cinhfr	4		If Nwell_fin_a <= Nwell_min, then Nwell_fin_Cinhfr = Nwell_min else, Nwell_fin_Cinhfr = Nwell_fin_a
Mass of CO2 Injected per Active Injection Well				
Annual average rate of CO2 injection per active injection well	mCO2acwlyr_Cinhfr	1.07	Mtonne/yr-well	mCO2acwlyr_Cinhfr = mCO2yr * 1e-6 Mtonne/tonne / Nwell_actv_Cinhfr
Mass of CO2 injected over the duration of the project averaged over active injection wells	mCO2acwlprj_Cinhfr	32.00	Mtonne/well	mCO2acwlprj_Cinhfr = mCO2acwlyr_Cinhfr * Injdur

Attachment A (Exhibit 40):

Overview: The CO_2 storage coefficients in this table were obtained from the report prepared by IEA GHG (2009). The values in the first 21 rows are from Table 13 of the referenced report. The values in the remaining rows are from Appendix E of the referenced report.

Exhibit 40 Lookup table

Attachment A: Lookup Table for Site-specific CO2 Storage Coefficients Based on Lithology, Depositional Environment and Structure						
Lithology	Depositional Environment	Structure	Lithology-Depositional Environment	Storage Coefficient (P10)	Storage Coefficient (P50)	Storage Coefficient (P90)
Clastic	NA	NA	clastic-na-na	4.62%	6.79%	14.92%
Dolomite	NA	NA	dolomite-na-na	6.57%	7.91%	14.92%
Limestone	NA	NA	limestone-na-na	4.36%	6.13%	9.83%
Clastic	Eolian	NA	clastic-eolian-na	5.64%	7.44%	15.86%
Clastic	Fluvial	NA	clastic-fluvial-na	5.13%	6.44%	12.50%
Clastic	Peritidal	NA	clastic-peritidal-na	4.12%	6.06%	15.41%
Clastic	Slope basin	NA	clastic-slope basin-na	4.89%	7.39%	16.98%
Clastic	Shallow shelf	NA	clastic-shallow shelf-na	5.41%	7.67%	15.62%
Clastic	Shelf	NA	clastic-shelf-na	4.07%	6.23%	17.23%
Clastic	Strandplain	NA	clastic-strandplain-na	5.40%	6.72%	12.90%
Limestone	Peritidal	NA	limestone-peritidal-na	4.45%	5.61%	9.41%
Limestone	Reef	NA	limestone-reef-na	4.09%	5.31%	9.00%
Limestone	Shallow shelf	NA	limestone-shallow shelf-na	4.70%	7.47%	10.59%
Carbonate	Peritidal	NA	carbonate-peritidal-na	4.45%	5.61%	9.41%
Carbonate	Reef	NA	carbonate-reef-na	4.09%	5.31%	9.00%
Carbonate	Shallow shelf	NA	carbonate-shallow shelf-na	4.70%	7.47%	10.59%
Dolomite	Peritidal	NA	dolomite-peritidal-na	6.57%	7.91%	14.92%
Dolomite	Reef	NA	dolomite-reef-na	6.57%	7.91%	14.92%

For additional information on the FE NETL CTS Cost Model not provided in this manual, please refer to notes and references in the model itself.

Water Worksheet

This sheet provides calculations related to water production (or withdrawal), treatment and re-injection (or disposal). This sheet is included as part of the Geology Module because it includes a number of engineering calculations that depend on geology data. However, this sheet also includes cost information that is eventually passed to the Activity Cost Module and water price information that is passed to the Financial Module. The sections of this sheet with letter labels (Part A through Part F) have geology data or engineering calculations. The sections of this sheet with number labels 6.1 through 6.4 calculate costs that are passed to the Back-End Cost Items sheet (which is part of the Activity Cost Module). The section of this sheet labelled 100 is where the user specifies the price obtained for treated water and this information is passed to the FinMod sheet (which is the Financial Module) where this price data is used to calculate revenues from the sale of the treated water.

Costs associated with the water production and disposal wells are found in Tables 4.1-4.50 in the 'Activity_Inputs' worksheet. The user inputs costs for these wells as described in the well cost section of the Activity Cost Module.

At the top of the Water Worksheet (Exhibit 41) is posted information on the Status of Water Management. It is either on or off. This information is pulled in from the Project Management Worksheet and posted in the blue cells.

Exhibit 41 Formation Information & Brine Properties

Status of Water Management						
Are water calculations On or Off (from Project_Management sheet)		Off				
A. Formation information						
Formation	Mount Simon1					
Formation Number	130					
Structure	Dome					
B. Brine Properties						
Input: Ambient reservoir pressure	Pa	14,396,342	psia	2088	MPa	14.4
Input: Ambient reservoir temperature	degC	49.3	degF	121	degK	322
Input: Salinity of water in reservoir	kg/kg	0.0800	mg/L	80,000	ppm	80,000
Density	kg/m3	1,048				
Viscosity	Pa-sec	6.50E-04	cp	0.650		

Formation Information – Part A: Listed here (Exhibit 41) is the formation modeled, the formation number in the geology database, and the structure modeled. This information is pulled in from the Project Management Worksheet and posted in the blue cells.

Brine Properties – Part B: Physical properties of the in-situ brine in the storage reservoir are posted here (Exhibit 41). The input information posted in column D is calculated from data pulled from the geology database (Geol DB Sal) and posted in columns F and H in the blue cells. The temperature, pressure and salinity of the brine in the reservoir are used to calculate the brine density and brine viscosity. The brine density and brine viscosity are calculated with Visual Basic user-defined functions. These Visual Basic functions were adapted from functions written in the Python programming language by Karl Bandilla. The Python program BrineProperties_1_0.py is part of a series of Python programs located at https://code.google.com/p/camelotpy/. This Python program was released as free software under the GNU General Public License as published by the Free Software Foundation, either version 3 of the License, or (at the user's option) any later version of the license.

Calculation of Well Rate of Flow – Part C: Calculation of maximum flow rate for water producing (withdrawal) and water injection (disposal) wells is done here (Exhibit 42). The physical properties of the reservoir and saline water in the reservoir are pulled in from the geology module (Geol Sal) or the geology activity interaction worksheet (Geo-Activity Interaction) and posted in the blue cells.

The equation for calculating the rate of production (Cell D44) or injection (Cell D57) is posted here. For production, the bottom-hole pressure (BHP) of the well is less than the reservoir pressure. For injection, the BHP of the well is greater than the reservoir pressure. A simple assumption here is that the BHP differential for production or injection is the same.

The modeler can enter a value to limit the rate of production (Cell D52) or injection (Cell D60). This will impact the well count for water production or injection wells.

Exhibit 42 Calculation of Well Rate of Flow - Water

C. Calculation of the maximum rate of flow in a single injection or production well		
Calculate maximum rate that water can be produced in a single well based on permeability, thickness and visc		
k = Permeability	Darcies	0.05477
h = Height of Reservoir	ft.	1,000
Pwi = Bottom Hole Pressure for Inj. Well	psia	2392
Pe = Ambient reservoir Pressure at midpoint, Pe	psia	2088
Pwp = Bottom Hole Pressure for Prod. Well	psia	1784
µ = Viscosity of Water at Reservoir Conditions	cP	0.650
re = Effective Radius of Inj. In the Reservoir	ft.	1,640
rw = Radius of Wellbore	ft.	0.33
Rate of Water Production, $Q_{H20\text{-prod-form-max}}$	barrels/day	21,300
$$Q_{H2O} = \frac{7.08kh(P_e - P_w)}{\mu ln(^{r_e}/_{r_w})} = barrels\ per\ day$$		
Calculate flow rate in a single production well based on wellbore flow model		
Max flow rate in prod or inj well from wellbore flow model	barrels/day	10,000
Rate of Water Production, $Q_{H20\text{-prod-max}}$	barrels/day	10,000
	tonnes/year	608,197
Calculate maximum rate that water can be injected in a single well based on permeability, thickness and visco		
Rate of Water Injection, $Q_{H20\text{-inj-form-max}}$	barrels/day	-21,300
Calculate flow rate in a single injection well based on wellbore flow model		
Max flow rate in inj well from wellbore flow model	barrels/day	10,000
Rate of Water Injection, $Q_{H20\text{-inj-max}}$	barrels/day	10,000
	tonnes/year	608,197

Production-Treatment-Disposal Volumes of Water – Part D: Water withdrawn from the storage reservoir will be disposed of or some portion treated, rendered potable and sold for anthropogenic use (Exhibit 43). Also, some modeling has suggested that only a portion of the reservoir saline water needs to be removed to control reservoir pressure and prevent endangerment of the seal. In Cell D66, the modeler can enter the percent of the calculated mass of water to be withdrawn from the storage reservoir. In Cell D67 the modeler can select the percent of withdrawn water that will be treated.

The volume or mass of CO_2 in the storage reservoir establishes the volume or mass of potential water withdrawal. Data for CO_2 is pulled in from the geology database (Geol DB Sal). Volume and mass of CO_2 (Cells D79 to D81) and water (Cells D 84 to D87) is calculated in this worksheet.

The volume of water withdrawn, treated and disposed of is posted under Water Flows in Cells D91 through D107.

Exhibit 43 Production-Treatment-Disposal Volumes of Water

D. Calculation of the water produced, treated, sold and re-injected		
Inputs		
Percent of injected CO2 vol that is produced as water		20.0%
Percent of produced water that is treated		50.0%
Percent of treated water that is sold		80.0%
Duration of production	years	30
Volume of CO2 in reservoir at reservoir temp and press		
M_{CO2} = mass of CO2 injected over operations	tonnes	96,000,000
A = surface area of CO_2 plume	m2	26,628,818
	mi2	10.3
h = height of reservoir	ft	1,000
Ø = porosity		12%
E = storage coefficient		15.28%
p_{CO2} = density of CO_2 at reservoir conditions	kg/m3	645.1
V_{CO2} = volume of CO2 at reservoir temp and press	m3	148,825,288
	barrels	936,085,815
$V_{CO2\text{-}check}$ = vol of CO2 at res temp and press, check	m3	148,825,288
Volume of water produced from reservoir at reservoir temp and press		
V_{H2O} = total volume of H_2O produced	m3	29,765,058
	barrels	187,217,163
p_{H2O} = density of H_2O at reservoir conditions	kg/m3	1,048.1
M_{H2O} = total mass of H_2O produced	tonnes	31,195,846
Water flows		
Water Produced		
Volume produced per day	barrels/day	17,097
Volume produced per year	barrels/year	6,240,572
Volume produced for entire project	barrels	187,217,163
Water to be Treated		
Volume treated per day	barrels/day	8,549
Volume treated per year	barrels/year	3,120,286
Volume treated for entire project	barrels	93,608,582
Treated Water to be Sold		
Volume sold per day	barrels/day	6,839
Volume sold per year	barrels/year	2,496,229
Volume sold for entire project	barrels	74,886,865
Water to be Re-injected		
Volume re-injected per day	barrels/day	10,258
Volume re-injected per year	barrels/year	3,744,343
Volume re-injected for entire project	barrels	112,330,298
Water balance check		
Water reinjected plus water sold (should equal water produced)	barrels	187,217,163

Exhibit 44 Number of Water Wells & Depth of Water Injection

E. Determine number of production and injection wells		
Number of production wells		
Volume produced each day	barrels/day	17,097
Number of Water Production Wells	wells	2
Number of injection wells		
Volume of water injected each day	barrels/day	10,258
Number of Water Disposal Wells	wells	2
F. Specify the depth of water injection wells		
Location of water injection formation above or below stor form	ft	0.0
Depth to top of storage reservoir	ft	4000.0
Depth of water injection or disposal well	ft	4000.0

Number of Production and Injection Wells – Part E: The number of water production wells is (Exhibit 44) determined by the calcualted flow rate for a producing water well taking into account any limitations set by the modeler (Part C). The number of injection wells are determined in similar manner with addition consideration given to the volume of water treated, rendered potable and sold (Part D).

Depth of Water Injection Wells – Part F: For the moment, disposed water is injected at the same depth from which it was produced. Illogical from a reservoir management perspective but this is a cost model, not a reservoir model. The cost of water dispoal is accounted for in the model. We plan to edit the model to allow the modeler to select a depth above or below the storage reservoir for disposal. This will either increase (deeper wells) or reduce (shallower wells) costs as currently modeled.

Cost Associated with Water Production-Treatment-Disposal: Labeling of this particular section follow established convention so that the cost catagories listed here can be tied to the Back-End Cost items sheet.

Table 6.1 Pipeline Costs for Water Production and Injection Wells (Exhibit 45**):** Pipeline network is based on how many miles of pipeline exist per producing well. This pipeline distance provides transportation to surface facilities and to injection well. The number of miles per producing well and injection well is entered in Cell C126. This distance is factored in capital and operating costs also posted in this table. Water production-treatment-disposal is done only during injection operations. The years over which this occurs are set in the Project Management module and posted here in the gray colored cells. For repeat period (Cell E 137), the value of one means capital cost occur in the first year of the time period, or years that this value will be used. For operating costs (Cell E 143), one means that O&M costs occur every year.

Exhibit 45 Cost Associated with Water Production-Treatment-Disposal

6.1 Pipeline Costs for Water Production and Injection Wells				
General inputs for pipeline costs				
Miles Pipeline per Producing and Injection Well	1	mi/well		
Pipeline capital costs				
Mass flow rate in producing water well	0.61	Mtonne/year		
Pipeline fixed capital costs	200,000	$/well		
Pipeline variable capital costs for producing water well	540,000	$/mi		see Surf Eq Cost sheet
Total capital costs for producing well	740,000	$/well		
Mass flow rate in injection water well	0.61	Mtonne/year		
Pipeline variable capital costs for injection water well	540,000	$/mi		see Surf Eq Cost sheet
Total capital costs for producing well	740,000	$/well		
Years When Capital Costs Are Incurred	**Begin Year**	**End Year**	**Repeat Period**	
User Input Selection	0	0		
Years that will be used	7	36	1	
Pipeline O&M costs per well				
Pipeline O&M unit costs	9000	$/mi-yr		see Surf Eq Cost sheet
Pipeline O&M costs per well	9000	$/well-yr		
Years When O&M Costs Are Incurred	**Begin Year**	**End Year**	**Repeat Period**	
User Input Selection	0	0		
Years that will be used	7	36	1	
6.2 Unit Costs for Selected Treatment Options				
		Unit cost in $ per barrel		
Treatment Technology	**Selected Cost**	**Min**	**Max**	**OFF/ON?**
Distillation	$7.40	$6.35	$8.50	OFF
Ion-exchange	$0.13	$0.05	$0.20	OFF
Capacitive deionization	$0.13	$0.05	$0.20	OFF
Reverse osmosis (RO)	$0.40	$0.20	$0.60	ON
Nanofiltration	$0.00	NA	NA	OFF
Cost Ranges for Selected Disposal Options	(Costs posted here may duplicate some costs posted above or in Activity_Inputs. Use of these costs need to be thought through to avoid duplication.)			
		Unit cost in $ per barrel		
Treatment Technology	**Selected Cost**	**Min**	**Max**	**OFF/ON?**
Onsite reinjection	$0.00	$0.84	$1.68	OFF
Offsite reinjection	$0.00	$0.01	$8.00	OFF
Evaporation	$0.00	$0.01	$2.50	OFF
6.3 Unit Costs for water injection				
Water Injection Cost	0.05	$/barrel		
6.4 Unit Costs for water production				
Water Lifting Cost	0.19	$/barrel		
100. Price for treated water that is sold (used in FinMod sheet as supplemental revenue for project)				
User Input Water Price	$0.084	$/barrel		
*See EPA Source for water price	$2/1000 gallons	42 gallons per oil barrel		

Table 6.2 Unit Costs for Selected Treatment & Disposal Options: Five water treatment processes are listed but only four have associated costs. Posted costs cover construction and operation of the facility. Each process has a minimum and maximum cost; the modeler can enter their value in the orange colored cells.

Three disposal options can be selected. These are all turned off. There is potential for some duplication of costs here since well costs are calculated in the Activity Cost module, pipeline costs are calculated in Table 6.1 above and injection costs exclusive of well costs is posted in Table 6.3. This table may be utilized in the future following further modeling and cost data research.

Table 6.3 Unit costs for water injection: Cost per barrel is entered here. This is the cost of pumping the water into the well and formation; the cost of electricity to run the pump.

Table 6.4 Unit cost of water production: Cost per barrel is entered here. This is the cost of lifting the water from the reservoir to the surface. A cost of $0.25 is estimated for lifting and transportation. Transportation costs are posted in Table 6.2; production costs here should reflect lifting. Based on pump efficiency and lifting from a depth of 7,500 feet, a cost of $0.19 is estimated for lifting costs. Using a fixed cost here is a simple method to represent this cost.

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