Final Technical Report

Rigorous Screening Technology for Identifying Suitable CO_2 Storage Sites II

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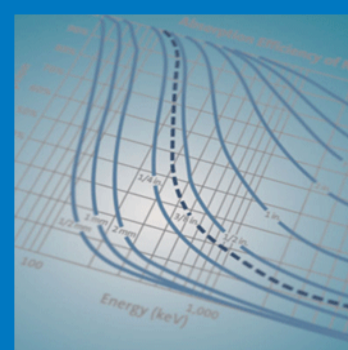

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Abstract

This report serves as the final technical report and users manual for the “Rigorous Screening Technology for Identifying Suitable CO_2 Storage Sites II” SBIR project. Advanced Resources International has developed a screening tool by which users can technically screen, assess the storage capacity and quantify the costs of CO_2 storage in four types of CO_2 storage reservoirs. These include CO_2-enhanced oil recovery reservoirs, depleted oil and gas fields (non-enhanced oil recovery candidates), deep coal seems that are amenable to CO_2-enhanced methane recovery, and saline reservoirs. The screening function assessed whether the reservoir could likely serve as a safe, long-term CO_2 storage reservoir. The storage capacity assessment uses rigorous reservoir simulation models to determine the timing, ultimate storage capacity, and potential for enhanced hydrocarbon recovery. Finally, the economic assessment function determines both the field-level and pipeline (transportation) costs for CO_2 sequestration in a given reservoir.

The screening tool has been peer reviewed at an Electrical Power Research Institute (EPRI) technical meeting in March 2009. A number of useful observations and recommendations emerged from the Workshop on the costs of CO_2 transport and storage that could be readily incorporated into a commercial version of the Screening Tool in a Phase III SBIR.

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1.1 Introduction

The "Screening Tool" which was developed under phase II of the "Rigorous Screening Technology for Identifying Suitable CO_2 Storage Sites" SBIR project has been designed to assist power plant and other stakeholders interested in CO_2 sequestration to assess potential underground CO_2 storage sites. These potential beneficiaries of the "Screening Tool" include the following:

- The major beneficiary would be the public at large, by having greater assurance that sites selected for CO_2 storage would be reliable and safe.
- The large group of electric power plant operators, high volume CO_2 industrial plant managers, and other industrial firms that emit CO_2. These firms would have a rigorous, ready to use set of tools for evaluating the CO_2 storage options available for their plants and thus be able to select the most cost-effective and secure option(s).
- Governmental entities that would be responsible for the permitting, approval and oversight of CO_2 storage sites. These entities would have a more reliable set of protocols and tools by which to approve a proposed CO_2 storage site.

1.2 CO_2 Storage Applications

The "Screening Tool" contains the capacity to evaluate four major types of large-scale underground CO_2 storage options:

CO_2-Enhanced Oil Recovery (CO_2-EOR) in depleted oilfields that are technical candidates for EOR (i.e., they meet the pressure, temperature, and oil gravity standards to technically screen for CO_2-EOR). In addition to CO_2 storage in the reservoir, the model also calculates the volume of oil recovered during EOR, an important parameter for evaluating the costs and provide net revenues from using this CO_2 storage option.

CO_2-Enhanced Coalbed Methane (ECBM) in unmineable coal seams. In addition to CO_2 storage in the coal reservoir, the model also calculates the volume of methane that would be recovered which would lower the costs of using this CO_2 storage option.

CO_2 Storage in Depleted Oil and Gas Fields involving injection of CO_2 into depressurized, depleted natural gas and oilfields (non-EOR candidates). In this case, CO_2 is injected into the reservoir with no expectations of oil or gas recovery (i.e., a pure CO_2 sequestration project).

CO_2 Storage in Saline Reservoirs involving injection of CO_2 into a deep, brine-filled underground formation. In this case, CO_2 is injected into a high salinity reservoir which does not contain oil or natural gas (i.e., a pure CO_2 sequestration project).

The “Screening Tool” methodology assesses the efficacy of CO_2 storage in a given reservoir in three steps:

- First, the reservoir is screened for technical merit as a sequestration target given several critical data such as reservoir depth and the presence of an overlying seal (or “caprock”).

- Second, the quality of the reservoir as a target for CO_2 sequestration is modeled using computer simulation of CO_2 injection. In the cases of EOR and ECBM, the production of hydrocarbons is modeled as well as the breakthrough and production of injected CO_2.

- Finally, the costs and economics of CO_2 transportation and storage are assessed. The “Screening Tool” assesses and tabulates the costs of designing and installing a CO_2 injection facility at the field level with an industry standard cashflow cost model using up to date cost data. The “Screening Tool” model also assesses the potential income from concurrent hydrocarbon production (in the EOR and ECBM cases) and calculates a rate of return for these cases. A pipeline design and cost model is then used to estimate pipeline capital requirements and O&M costs for transportation of CO_2.

Representative data for these four reservoir types from the U.S. DOE's Southeastern Carbon Sequestration Consortium (SECARB) have been incorporated and tested by the Screening Tool. A listing of those reservoirs is included in Attachment A.

The cost and economic models for storing CO_2 with CO_2-EOR ECBM and into depleted oil and gas fields as well as saline formations is provided in Attachment B.

The supporting detail and equations for the CO_2 design and cost model are provided in Attachment C.

Attachment D provides the Users Guide for the site selection "Screening Tool".

2 CO_2 STORAGE SITE "SCREENING TOOL": CO_2 STORAGE

2.1 Reservoir Technical Screening

The first step by the "Screening Tool" is an assessment of the technical ability of a particular target reservoir to serve as a CO_2 storage site. It is essentially a "pass/fail" test based on critical reservoir data. Reservoirs that "fail" this screening are not assessed further by the "Screening Tool". The components of the pass/fail test are described below.

CO_2-Enhanced Oil Recovery (CO_2-EOR) Reservoirs. For depleted oil reservoirs, the "Screening Tool" calculates of the minimum reservoir miscibility pressure and provides a set of quality control checks that enable each oil reservoir to be placed into one of three categories with respect to CO_2-EOR: 1) Miscible CO_2-EOR, 2) Immiscible CO_2-EOR, and 3) None (not technically suitable for CO_2-EOR). Reservoir and oil factors that affect CO_2 miscibility include depth, pressure, temperature, and oil gravity. Reservoirs that screen as amenable miscible or immiscible CO_2-EOR are then assessed by the EOR module in the next step within the "Screening Tool". Those that fail (the third case) are assessed as depleted oil/gas fields and are modeled for "pure" CO_2 storage (without associated hydrocarbon production).

CO_2-Enhanced Coalbed Methane (ECBM). Coal seams are screened based on the depth of the coal seam reservoir. The future potential for mining the coal for energy generation is the primary concern as coal is expected to efficiently adsorb and "lock in" injected CO_2. A conservative minimum depth of 1,000 feet of burial is used as a cutoff in the "Screening Tool".

CO_2 Storage in Depleted Oil and Gas Fields. Depressurized, depleted natural gas and oilfields (non-EOR candidates) are screened based on depth only. It is assumed that existing oil/gas fields have an existing, competent overlying seal that has demonstrated the ability to trap hydrocarbons over millions of years. However, efficient sequestration of CO_2 is generally only considered viable when CO_2 occurs as a dense phase. The “Screening Tool” uses a conservative depth cutoff of a minimum of 800 meters (2,480 ft) to the top of the reservoir.

CO_2 Storage in Saline Aquifers. The feasibility of CO_2 injection into a saline (brine) reservoir is screened based on depth, the presence of an overlying seal, and reservoir water salinity. As in the depleted oil and gas field cases, a minimum depth cutoff of 800 meters (2,480 ft) is imposed. In addition, the presence of a competent seal (or “caprock”) is required for long-term storage. This step assumes that the user has prior geological knowledge and is aware of the regional seals and caprocks. Likewise, a minimum reservoir water salinity of 10,000 ppm is imposed (the maximum US EPA USDW standard). This step also assumes that the user has prior knowledge of the regional groundwater conditions.

2.2 Reservoir Quality Assessment

After the reservoir technical screening step is completed and the reservoir is categorized into one of the four CO_2 storage options described above, the reservoir’s CO_2 sequestration capacity and injection efficiency is calculated. In addition, the concurrent production of hydrocarbons in the cases of EOR and ECBM are assessed. These data allow the user to asses whether the target reservoir is of sufficient capacity and injection quality to merit further study for CO_2 storage. The Reservoir Quality Assessment (RQA) component of the “Screening Tool” performs this function.

The RQA assessment model is programmed in Microsoft Office software and has a graphical user interface (GUI) that allows the user to run reservoir simulations and to change certain key reservoir parameters and re-run the simulations. Annual injection and production (in the cases of ECBM and EOR) volumes can be exported and assessed by the user for all reservoir types. The construction, simulation tools, and major model assumptions are discussed in this section.

Screening Tool Program. The "Screening Tool" was developed in Microsoft (MS) Office environment. The languages used in development of this application are MS Visual Basics (VB) 6.0 and Visual C++. Visual C++ is called in using DLL library. Data is stored in an MS Access database.

The "Screening Tool's" RQA assessment software is divided into two modules. The first processes reservoir data and runs CO_2 storage simulations. The second module performs and displays project economic analysis using the results from the reservoir simulations. There are two kinds of simulators within the setup file of the tool, *Comet3* and *CO_2-Prophet*.

Economic analysis is performed by (COTWO), an MS Excel-based model. The software is capable of exporting simulation and economic results to an Excel spreadsheet for any further analysis by the users. **Figure 1** shows the code's flow chart.

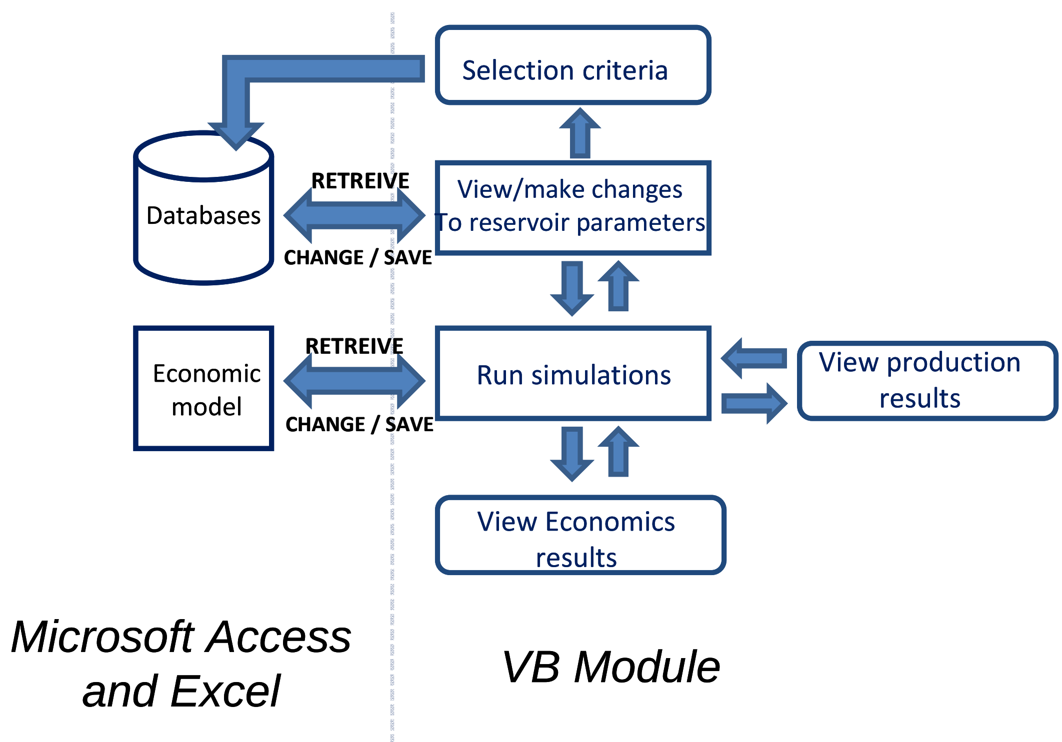

Figure 1: Screening Tool's Programming Flow Chart

Screening Tool Simulators. A description of the two simulators that utilize the "Screening Tool", *COMET3, CO_2-PROPHET*, and the *COTWO* economic model is given below.

1. COMET3 **Reservoir Simulation Model.** *COMET3* is a black-oil based, three-dimensional, three-component, two-phase, simulator for modeling gas and water production and is used to simulation from coalbed methane and gas shale formations, as well as conventional oil and gas reservoirs and saline formations. For modeling gas and water production, *COMET3* is used as a dual-porosity model based on the idealization of fractured media by Warren and Root. Two-phase flow of gas and water occurs in the fracture or cleat system. The fracture system is assumed continuous and provides flow paths to producing wells. Gas flows via diffusion from the discontinuous matrix blocks into the fracture system. The two systems are coupled by use of a desorption isotherm at the matrix-cleat interface.

For the triple-porosity/dual-permeability option, matrix porosity and permeability terms have been added to allow modeling of the release and transport mechanisms for low rank "porous" coal seams by a combination of desorption, diffusion and Darcy flow through a dual permeability network.

The three component gas sorption feature defines the non-linear relationship between free and adsorbed multi-component gas mixtures (methane, nitrogen and carbon dioxide) as a function of methane concentration using extended Langmuir isotherms.

Several unique features of coalbeds which can affect gas producibility are modeled by *COMET3*: 1) pore volume compressibility to account for stress dependent porosity and permeability, 2) coal matrix shrinkage, 3) gas readsorption, 4) enhanced coalbed methane recovery and 5) carbon sequestration. In addition, the effects of gravity and solution gas in water are rigorously considered.

COMET3 utilizes both Cartesian (x-y-z) and radial (r-q-z) coordinate systems for multi-well problems. Single well problems also may be run using either Cartesian or radial geometry. For example, a single vertically fractured well may best be simulated utilizing a symmetry quadrant in Cartesian coordinates. Either finite or infinite conductivity fractures may be simulated, depending on the finite-difference grid and the method of handling well constants. Wells may be horizontal or vertical.

COMET3 has been benchmarked against industry simulators for coal seam gas, conventional gas and black- oil problems (just as was done for the forerunner *COMETPC 3-D*). As such, including *COMET3* in the "Tool Kit" has the following advantages:

- CBM industry-leading reservoir simulation software
- Tracking of CO_2
- Pore volume trapping
- CO_2 solubility
- Multi-phase (oil-gas, oil-water, gas-water)
- Flexible reservoir description
- Flexible well completion options
- Coupled aquifer descriptions for modeling dynamic aquifer flow

Future Modifications. Four additional actions would need to be performed to ensure that *COMET3* is able to address the full range of geologic situations for assessing CO_2 storage in aquifers, oil and gas fields and coals. These are:

- Ability to simulate three-phase flow (CO_2, water and methane/oil)
- Apply miscibility extension to enable more reservoirs to qualify for CO_2-EOR
- Install density inversion to capture long-term CO_2 storage efficiency

- Install relative permeability hysteresis to capture both inflow and outflow from the reservoir's pore space

These four remaining actions would comprise a portion of our work plan for Phase III.

2. CO_2-PROPHET Scoping Model. *CO_2-PROPHET* was developed by the Texaco Exploration and Production Technology Department (EPTD) for the project, "Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" (DOE Contract No. DE-FC22-93BC14960). *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and then performs oil displacement and recovery calculations along the streamlines. (A finite difference routine is used for the oil displacement calculations). Other key features of *CO_2-PROPHET* are also set forth below:

- Areal sweep efficiency in *CO_2-PROPHET* is handled by incorporating streamlines that are a function of well spacing, mobility ratio and reservoir heterogeneity.

- Mixing parameters, as defined by Todd and Longstaff, are used in *CO_2-PROPHET* for simulation of the miscible CO_2 process, particularly CO_2/oil mixing and the viscous fingering of CO_2.

- A series of reservoir patterns, including 5 spot, line drive, and inverted 9 spot, among others, are available in *CO_2-PROPHET*.

- *CO_2-PROPHET* can simulate a variety of recovery processes, including continuous miscible CO_2, WAG miscible CO_2 and immiscible CO_2, as well as waterflooding.

Model Assumptions. Major assumptions for simulating the four cases in the "Screening Tool" are discussed below.

CO_2-Enhanced Oil Recovery Model Assumptions (CO_2-EOR). Six prominent screening criteria are used to identify favorable CO_2-EOR reservoirs. These are:

reservoir depth, oil gravity, reservoir pressure, reservoir temperature, oil composition, and reservoir size. These values are used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard are considered for immiscible CO_2-EOR.

The preliminary screening steps involved selecting the deeper oil reservoirs that have sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5° API is used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Finally, a minimum reservoir size is also applied. Reservoirs within fields containing less than 50 million barrels of oil in place amenable to CO_2-EOR are screened out. Reservoirs excluded from the CO_2-EOR database are included in the Depleted Oil and Gas database and modeled for CO_2 storage only.

CO_2-EOR performance is simulated under "state of the art" technology, which we consider as that which is currently employed in CO_2-Flooding operations by innovative and forward-thinking operators. "State of the Art" technology entails a one hydrocarbon pore volume (HCPV) tapered water-alternating with gas (WAG) flood, with considerable CO_2 recycling to increase oil recovery.

As further discussed below, moderately deep, light oil reservoirs are selected for miscible CO_2-EOR and the shallower light oil and the heavier oil reservoirs are targeted for immiscible CO_2-EOR.

Additional assumptions for the CO_2-EOR model are that field is developed over a 5 year period (20% of the patterns per year) and all produced CO_2 is recycled.

CO_2-Enhanced Coalbed Methane Model Assumptions (ECBM). Similarly to CO_2-EOR, carbon dioxide can be used to extract residual, adsorbed methane in coal seam reservoirs. However, because of the unique nature of coal (gases are stored in the matrix of the coal itself), the introduction of CO_2 often results in significant loss in injectivity due to swelling of the coal matrix (coal stores more of the larger CO_2 molecules per unit of CH_4). This is often a major limitation in the application of the CO2-ECBM process.

For active coal seam reservoirs, initial field pressures are compared to the gas storage adsorption isotherms for the field, yielding a rough estimate of original gas in-place (OGIP). Remaining hydrocarbon gas in-place is then determined by subtracting the OGIP the cumulative gas produced. When translated to a scf/ton of coal value and compared to the adsorption isotherm, this yields an average reservoir pressure for the coal seam reservoir. This is a key step in determining the current in-situ conditions in the reservoir.

Next, the remainder of the reservoir and fluid system data are inserted into the reservoir model. The CO_2 injection design employs a simple 5-spot pattern, which allows the model to be simplified to an injection and production well pair for scale-up to the field. CO_2 injection operations are carried out at an assumed injection pressure gradient of 0.6 psig/ft for a period of ten years.

Depleted Oil and Gas Field Model Assumptions. Depleted oil reservoirs that are not identified as amenable for immiscible or miscible CO_2 flooding and depleted gas reservoirs are candidates for storage of CO_2. As such, these reservoir represent a simple voidage-fill modeling technique. Reservoir pressures, assumed to be at or near abandonment pressures (estimated to be an average reservoir pressure of 250 psig) are allowed to be pressurized to a gradient of 0.6 psig/ft or a maximum injection rate of 25 MMcfd, whichever is the limiting factor. Production wells are simply converted into injection wells on development spacing. While injection operations are carried out for 10 years, in most cases it is possible to fill an enclosed pattern area very rapidly. While capacity and injectivity is rigorously estimated, this short duration suggests that pattern size optimization will be essential in optimizing the economics of CO_2 injection into depleted oil and gas fields.

Saline Reservoir Model Assumptions. CO_2 injection into a deep saline reservoir can be used as an efficient sequestration option as long as storage and flow capacity are sufficient and favorable. For deep saline reservoirs, high porosity and high permeability reservoir rock are ideal, with average porosity of greater than 15%. Reservoir values for these parameters are generally available and a homogeneous case (same horizontal perm and porosity throughout the reservoir) are assumed. Vertical permeability is a key parameter in the CO_2 plume migration and is often unavailable. Hence, an anisotropy of 0.1 (Kv/Kh) is assumed. Initial pressure is assumed at hydrostatic conditions (0.43 psig/ft pressure gradient). A 5 layer reservoir is used with identical reservoir properties in each layer.

To model an infinite acting reservoir and not pressurize the reservoir during the sequestration process, edge aquifers are added to the model. Edge aquifer properties, such as thickness, porosity, permeability, etc, are assumed identical to the main saline reservoir. These edge aquifers allow flow of fluids out of the reservoir, helping counter pressure increase, and are used to simulate injection into an extensive saline reservoir.

The CO_2 injection design employs a simple vertical injector centered in a ~3,000 acre spacing (1 mile by 4.6 miles). CO_2 is injected into the four bottom layers to allow plume migration by buoyancy to the top layer. Residual gas trapping of 15% and capillary effects are included which influence the rate and volume of gas migration. No dip or CO_2 dissolution in water was modeled. Injection operations were carried out at an assumed injection pressure gradient of 0.6 psig/ft with a maximum injection rate of 25MMcfd, for a period of thirty years.

Future Modifications. Several improvements not developed as a part of Phase II in the CO2 injection simulation cases would allow the user greater flexibility in optimizing the model and to examine alternate cases. These include:

- *Modeling alternative geometries (i.e horizontal wells).* The use of horizontal wells for injection would facilitate greater contact with the reservoir, potentially increasing the portion of the reservoir contacted by CO_2 and therefore increasing storage efficiencies. Horizontal wells would also increase potential injection rates into “tight” (i.e. low permeability) reservoirs such as coal seams

- *Modeling alternative well spacing.* Alternative injection pattern spacing may help the user in the timing of CO_2 injection. For example, an increase in injection well spacing within a given reservoir area would likely lower the overall injection rate (fewer wells), however, it may also result in a longer-term injection project at a given location

- *Modeling alternative pattern geometries.* Line drive or other injection pattern geometries may also result in greater reservoir contact, particularly in reservoirs with strong permeability heterogeneities.

- *Modeling alternative well completions.* Depending on the architecture of a particular reservoir, injection into the top of the reservoir or the bottom may result in greater contact with the overall pore space and increase CO_2 storage efficiencies.

The ability to investigate these alternative injection options would comprise a portion of our work plan for Phase III.

2.3 Reservoir Economic Assessment

Introduction. After simulation of CO_2 injection is complete for a reservoir, the user can then assess the projects costs and, where appropriate, economic performance using the Reservoir Economic Assessment (REA) component of the “Screening Tool”. The economic assessment is accomplished using, a field-level cost model of the project, run on an annual cashflow basis, as discussed below.

Field-Level CO_2 Injection Economic Model. The field-level cost model was initially developed by Advanced Resources International for economic assessment of CO_2-EOR opportunities and has been adapted to other CO_2 injection applications. In the “Screening Tool”, the REA component is used for economic assessment of all four of the CO_2 storage options. The REA component is an industry standard cash flow model that can be run on either a pattern or a field-wide basis. The model has been updated continuously as new cost data becomes available.

- The model includes capital costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the CO_2 recycle plant (for CO_2-EOR and ECBM cases); (4) constructing a CO_2 spur-line from the main CO_2 trunkline to the field; and, (5) various miscellaneous costs.

- The cost model also accounts for normal well operation and maintenance costs (O&M), for lifting costs of the produced fluids (in the ECBM and EOR cases), and for costs of capturing, separating and reinjecting the produced CO_2 (for CO_2-EOR and ECBM cases).

The economic component allows the user to determine the timing of a CO_2 demand from any given project and to compare the cost and economics of multiple potential projects. A detailed summary of the structure and assumptions of the cost and economic model is provided in Attachment B. **Figure 2** shows an example output from the Reservoir Economic Assessment model.

Figure 2: CO2 Injection Economic Model (CO2-EOR Case Shown)

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Basin	
Field	
Formation	
Technology Case	
Depth (ft)	5,040
Total OOIP (MMBls)	154.0
Cumulative Recovery (MMbls)	48.4
Primary EUR (MMbls)	49.9
Miscibility	Miscible
API Gravity	34.0
Patterns	76
Existing Injectors Used	55
Convertible Producers Used	0
New Injectors Drilled	0
Existing Producers Used	94
New Producers Drilled	0

Pattern Detail

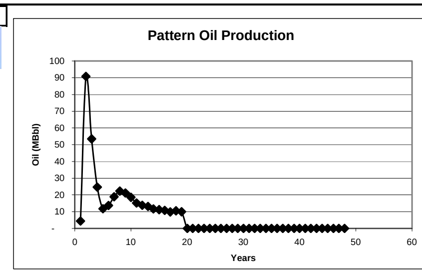
Cum Oil (Mbbl)	386		
Cum H2O (Mbw)	2,505	6.49	Bw/Bbl
Gross CO2 (MMcf)	7,701	19.95	Mcf/Bbl
Purchased CO2 (MMcf)	2,193	5.68	Mcf/Bbl
Recycled CO2 (MMcf)	5,508	14.27	Mcf/Bbl

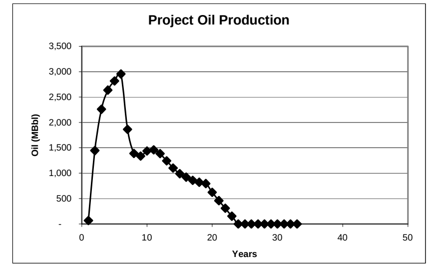
Field Detail

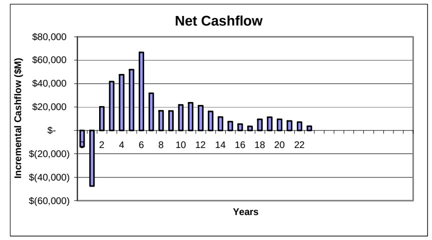
Cum Oil (MMbbl)	29.34	
% OOIP Recovered	19.0%	
Cum H2O (MMbw)	190	
Gross CO2 (MMcf)	585,286	
Purchased CO2 (MMcf)	159,847	
Recycled CO2 (MMcf)	425,439	
Payback Period (per pattern)	2	years
Project Length	23	years

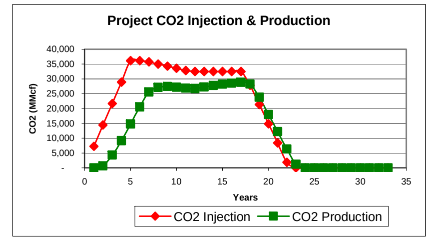
				$/BBl
Total Net Revenue ($M)	$	15,387		
Total Capital Investment ($M)	$	(681)	$	1.76
Total CO2 Cost ($M)	$	(7,140)	$	18.50
Total O&M Costs ($M)	$	(2,402)	$	6.22
	$	(10,222)	$	26.48

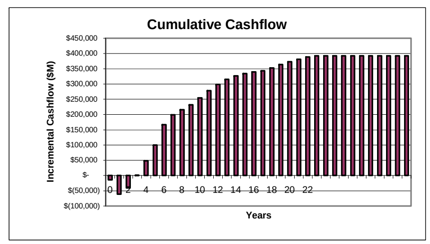
Pattern IRR (BTx)	76.0%
Project IRR (BTx)	51.8%

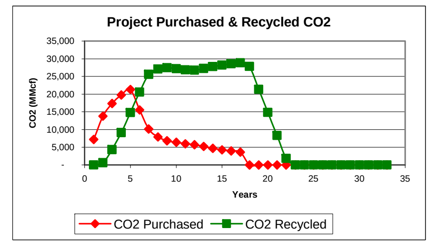


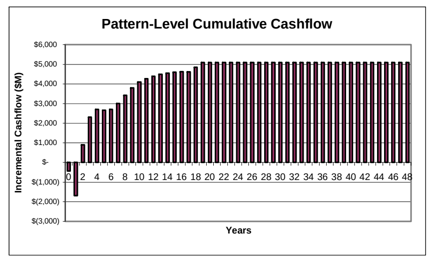












Assumptions:

Economic Case:		
Oil Price	$	50.00
CO2 Purchase Cost	$	2.00
CO2 Recycle Cost	1% of oil price	
Recycling Plant Costs	1 Year before Breakthru	
Well O&M	Prod Wells Only	
Minimum IRR	**15.0%**	

3. CO_2 STORAGE SITE SCREENING TOOL: PIPELINE TRANSPORTATION

3.1 CO_2 Pipeline Design and Cost Model.

ARI's pipeline design and cost model is a tool to help estimate pipeline capital requirements and O&M costs for transportation of CO_2. **Table 1** gives the user-entered, default variables central to the model. In addition to the key variables such as distance and daily CO_2 volume, the model can also incorporate detailed input data on CO_2 pressure and ambient temperature to calculate more optimum pipeline design features that correspond to industry standard pipeline specifications.

Table 1: User-Entered Inputs

Inputs	
CO2 Pipeline Properties	
CO2 mass flow rate tonnes/day	31,058
Intial CO2 Pressure Pinitial (MPa)	1
CO2 Pressure into pipeline	15
CO2 Pressure out of Pipeline	12
Δ Pressure	3
Pipeline Operating Pressure	13.5
Average Distance Between Booster Stations (mi)	100
Include Booster Stations in Pipeline Cost?	Yes
Operating Temperature of Pipeline (C) Range: -1.1 - 82.2 C Non-Inclusive	10
Plant Properties	
Capacity Factor	0.85
Hours/Day of Operation	24
Location Properties	
Distance (mi)	100
Terrain	Grassland
Financial Properties	
Price of Electricity (kwh)	0.05
Capital Recovery Factor	0.15
Inflation Indicies for Mid Year 2009 (Base Year=2005)	
Fabricated Metal Products	117.4
Labor (Construction)	111
Producer Price Index	109

Table 2 shows an example of the output from the CO_2 pipeline design and cost model for a 100 mile pipeline designed to transport, on average 26,400 metric tones per day of CO_2, equal to 9.5 million metric tons per year of capacity. (Converted from metric tons to standard cubic feet, this would be a pipeline with a flow capacity rate of nearly 500 million cubic feet of CO_2 per day, equal to nearly 180 Bcf of CO_2 per year. In addition to pipeline specifications, the model calculates capital and O&M costs on a total, annual and per unit of CO_2 basis. Pipeline capital costs are disaggregated into materials, labor, right of way and miscellaneous costs. O&M costs are displayed for the pipeline and booster stations separately; booster station O&M costs are disaggregated into electricity and capital costs.

Table 2: Example Model Output

Capital Costs	Total	Annualized	Per Tonne CO2	Per Mile
Pipeline				
Materials	$30,752,150	$4,612,823	$0.48	$307,522
Labor	$52,115,814	$7,817,372	$0.81	$521,158
Miscellaneous	$23,201,304	$3,480,196	$0.36	$232,013
Right of Way	$11,505,796	$1,725,869	$0.18	$115,058
Total	$117,575,065	$17,636,260	$1.83	$1,175,751
Booster Stations	$5,826,307	$873,946	$0.09	
Total	$123,401,372	$18,510,206	$1.92	
O&M Costs				
Pipeline		$5,878,753	$0.61	
Booster Stations		$291,315	$0.03	
Booster Electricity		$809,378	$0.08	
Total		$6,979,447	$0.64	
Total Pipeline Costs		$25,489,653	$2.56	

The model employs a series of physics, engineering and economic relationships that apply to CO_2 transportation, the equations that govern these relationships are given in **Attachment B**.

Comparison Against Published Data. To test and calibrate the CO_2 transportation model, we compared the outputs from the model against recently published CO_2 pipeline cost data cost data from Kinder Morgan for a 24 inch pipeline of 100 miles in length, built on flat, dry land, with no urban or river crossings. The results of this comparison are presented in **Table 3**.

Table 3: Kinder Morgan CO_2 Pipeline Cost Comparison

Pipeline Specifications		
Length		100 miles
Diameter		24 inches
Terrain		Flat, dry land
Capital Costs		
($/thousands)	Kinder Morgan	ARI Model
Pipeline	$ 120,500	$ 117,575
Booster Pumps	$ 8,000	$5,826
Total	$ 128,500	$123,401

The model's estimated costs for a pipeline with the above specifications are $123,401,000, within 4% of the published $128,500,000 project price tag from Kinder Morgan. Much of the difference is likely explained by different vintages for these cost estimates; it is not clear in what year's dollars Kinder Morgan's estimates are given.

Future Modifications. The pipeline model would be benefited from an optimization function which would determine the least-cost arrangement of pipeline diameter and booster stations to attain a certain pipeline outlet pressure. This will be a promising area for future research in any future phases of this project.

4 CO_2 STORAGE SITE "SCREENING TOOL": PEER REVIEW

4.1 Introduction

As part of its commitment to "peer review" the CO_2 transportation and storage design and cost model (the CO_2 storage site "Screening Tool"), Advanced Resources worked with the Electric Power Research Institute (EPRI) to conduct the "Workshop on Costs of CO_2 Transport and Storage". The Workshop was held in Palo Alto, California on March 17th and 18th, 2009 and attended by 20 participants, representing EPRI, three universities, four private companies and six of the Regional CO_2 Sequestration Partnerships. **Table 4** contains the Agenda for the Workshop.

The purpose of the Workshop was to gain up-to-date perspectives on: (1) recent experiences and cost information for transporting CO_2 from a power plant gate to a geological storage site; (2) updates on the costs of installing and operating a CO_2 storage facility; (3) updates on the costs of implementing a comprehensive CO_2 storage monitoring system; and, (4) the need for and costs of a reliable remediation plan for addressing CO_2 injection well or other problems associated with CO_2 storage.

The workshop was organized according to six topics, as follows:

- Session #1: Integrated Capture, Transport and Storage Modeling
- Session #2: Cost of Compression and Transportation
- Session #3: Cost of CO_2 Storage Site Selection, Appraisal and Modeling
- Session #4: Cost of Designing, Constructing and Operating CO_2 Storage
- Session #5: Cost of CO_2 Storage Monitoring
- Session #6: Cost of CO_2 Storage Remediation and Mitigation

The highlights from the various presentations and the subsequent extensive participant discussion during the Workshop are provided in this Chapter.

4.2 Workshop Sessions

Summaries of the main themes and information provided in the sixteen formal presentations provided at the Workshop are provided below.

Session #1: Integrated Capture, Transport and Storage Modeling

1.0 Introduction. Mr. Kuuskraa set the stage by stating that the purpose of the first session was to identify and learn more about one important set of "users" of CO_2 transportation and storage cost information - - the national integrated CCS modeling community. This was followed by three presentations.

1.1 Howard Herzog, "Integrated Capture, Transport and Storage Models". Mr. Herzog presented the key components of the MIT Integrated Model which addresses CO_2 capture, CO_2 source-sink matching, CO_2 transport and CO_2 injection and storage. He identified a variety of areas for model improvement including: (1) improved data on CO_2 transport and storage costs; (2) more robust source-sink matching capacity enabling numerous CO_2 sources to link with many sinks; (3) enhancements to the transport module, particularly for CO_2 recompression; and, (4) incorporation of additional cost items (e.g., pore space royalties, right of way and monitoring) to the storage module.

1.2 Edward Rubin, "CO_2 Transport and Storage Models in the IECM Framework". Dr. Rubin presented the Carnegie-Mellon Integrated Environmental Control Model for Carbon Sequestration. This is a free and publically-available desktop/laptop computer model developed by Dr. Rubin and his associates under sponsorship of DOE/NETL. It is available at www.iecm-onlin.com.

1.3 George, Koperna, "Rigorous Screening Technology for Identifying Suitable CO_2 Storage Sites". Mr. Koperna discussed the development of a "tool kit" that would help a power plant operator to: (1) identify the various CO_2 storage opportunities near a defined CO_2 source; (2) quantify the CO_2

injectivity and storage volumes available for one or more CO_2 sources; (3) estimate the development costs of CO_2 transportation, injection and storage; and, (4) calculate the economics of CO_2 injection and storage with offset revenues from enhanced oil recovery (EOR). Mr. Koperna provided an example of a model-based cost calculations for matching 1.5 MM metric tons per year of captured CO_2 with a CO_2 storage sink linked by a 40 mile CO_2 pipeline.

Session #2: Cost of Compression and Transportation

2.0 Introduction. As introduction, Mr. Kuuskraa stated that a main purpose of Session #2 was to set forth methodology for calculating the capital and operating costs of CO_2 transportation systems, including compression. Of particular interest was gaining an understanding of the economies of scale in CO_2 transportation and options for optimizing the costs and performance of this important function. This was followed by two presentations.

2.1 Ken Havens, "Costs of CO_2 Transmission Systems". Mr. Havens began his presentation by noting that industry has constructed over 3,100 miles of mainline CO_2 pipelines, has transported more than 11 Tcf (600 million metric tons) of CO_2 through these pipelines, and has safely operated these pipelines for the past 30+ years. In addition, Mr. Havens discussed the significant environmental and safety procedures used by CO_2 transporters including: (1) 24 hour monitoring of operations using an integrated, real-time Control Center; (2) compliance with industry's "best practices"; and, (3) frequent visual inspection of the pipeline (weekly ground inspection of pumping stations and bi-monthly air inspection of the pipeline route). Finally, Mr. Havens set forth the pipeline specifications for CO_2 and provided a thorough discussion of why these specifications are important.

2.2 Pete Baldwin, "Ramgen Power Systems". Mr. Baldwin introduced the advanced compression system being developed by Ramgen/Dresser-Rand. The key points of his presentation were that:

- Conventional CO_2 compression accounts for approximately 1/3 of the costs of CO_2 capture ($23/metric ton out of a total capture cost of $64/metric ton).
- The Ramgen CO_2 compressor, once commercially available, could cut the compression costs by $10/metric ton and potentially more with fully integrated heat recovery linked to an advanced CCS system.

Session #3: Cost of Site Selection, Appraisal and Modeling

3.0 Introduction. Mr. Koperna set the stage by highlighting the various methods of storing carbon dioxide in the subsurface - - depleted oil and gas reservoirs, coal and shale reservoirs, and deep saline reservoirs. He then introduced the baseline characterization activities that are typically required for minimizing project risk and gaining regulatory acceptance. Finally, he discussed the use of rigorous simulation models for integrating data collected from Monitoring, Verification and Accounting (MVA). This was followed by three in-depth presentations.

3.1 Larry Myer, "Costs of Site Selection and Appraisal": Mr. Myer's thesis was that CO_2 sequestration appraisal wells should inject some (yet undetermined) volume of carbon dioxide and the cost of this activity should be included in the basic appraisal program. This would add costs to the appraisal program, estimated at $5M to $14M, depending on depth, for the West Coast region. Mr. Myer also pointed out that numerous appraisal wells might be required to fully appraise a site for sequestration.

In addition to using numerous wells and CO_2 injection for site appraisal, he estimated that the cost expectations for initial site screening studies were on the order of $150K, that the initial geologic model and simulation costs would be approximately $500K, using existing information from wells and seismic.

3.2 Neeraj Gupta, "Site Selection, Appraisal, Modeling Costs for Geologic Storage of CO_2 – Midwestern U.S. Experience": Dr. Gupta provided a summary of Batelle's site appraisal work for the Midwest Regional Carbon

Sequestration Partnership (MRCSP), which included well costs of $1M to $3M, including casing and logging plus geologic characterization, modeling and permitting costs of $150K to $550K. Seismic sampling (2-D) was expected to be $15K to $20K per linear mile.

With regard to large scale tests, he reported $7M had been spent for site characterization at the Mountaineer site (in 2003-2005) and $8M had been spent for geological characterization at the FutureGen site. One of the key points made during his presentation was the difficulty in providing reliable cost estimates in a volatile commodity price market for steel and oilfield services.

3.3 Brian McPherson, "CO_2 Plume Modeling for Appraising and Designing CCS Sites: 'Lessons Learned' and Implications for Commercial CCS Costs": Mr. McPherson talked about the geological and reservoir modeling efforts being conducted by the Southwest Regional CO_2 Sequestration Partnership. Four field examples were presented representative of sites with little as well as with significant amounts of geological data. In sites with sparse data (deep saline formations), the existing investment for site characterization is on the order of two to three million dollars, while the characterization investment for sites with large volumes of data (potential CO_2-EOR sites), the costs are on the order of hundreds of thousands of dollars. These costs include gathering data from wells (logs, core) and seismic. Time-lapse seismic at a cost of $1M per incremental survey was recommended to confirm plume movement and for calibration of simulation models. To date, specialty data sampling, whether it be time-lapse vertical seismic profiling, tilt meters or elevation surveys cost on the order of $400K to $500K. Based on recent experiences, seismic methods are providing the more reliable data.

To properly estimate the costs associated with site characterization, appraisal and modeling, several common themes emerged from the Workshop discussion:

1. Since geologic characterization protocols, material and service costs vary regionally, cost estimates for CCS should be performed on a regional basis.
2. Seismic methods, while costly and not universally applicable, appear to be the most reliable method of tracking the injection plume. Additional research is needed to either reduce costs, or find less costly techniques.
3. The need to inject fluids, preferably CO_2 into the pilot site assessment well to ascertain injectivity and in-reservoir flow performance, is essential for understanding how the larger-scale CCS project will perform.

Session #4: Cost of Designing, Constructing and Operating CO_2 Storage

4.0 Introduction: Mr. Koperna introduced Session #4 by showing slides from the Southeast Carbon Sequestration Partnership's (SECARB) Plant Daniel test site, which highlighted the final well design, the construction of the storage site and the operation of the small-scale CO_2 test. This was followed by three presentations.

4.1 Scott Frailey, "Cost of Designing, Constructing and Operating CO_2 Storage": Using the Midwest Geological Sequestration Consortium's Phase III, large-scale injection pilot as a basis, Mr. Frailey discussed the recent costs associated with the design, construction and operation of the single-well CO_2 storage site. The well design was a large diameter (12.5 inches), deep saline injection well (8,000 feet) capable of injecting 1,000 tonnes per day of CO_2, which may be a good proxy for commercial development. The permitting and well design costs were $200K.

Construction costs, including the site and infrastructure, were anticipated to be $4.6M and $7.6M, depending on well diameter. Mr. Frailey further stated that the larger diameter well might cost $5.7M once research-related items were deleted. Equipping and operating of the above wells (including wellheads, injection tubing and equipment, monitoring, cased hole MVA and personnel) would cost 10% of the construction costs, estimated at $340K for the 7 inch well and $700K for the 9-5/8 inch well. Annual operating expenses were estimated to be $20K per well/per year.

4.2 John Harju, "EOR, CO_2 Sequestration, and Carbon Management": Representing the Plains CO_2 Reduction Partnership, Mr. Harju provided a review of combining CO_2 storage with enhanced oil recovery. He illustrated the costs for pipeline transportation in terms of dollars per inch-mile, and addressed issues with conversion of existing natural gas pipelines to CO_2 delivery lines. Further, he broke out the expenses of CO_2-EOR, highlighting electricity for compression as the largest single expense.

Mr. Harju then discussed the Zama sour-gas injection pilot as a case study for the numerous Canadian pinnacle reefs. He pointed out that expanding the monitoring plans for a more commercial entity would only increase the overall capital expenditure from 10% to 13% of total costs. To close, Mr. Harju set forth a thought-provoking site permitting and monitoring procedure. This process classified potential sequestration sites into Tiers and then laid out monitoring protocols based on the Tier system.

4.3 Ian Duncan, "Cost of Monitoring a Large Scale Injection – what we have learned from SECARB Phase II and III, Cranfield, MS": Mr. Duncan presented the ongoing efforts for SECARB's Cranfield test site, laying the basis for cost developed at the end of his presentation. He also discussed the need for a mature and "parsimonious" (frugal) MVA strategy for large scale operations.

Costs were developed based on 10 million (MM) tons per year of CO_2 injected into a Tuscaloosa formation:

Stage 1 - Site Selection:	$1.0MM
Stage 2 – Site Characterization:	$5MM to $6MM
Stage 3 – Storage Field Development:	$20MM to $45 MM
Stage 4 – Monitoring and Closure:	$20MM to $25MM
Total:	$46MM to $77MM

Session #5: Cost of CO_2 Storage Monitoring

5.0 Introduction. Mr. Kuuskraa introduced this Workshop session by noting monitoring provides a most valuable acceptance and risk mitigation function. While calling for rigorous monitoring of CO_2 storage, he noted that it needs to be efficient and “fit for purpose”.

5.1 Richard Esposito, “Perspectives on Power Company Needs for Monitoring”. Mr. Esposito noted that effective monitoring and demonstration of secure storage will resolve many of the risk and acceptance issues related to CCS, helping facilitate insurability, financing, regulatory compliance and calibration of reservoir models. However, the comprehensive monitoring system installed at a CO_2 storage site must balance costs with performance and avoid the use of high cost, low-value monitoring options.

5.2 Sally Benson, “Performance Requirements and Life Cycle Costs for Monitoring Geologic Storage of CO_2”. Dr. Benson provided an extensive set of presentations on monitoring geologic storage of CO_2 including topics such as: (1) monitoring protocols; (2) life-cycle CO_2 monitoring costs; (3) use of pressure monitoring for detecting CO_2 leakage; and (4) an alternative strategy for CO_2 inventory verification and carbon credits.

Dr. Benson updated her highly quoted paper on the costs of monitoring prepared in 2004. The present day (2009) enhanced CO_2 monitoring costs are now estimated at \$0.38 to \$0.52 per metric ton for three sample saline CO_2 storage formations up from \$0.28 to \$0.31 per metric ton for year 2004 costs. The primary reason for the increase in costs is due to increased costs for the seismic survey and the incorporation of above zone pressure monitoring.

5.3 Tom Daley, “Seismic Monitoring of Carbon Sequestration”. Mr. Daley introduced his presentation by comparing the level of detail and areal coverage provided by the various geophysical methods ranging from reservoir core samples to use of InSAR satellite imagery. After the introductory materials, Mr. Daley provided examples of the resolution and costs of using surface and borehole seismic for tracking the CO_2 plume. Of particular emphasis was the need to first establish a baseline and then the repeat application of seismic surveys (popularly called 4D seismic) to monitor the areal movement and, where possible, the vertical distribution of the injected CO_2. Based on this discussion by the Workshop participants, a fruitful topic for further investigation and contribution would be identifying areas and geologic settings where traditional surface seismic would be ineffective, thus requiring the use of other large-scale CO_2 monitoring methods.

Session #6: Costs of CO_2 Mitigation/Remediation

6.0 Introduction. Mr. Koperna introduced the need for establishing a remediation plan that would address wellbore leakage (abandoned or operating wells), geologic leaks (faults, fractures, poor seals, or spill points) and operational leaks (over injecting, over pressuring).

6.1 Vello Kuuskraa, "Lessons Learned from the Gas Storage Industry ": Mr. Kuuskraa set the stage for discussing the history of the natural gas storage industry, with more than ninety years of gas injection and extraction experience. Key lessons were:

1. The operation of underground natural gas storage has been extremely safe.
2. Improperly selected storage sites with caprock problems have led to loss of stored gas into a separate geologic formation.
3. Extensive use of monitoring wells is used to detect loss of gas from the storage structure.
4. Improper well plugging, defective casing and poor placement can lead to gas leakage but can be quickly remediated at low costs.

5. It may be possible to improve the injectivity of lower permeability storage sites with “new and novel” well stimulation technologies.

6.2 Don Winslow, “Escape of CO_2 and Natural Gas From Subsurface Reservoirs”: Mr. Winslow provided an industry perspective of how leaks are mitigated. Case examples were provided from injection and production (natural, CO_2 and sour gas) field operations and included well blowouts and injection well failures.

Leak detection methodologies were discussed as well as mitigation strategies to mitigate leaks in injection and non-injection wells (production, monitoring and abandoned wells). To close, Mr. Winslow provided remediation costs for locating CO_2 leaks, well plugging, well remediation and caprock leakage.

4.3 Recommendations For Improving Cost Of CO_2 Transportation And Storage Cost Models

A number of useful observations and recommendations emerged from the Workshop on Costs of CO_2 Transport and Storage, as follows:

1. Develop and Distribute a “Guidelines Manual and Simplified Model” for Estimating the Costs of CO_2 Storage.

The discussion by the workshop participants suggested that it would be valuable to develop and distribute a “guidelines manual and simplified model” for use in making preliminary estimates of the costs of CO_2 transportation and storage.

This manual/model would be updated periodically to reflect the recent cost experience in the industry and would include regionally-specific information on the following topics, among others:

- Estimating the optimum CO_2 pipeline diameter for alternative volumes of CO_2 transportation capacity.

- Estimating the capital costs for installing CO_2 pipelines of different capacity in a variety of geographic and population density settings.

- Calculating the annual costs for operating and maintaining CO_2 pipelines with differing transportation capacity.

- Establishing the costs of drilling and completing CO_2 injection wells at different depths.

- Estimating the costs of drilling CO_2 observation /monitoring wells at different depths.

- Estimating the costs of collecting geologic and reservoir data from cores, logs and other sources.

- Estimating the costs of conducting seismic, both surface and borehole.

- Evaluating the costs of installing and operating alternative monitoring systems.

- Planning for the costs of remediating problem wells.

2. Develop Procedures and Information for Incorporating the Full Costs of CO_2 Storage Site Selection and Appraisal.

The discussion by the workshop participants suggested that more complete identification of the key site selection and appraisal steps and costs would provide a more comprehensive base for estimating the full costs of CO_2 storage. This would include costs for:

- Comprehensive site appraisal, including small-scale injection of CO_2 (or other fluids),

- Purchase of surface and sub-surface rights for storing CO_2,

- Purchase of both short-term and long-term liability insurance,

- Purchase of “right-of-way” for pipeline transportation, and

- Contingency costs for site appraisals leading to site rejection.

Incorporation of the full set of site appraisal and acquisition costs would provide a more reliable set of data by which to compare CO_2 storage options and mitigation choices.

3. Conduct In Depth Appraisals of Gas Storage Operations to Establish Probabilities of Failure Incidents for Risk Assessments.

The workshop participants noted that little reliable information exists on the likelihood of minor or major CO_2 leakage and wellbore failure incidents. Similarly, little first-hand information exists on the costs of remediating these incidents, limiting the reliability of current risk assessment models and methodologies.

One source for this failure incident probability and risk data would be from documenting the experiences of the natural gas storage industry. Another source would be from documenting the experiences of the natural CO_2 production and transportation industry.

4. Sponsor Case Studies of Installing and Operating Current CO_2 Transportation Systems to Promote Public Acceptance.

The workshop participants noted that the existing CO_2 pipeline system, with over 3,000 miles of mainline pipe and over 30 years of operational experience, provides excellent examples and guidelines for safe operations of large-scale CO_2 transportation systems.

A series of case studies examining three of these CO_2 pipeline systems, such as the recently being installed Green Pipeline of Denbury, the cross-border CO_2 pipeline from Northern Great Plains (North Dakota) to the Weyburn oil field in Canada, and the extensive CO_2 pipeline network operated by Kinder-Morgan, would provide a valuable reference document plus information to the public and regulatory community on the safety and practicality of CO_2 transportation.

5. Sponsor Storage Design and Reservoir Modeling Studies for Maximizing the Utilization of Theoretically Available Storage Capacity of Saline Formations.

The current CO_2 storage capacity guidelines, drawn from experience with traditional geological storage facility designs, assume that only 1% to 4% of the theoretical storage capacity in a saline formation can be accessed and used.

Considerable efficiencies, as well as opportunities for concentrating the CO_2 plume could be gained by examining and testing alternative storage designs and well placements, including the use of horizontal rather than vertical CO_2 injection wells. The objective of these studies would be to increase the useable storage capacity in saline formations to 10% to 20% of their theoretical capacity.

6. Sponsor CO_2 Well Completion Designs and Reservoir Modeling Studies for Enhancing the Injectivity of CO_2 into Saline Formations.

Many of the potential CO_2 storage reservoirs, particularly reservoirs in the Appalachian Basin, are low in permeability thus limiting the daily and annual volume of CO_2 that can be injected. This leads to the need to drill many more CO_2 injection wells and possible pressure interference which also reduces CO_2 injectivity.

One approach to addressing this issue would be to examine the practicality of using well stimulations, as has been tested by the gas storage industry, to improve CO_2 injectivity. Another approach would be to examine the use of horizontal wells for improved CO_2 injectivity. A third step would be to evaluate alternative CO_2 injection well spacings that would preclude early pressure interference.

Table 4: Workshop Agenda

Workshop Agenda EPRI Workshop on Costs of CO_2 Transport and Storage March 17-18, 2009 Stanford Park Hotel 100 El Camino Real, Menlo Park, CA 94025		
Tuesday, March 17, 2009 (Day 1)		
8:00AM-8:30AM	Continental Breakfast	
8:30AM – 8:45 AM	Welcome, Introductions and Agenda	EPRI/ARI
8:45AM – 10:15AM	Session #1: Integrated Capture, Transport and Storage Modeling	
	Introduction (5 min)	Kuuskraa/ARI
	Integrated Modeling #1 (25 min)	Herzog
	Integrated Modeling #2 (25 min)	Rubin
	Power Plant Decision-Making Modeling #3 (10 min)	Koperna
	Discussion (25 min)	Herzog
10:15AM – 10:30AM	Break	
10:30AM – 12:00PM	Session #2: Cost of Compression and Transportation	
	Introduction (5 min)	Kuuskraa/ARI
	CO2 Transportation Systems (45 min)	Havens/Kinder-Morgan
	Advanced Compression (15 min)	Baldwin/RAMGEN
	Discussion (25 min)	Havens
12:00PM – 1:00PM	Lunch	
1:00PM-2:45M	Session #3: Costs of Site Selection, Appraisal and Modeling	
	Introduction (5 min)	Koperna/ARI
	Site Selection and Appraisal	
	WESTCARB Case Study (25 min)	Myer
	MRCSP Case Study (25 min)	Gupta
	SWP Case Study (25 min)	McPherson
	Discussion (25 min)	Myer
2:45PM-3:00PM	Break	
3:00PM-4:45PM	Session #4: Cost of Designing, Constructing and Operating CO2 Storage	
	Introduction (5 min)	Koperna/ARI
	MGSC Case Study (25 min)	Frailey
	PCOR Case Study (25 min)	Harju
	SECARB Case Study (25 min)	Duncan/Havorka
	Discussion (25 min)	Harju
	Adjourn	
5:00PM-6:00PM	Cocktails and snacks	

Table 4: Workshop Agenda

Workshop Agenda EPRI Workshop on Costs of CO_2 Transport and Storage March 17-18, 2009 Stanford Park Hotel 100 El Camino Real, Menlo Park, CA 94025		
Wednesday, March 18, 2009 (Day 2)		
8:00AM-8:30AM	Continental Breakfast	
8:30AM – 10:00 AM	Session #5: Cost of Monitoring	
	Introduction (5 min)	Kuuskraa/ARI
	Perspectives on Power Company Needs for Monitoring (15 min)	Esposito
	Cost of Monitoring for Full-Scale CO2 Storage (25 min)	Benson
	Perspective on Seismic Monitoring (20 min)	Dailey
	Discussion (25 min)	Benson
10:00AM – 10:15AM	Break	
10:15AM – 11:15AM	Session #6: Costs of CO2 Mitigation/Remediation	
	Introduction (5 min)	Koperna/ARI
	Lessons Learned from the Gas Storage Industry (20 min)	Kuuskraa/ARI
	Industry Practices for Remediating Well Leakage Problems (20 min)	Winslow/Chevron
	Discussion (15 min)	Koperna/ARI
11:15-12:00PM	Closing Session	EPRI
	Open Discussion (45 min)	Rhudy/Trautz EPRI
	Adjourn	

ATTACHMENT A:
SCREENING TOOL RESERVOIR DATA

Representative data for the four reservoir types (CO_2-EOR, ECBM, depleted oil/gas, and saline reservoir) have been integrated into the Screening “Tool”. A listing of the included reservoirs is provided in this attachment.

1) CO_2-Enhanced Oil Recovery (CO_2-EOR) 159 CO_2-EOR candidate oil reservoirs are included with the screening tool. They represent the majority of the large, CO_2-EOR technically screened onshore reservoirs within Alabama, Arkansas, Florida, Louisiana, and Mississippi. These data were taken from ARI’s large oilfield database used to develop the “Basin-Oriented CO_2-EOR Assessments Examine Strategies for Increasing Domestic Oil Production” series for DOE. A listing of the reservoirs is provided below.

State	Field	Reservoir
AL	CITRONELLE	RODESSA
AL	LITTLE ESCAMBIA CREEK	SMACKOVER
AL	NORTH FRISCO CITY	FRISCO CITY
AL	WOMACK HILL	SMACKOVER
AR	FOUKE	PALUXY - TUSCALOOSA
AR	MAGNOLIA	SMACKOVER
AR	MIDWAY	SMACKOVER
AR	SCHULER	COTTON VALLEY
AR	SCHULER	JONES
AR	WESSON	HOGG
FL	BLACKJACK CREEK	SMACKOVER
FL	JAY	SMACKOVER
FL	RACOON POINT	SUNNILAND
FL	SUNNILAND	SUNNILAND
FL	WEST FELDA	ROBERTS
LA	ANSE LA BUTTE	MIOCENE AMOCO OPERATED ONLY
LA	AVERY ISLAND	MEDIUM
LA	BARATARIA	24_RESERVOIRS
LA	BATEMAN LAKE	10400 GRABEN
LA	BAY ST ELAINE	13600 - FT SAND, SEG C & C-1
LA	BAY ST ELAINE	DEEP
LA	BAYOU SALE	SALE DEEP
LA	BLACK BAYOU	FRIO SAND, RESERVOIR A
LA	BLACK BAYOU	RESERVOIR O T SAND
LA	BLACK BAYOU	T2_SAND RESERVOIR F
LA	BLACK BAYOU	T-SAND
LA	BONNET-CARRE	OPERCULINOIDES
LA	BOSCO	DISCORBIS
LA	BULLY CAMP	TEXTULARLA, RL
LA	CAILLOU ISLAND	53_C RA SU
LA	CAILLOU ISLAND	9400 IT SAND, RBBIC
LA	CAILLOU ISLAND	DEEP
LA	CAILLOU ISLAND	UPPER 8000 RA SU

LA	CECELIA	FRIO
LA	CHANDELEUR SOUND BLOCK 0025	BB_RA SAND
LA	CLOVELLY	50_SAND, FAULT BLOCK VII
LA	CLOVELLY	FAULT BLOCK IV NO 50 SAND
LA	COTE BLANCHE BAY WEST	MEDIUM
LA	COTE BLANCHE BAY WEST	WEST
LA	COTE BLANCHE ISLAND	20_SAND
LA	COTE BLANCHE ISLAND	DEEP
LA	COTTON VALLEY	BODCAW
LA	CUT OFF	45_RESERVOIRS
LA	DELHI	DELHI ALL
LA	DELTA DUCK CLUB	A SEG LOWER 6300 SAND
LA	DELTA DUCK CLUB	B SEG LOWER 6300 SAND
LA	DOG LAKE	DGL CC RU SU (REVISION)
LA	EGAN	CAMERINA
LA	EGAN	HAYES
LA	ERATH	8700
LA	ERATH	7300 SAND
LA	FORDOCHE	W12 RA
LA	GARDEN ISLAND BAY	177 RESERVOIR A
LA	GARDEN ISLAND BAY	MEDIUM
LA	GARDEN ISLAND BAY	SHALLOW
LA	GOOD HOPE	P-RESEROIVR NO 45900
LA	GOOD HOPE	S-RESERVOIR NO. 54900
LA	GRAND BAY	10B SAND, FAULT BLOCK A-1
LA	GRAND BAY	21_SAND, FAULT BLOCK B
LA	GRAND BAY	2MEDIUM
LA	GRAND BAY	MEDIUM
LA	GRAND LAKE	873
LA	GUEYDAN	ALLIANCE SAND
LA	HACKBERRY WEST	2MEDIUM
LA	HACKBERRY WEST	CAMERINA C SAND - FB 5
LA	HACKBERRY WEST	MEDIUM
LA	HACKBERRY WEST	OLIGOCENE AMOCO OPERATED ONLY
LA	HAYNESVILLE	PETTIT
LA	HAYNESVILLE	TOKIO
LA	HAYNESVILLE EAST	BIRDSONG - OWENS
LA	HAYNESVILLE EAST	EAST PETTIT
LA	LAFITTE	LOWER ST. DENNIS SAND, SEG H
LA	LAKE BARRE	LB_LM2 SU
LA	LAKE BARRE	LM1 LB SU
LA	LAKE BARRE	UNIT B UPPER M-1 SAND
LA	LAKE BARRE	UPPER MS RESERVOIR D
LA	LAKE HATCH	9850 SAND
LA	LAKE PALOURDE EAST	
LA	LAKE PELTO	PELTO DEEP
LA	LAKE WASHINGTON	21_RESERVOIR A
LA	LAKE WASHINGTON	DEEP
LA	LEEVILLE	95_SAND, SEG B
LA	LEEVILLE	96_SAND, SEG B
LA	LISBON	PET LIME
LA	LITTLE LAKE	E-4 SAND, RES A
LA	MAIN PASS BLOCK 0035	90_CHANNEL G2

LA	MAIN PASS BLOCK 0035	G2_RESERVOIR A SAND UNIT
LA	MANILA VILLAGE	29_SAND
LA	NORTH SHONGALOO - RED ROCK	AAA
LA	OLD LISBON	PETTIT LIME
LA	PARADIS	DEEP
LA	PARADIS	LOWER 9000 FT SAND RM
LA	PARADIS	MAIN PAY SAND, SET T
LA	PARADIS	PARADIS ZONE, SEG A-B
LA	PHOENIX LAKE	BROWN A-1
LA	PORT BARRE	FUTRAL SAND, RESERVOIR A
LA	QUARANTINE BAY	3 SAND, RESERVOIR B
LA	QUARANTINE BAY	5 SAND, (REF)
LA	QUARANTINE BAY	8 SAND, RESERVOIR B
LA	QUARANTINE BAY	9A_SAND, FAULT BLOCK C
LA	QUARANTINE BAY	MEDIUM
LA	RODESSA	RODESSA ALL
LA	ROMERE PASS	9700
LA	ROMERE PASS	28_RESERVOIRS
LA	SATURDAY ISLAND	11 RESERVOIRS
LA	SATURDAY ISLAND	
LA	SECTION 28	2ND HACKBERRY, RESERVOIR D
LA	SOUTHEAST PASS	J-5 SAND RA
LA	SOUTHEAST PASS	L RESERVOIR C
LA	SWEET LAKE	AVG 30 SANDS
LA	SWEET LAKE	
LA	TEPETATE	ORTEGO A
LA	TEPETATE WEST	MILLER
LA	VALENTINE	N SAND RESERVOIR A
LA	VALENTINE	VAL N RC SU
LA	VENICE	B-13 SAND
LA	VENICE	B-30 SAND
LA	VENICE	B-6 SAND
LA	VENICE	B-7 SAND
LA	VENICE	M-24 SAND
LA	VILLE PLATTE	MIDDLE COCKFIELD RA
LA	VILLE PLATTE	RD_BASSAL COCKFIELD
LA	VILLE PLATTE	RI_BASAL COCKFIELD
LA	WEEKS ISLAND	DEEP
LA	WEEKS ISLAND	R-SAND RESERVOIR A
LA	WEEKS ISLAND	S-SAND RESERVOIR A
LA	WELSH	CAMERINA
LA	WEST BAY	11A SAND (RESERVOIR A)
LA	WEST BAY	11B SAND FAULT BLOCK B
LA	WEST BAY	6B_RESERVOIR G
LA	WEST BAY	8A_SAND FAULT BLOCK A
LA	WEST BAY	8AL SAND
LA	WEST BAY	MEDIUM
LA	WEST BAY	PROPOSED WB68 (RG) SAND UNIT
LA	WEST BAY	WB1 (FBA) SU
LA	WEST BAY	X-11 (RESERVOIR A)
LA	WEST BAY	X-9A SAND (RESERVOIR A)
LA	WEST DELTA BLOCK 83	10100 C SAND
LA	WHITE CASTLE	O1_RF SU

LA	WHITE LAKE EAST	4-SAND
LA	WHITE LAKE WEST	AMPH B
LA	WHITE LAKE WEST	BIG 3-2, RE, RC
MS	BAY SPRINGS	CVL LOWER COTTON VALLEY
MS	CRANFIELD	LOWER TUSCALOOSA
MS	EUCUTTA EAST	E_EUTAW
MS	HEIDELBERG, EAST	E_CHRISTMAS
MS	HEIDELBERG, EAST	E_EUTAW
MS	HEIDELBERG, EAST	UPPER TUSCALOOSA
MS	HEIDELBERG, WEST	W_CHRISTMAS
MS	LITTLE CREEK	LOWER TUSCALOOSA
MS	MALLALIEU, WEST	LOWER TUSCALOOSA WMU C
MS	MCCOMB	LOWER TUSCALOOSA B
MS	PACHUTA CREEK, EAST	ESOPU RES.
MS	PICKENS	EUTAW
MS	QUITMAN BAYOU	4600 WILCOX
MS	SOSO	BAILEY
MS	TINSLEY	SELMA-EUTAW-TUSCALOOSA
MS	TINSLEY	W_WOODRUFF SAND WEST SEGMENT
MS	YELLOW CREEK, WEST	EUTAW

2) CO_2-Enhanced Coalbed Methane (ECBM) 16 candidate ECBM reservoirs CO_2-EOR are included with the screening tool. They are all located in the Black Warrior Basin in Alabama and represent the most significant current coalbed methane producing region in SECARB. Reservoir data were provided by the Geological Survey of Alabama. For more information, see Geologic Screening Criteria for Sequestration of CO_2 in Coal: Quantifying Potential of the Black Warrior Coalbed Methane Fairway, Alabama (DE-FC26-00NT40927). A listing of the reservoirs is provided below.

State	Field	Reservoir
AL	BIG SANDY CREEK	POTTSVILLE COAL INTERVAL
AL	BLUE CREEK	POTTSVILLE COAL INTERVAL
AL	BROOKWOOD	POTTSVILLE COAL INTERVAL
AL	CEDAR COVE	POTTSVILLE COAL INTERVAL
AL	DEERLICK CREEK	POTTSVILLE COAL INTERVAL
AL	HOLT	POTTSVILLE COAL INTERVAL
AL	LITTLE BUCK CREEK	POTTSVILLE COAL INTERVAL
AL	LITTLE SANDY CREEK	POTTSVILLE COAL INTERVAL
AL	MOUNDVILLE	POTTSVILLE COAL INTERVAL
AL	OAK GROVE	POTTSVILLE COAL INTERVAL
AL	PETERSON	POTTSVILLE COAL INTERVAL
AL	ROBINSON'S BEND	POTTSVILLE COAL INTERVAL
AL	SHORT CREEK	POTTSVILLE COAL INTERVAL
AL	TAYLOR CREEK	POTTSVILLE COAL INTERVAL
AL	THORNTON CREEK	POTTSVILLE COAL INTERVAL
AL	WHITE OAK CREEK	POTTSVILLE COAL INTERVAL

3) CO_2 Storage in Depleted Oil and Gas Fields. 200 depleted oil and gas fields are included in the screening tool. They represent the majority of the large, depleted onshore oil (non-CO_2-EOR candidate) and gas reservoirs within Alabama, Arkansas, Florida, Louisiana, and Mississippi. These data were taken from a database that was assembled by ARI for its work in assessing the CO_2 storage capacity of depleted oil and gas reservoirs for the SECARB consortium. A listing of the reservoirs is provided below.

State	Field	Reservoir
AL	BEAVERTON	CARTER NE
AL	BEAVERTON	CARTER SE
AL	BEAVERTON	LEWIS
AL	BETHEL CHURCH	CARTER
AL	BIG ESCAMBIA CREEK	SMACKOVER
AL	BLOOMING GROVE	CARTER
AL	BLOWHORN CREEK	CARTER
AL	CHATOM	SMACKOVER
AL	CHUNCHULA	SMACKOVER
AL	COPELAND	SMACKOVER
AL	CORINTH	CARTER
AL	DAVIS CHAPEL	CARTER
AL	DAVIS CHAPEL NE	CARTER
AL	DETROIT EAST	CARTER
AL	FANNY CHURCH	SMACKOVER
AL	FAYETTE WEST	CARTER
AL	FLOMATON	NORPHLET
AL	HATTERS POND	NORPHLET
AL	HATTERS POND	SMACKOVER
AL	HATTERS POND	SMACKOVER - NORPHLET
AL	KENNEDY	CARTER
AL	MCCRACKEN MOUNTAIN	CARTER
AL	MCCRACKEN MOUNTAIN	LEWIS
AL	MCGEE LAKE	CARTER
AL	MUSGROVE CREEK	CARTER
AR	ATLANTA	SMACKOVER
AR	CECIL	ATOKA
AR	CECIL	HALE
AR	CECIL	MORRIS
AR	CLARKSVILLE	ATOKA
AR	CLARKSVILLE	HALE
AR	DORCHEAT-MACEDONIA	COTTON VALLEY
AR	FOUKE	SMACKOVER
AR	GRAGG	ATOKA
AR	LAKE ERLING	SMACKOVER
AR	MASSARD	HALE
AR	MASSARD	HUNTON
AR	MASSARD	PENTERS
AR	MASSARD	SPIRO

AR	SPRINGHILL	HAYNESVILLE
AR	VILLAGE	SMACKOVER
LA	BATEMAN LAKE	10400 NG
LA	BATEMAN LAKE	10500 NE
LA	BATEMAN LAKE	10500 NE 2
LA	BATEMAN LAKE	10600 NW 1
LA	BATEMAN LAKE	10700
LA	BATEMAN LAKE	10700 NE
LA	BATEMAN LAKE	10700 SE-1
LA	BATEMAN LAKE	10700 SEG NW3
LA	BATEMAN LAKE	9600 NG
LA	BATEMAN LAKE	9600 NG-2
LA	BATEMAN LAKE	9600 NW
LA	BATEMAN LAKE	9700
LA	BATEMAN LAKE	9700 SW
LA	BATEMAN LAKE	9700 SW-1A
LA	BATEMAN LAKE	9900
LA	BATEMAN LAKE	9900 NG
LA	BATEMAN LAKE	9900 SW-2A
LA	CALHOUN	CADEVILLE
LA	CALHOUN	COTTON VALLEY
LA	CALHOUN	COTTON VALLEY D
LA	CALHOUN	HOSSTON 8800
LA	CALHOUN	HOSSTON A
LA	COTTON VALLEY	COTTON VALLEY
LA	COTTON VALLEY	COTTON VALLEY D
LA	CROWLEY	CAMERINA
LA	CROWLEY	HAYES
LA	CROWLEY	HAYES RES. D
LA	ELM GROVE	COTTON VALLEY
LA	ELM GROVE	HOSSTON
LA	KROTZ SPRINGS	6600
LA	KROTZ SPRINGS	8200
LA	KROTZ SPRINGS	8400
LA	KROTZ SPRINGS	8750
LA	KROTZ SPRINGS	9100
LA	KROTZ SPRINGS	9300
LA	KROTZ SPRINGS	COCKFIELD
LA	KROTZ SPRINGS	FRIO
LA	LAKE ARTHUR	BERTRAND
LA	LAKE ARTHUR	CAMERINA
LA	LAKE PAGIE	7200
LA	LAKE PAGIE	CIB CARST 2 SD
LA	LIRETTE	10250
LA	LIRETTE	10400
LA	LIRETTE	10500
LA	LIRETTE	10600
LA	LIRETTE	6100
LA	LIRETTE	8100
LA	LIRETTE	8200
LA	LIRETTE	8200RA
LA	LIRETTE	9400
LA	LIRETTE	9500

LA	LIRETTE	9700
LA	LOGANSPORT	GLEN ROSE
LA	LOGANSPORT	HOSSTON
LA	LOGANSPORT	JETER
LA	MIDLAND	CAMERINA
LA	MIDLAND	DISCORBIS A
LA	MIDLAND	HAYES SD.
LA	MONROE	ARKADELPHIA
LA	MONROE	GAS ROCK
LA	MONROE	HARRELL
LA	PARADIS	10000
LA	PARADIS	10400
LA	RAYNE	HMSK D-4
LA	RAYNE	HMSK E
LA	RAYNE	KLUMP D
LA	ROMERE PASS	7700
LA	ROMERE PASS	9000
LA	RUSTON	BODCAW
LA	RUSTON	COTTON VALLEY C
LA	RUSTON	COTTON VALLEY D
LA	SLIGO	COTTON VALLEY
LA	SLIGO	D
LA	SLIGO	GLEN ROSE
LA	SLIGO	HOSSTON (TRAVIS PEAK)
LA	SLIGO	JETER
LA	VALENTINE	ACOSTA RB
LA	VALENTINE	KRUMBHAAR
LA	VERNON	COTTON VALLEY
MS	BASSFIELD	HOSSTON
MS	BAXTERVILLE	EUTAW UPPER - TUSCALOOSA
MS	BAXTERVILLE	WILCOX
MS	BOVINA	COTTON VALLEY
MS	BUTTAHATCHIE RIVER	MISSISSIPPIAN CARTER
MS	CRANFIELD	PALUXY
MS	DARBUN NORTH	MOORINGSPORT
MS	FAYETTE	WILCOX
MS	GOSHEN SPRINGS	NORPHLET
MS	GRANGE	HOSSTON
MS	GREENS CREEK	HOSSTON FIRST
MS	GREENS CREEK	HOSSTON HARPER
MS	GWINVILLE	EUTAW A
MS	GWINVILLE	EUTAW B
MS	GWINVILLE	EUTAW UPPER - TUSCALOOSA
MS	GWINVILLE	GHOLAR
MS	GWINVILLE	PALUXY
MS	GWINVILLE	RODESSA
MS	GWINVILLE	SLIGO
MS	GWINVILLE	WASHITA FREDERICKSBURG
MS	HARRISVILLE	SMACKOVER
MS	HOLIDAY CREEK	HOSSTON HARPER
MS	HUB	DANTZLER 8
MS	HUB	PALUXY 11700
MS	HUB	PALUXY 11850

MS	HUB	WASHITA-FREDERICKSBURG 11200
MS	JAYNESVILLE	RODESSA
MS	JOHNS	SMACKOVER
MS	KNOXO	HOSSTON
MS	KNOXO	PALUXY UPPER
MS	KNOXO	WASHITA FREDERICKSBURG
MS	KOKOMO	PALUXY
MS	LAKE COMO	SMACKOVER
MS	MAXIE	EUTAW
MS	MAXIE	WILCOX 4400
MS	MAXIE	WILCOX 4700
MS	MERIT	RODESSA
MS	MERIT	RODESSA NORTH
MS	MONTICELLO	HOSSTON
MS	MORGANTOWN EAST	HOSSTON HARPER
MS	MULDON	MISSISSIPPIAN
MS	NEWMAN	COTTON VALLEY
MS	OAK GROVE	RODESSA A
MS	OAK GROVE	RODESSA B
MS	OAK GROVE	RODESSA WALKER
MS	OAK GROVE	RODESSA WARE
MS	OAK RIDGE	RODESSA
MS	OAKVALE	HOSSTON HARPER GAS POOL
MS	PINEY WOODS	SMACKOVER
MS	PINEY WOODS SW	SMACKOVER
MS	PISGAH SOUTH	NORPHLET
MS	PISTOL RIDGE	EUTAW - TUSCALOOSA UPPER
MS	PISTOL RIDGE	STEVENS
MS	PISTOL RIDGE	WASHITA-FREDERICKSBURG 10900
MS	PISTOL RIDGE	WASHITA-FREDERICKSBURG A
MS	PISTOL RIDGE	WILCOX 4800
MS	POPLARVILLE	HOSSTON
MS	POPLARVILLE	HOSSTON BOOTH
MS	POPLARVILLE	HOSSTON FIFTH
MS	POPLARVILLE	HOSSTON HARPER
MS	POPLARVILLE	HOSSTON LOWER
MS	POPLARVILLE	HOSSTON LOWER - HOSSTON UPPER
MS	POPLARVILLE	HOSSTON UPPER
MS	SANDY HOOK	PALUXY
MS	SANDY HOOK	WASHITA FREDERICKSBURG
MS	SHARON	EUTAW
MS	SILOAM	MISSISSIPPIAN CARTER
MS	SOSO	CHRISTMAS
MS	SOSO	RODESSA 11180
MS	SOSO	STANLEY
MS	STATE LINE SOUTH	SMACKOVER
MS	TALLAHALA CREEK	COTTON VALLEY
MS	TALLAHALA CREEK	SMACKOVER
MS	TATUMS CAMP	HOSSTON FIFTH
MS	THOMASVILLE	SMACKOVER
MS	TOPEKA	PALUXY
MS	TRIMBLE	STANLEY
MS	WAVELAND	MOORINGSPORT

MS	WHITESAND	HOSSTON
MS	WHITESAND	SLIGO

4) CO_2 Storage in Saline Reservoirs. 11 saline reservoirs are included in the screening tool. At this point, only a limited amount of data is available for saline reservoirs. Saline reservoirs that occur within established oil and gas fields (and are located below the oil/gas caprock) are considered the safest options for the initial deployment of saline reservoir CO_2 sequestration. A sample dataset of those reservoirs from Alabama and Mississippi are included in the screening tool. A listing of the reservoirs is provided below.

State	Field	Reservoir
AL	POLLARD	LOWER TUSCALOOSA MASSIVE SAND UNIT
AL	SOUTH CARLTON	LOWER TUSCALOOSA MASSIVE SAND UNIT
AL	STAUFFER	LOWER TUSCALOOSA
MS	BAXTERVILLE	LOWER TUSCALOOSA MASSIVE SAND UNIT
MS	CARTHAGE POINT, CRANFIELD	LOWER TUSCALOOSA
MS	CHATAWA, MCCOMB	LOWER TUSCALOOSA MASSIVE SAND UNIT
MS	DEXTER	LOWER TUSCALOOSA
MS	HUB, SANDY HOOK	LOWER TUSCALOOSA
MS	LITTLE CREEK, MALLALIEU, BROOKHAVEN	LOWER TUSCALOOSA
MS	MAXIE	LOWER TUSCALOOSA
MS	PISTOL RIDGE, STEWARD	LOWER TUSCALOOSA MASSIVE SAND UNIT

ATTACHMENT B:
CO2-EOR, ECBM, DEPLETED OIL AND GAS, AND SALINE FORMATION ECONOMIC MODEL DESCRIPTIONS

The cost and economic models for storing CO_2 with CO_2-EOR or ECBM and storing CO_2 in depleted oil and gas reservoirs as well as in saline formation are provided below.

These models provide a useful “first order” estimate for costs. Modified versions of these costs and economic models, that would incorporate regional cost differences and other features, would be developed as part of a Phase III SBIR application.

A. Cost Model for CO_2-Based Enhanced Oil Recovery (CO_2-EOR) (Mississippi Example)

This appendix provides documentation for the cost module developed by Advanced Resources. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO_2-EOR, CO_2 sequestration, or ECBM project:

1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on industry drilling cost data.

The well D&C cost equation was derived from fitting a line through a graph of drilling costs versus depth. The total equation is:

Well D&C Costs = $a_0 D^{a1}$
Where: a_0 is 1.4×10^{-4}
a_1 is 2.1
D is well depth

For example, the cost of drilling and completing a well to 10,000 ft is \$3.6 MM.

2. Lease Equipment Costs for New Producing Wells. The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1 D$
Where: c_o = \$70,000 (fixed)
c_1 = \$31.00 per foot
D is well depth

3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new CO_2-EOR well includes gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from industry data and the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation is:

Injection Well Equipping Costs = $c_0 + c_1 D$

Where: c_o = \$27,000 (fixed)
c_1 = \$5.60 per foot
D is well depth

4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation is:

Well Conversion Costs = $c_0 + c_1 D$
Where: c_o = \$70,000 (fixed)
c_1 = \$10.00 per foot
D is well depth

5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing production injection well requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for is:

Well Conversion Costs = $c_0 + c_1 D$
Where: c_o = \$50,000 (fixed)
c_1 = \$10.00 per foot
D is well depth

6. Annual Production Well O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs for West Texas and are used as a guide for Mississippi. To account for the O&M cost differences between waterflooding and CO_2-EOR/sequestration/ECBM, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR/sequestration/ECBM projects. Liquid lifting are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs. (Liquid lifting costs for CO_2-EOR are discussed in a later section of this appendix.)

The equation is:

Well O&M Costs = $b_0 + b_1 D$
Where: b_0 = \$34,000 (fixed)
b_1 = \$4.00 per foot
D is well depth

7. CO_2 Recycle Plant Investment Cost. Operation of CO_2-EOR or ECBM projects requires a recycling plant to capture and reinject the produced CO_2. The size of the recycle plant is based on peak CO_2 production and recycle requirements.

The cost of the recycling plant is set at \$300,000 per MMcfd of maximum CO_2 recycle for projects with a maximum recycle rate of 30 MMcfd or greater and are scaled down from there.

For example, project in the Lower Tuscaloosa reservoir of the Cranfield oil field, with 112 MMcfd of maximum CO_2 reinjection and 51 injectors, requires a recycling plant costing $34 million.

The model has three options for installing a CO_2 recycling plant. The default setting costs the entire plant one year prior to CO_2 breakthrough. The second option places the full CO_2 recycle plant cost at the beginning of the project (Year 0). The third option installs the CO_2 recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO_2 breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached. In this study, we have applied the default option

8. Other Model Costs.

a. CO_2 Recycle O&M Costs. The O&M costs of CO_2 recycling are adjustable by the user and are by default set at $1.00 per mcf.

b. Lifting Costs. Liquid (oil and water) lifting costs are calculated on total liquid production and cost at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

c. CO_2 Distribution Costs. The CO_2 distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased CO_2 to the project site.

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $120,000 per mile for 4" pipe (CO_2 rate less than 15MMcfd), $180,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcfd), $240,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcfd), and $300,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcfd). Aside from the injection volume, costs also depend on the distance from the CO_2 "hub" (transfer point) to the oil field. Currently, the default distance is set at 10 miles.

The CO_2 distribution cost equation is:

Pipeline Construction Costs = $150,000 + C_D*Distance

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO_2 injection rate)
Default distance = 10.0 miles

d. G&A Costs. General and administrative (G&A) costs of 20% are added to OPEX and CAPEX costs.

e. Royalties. Royalty payments are assumed to be 12.5%.

f. Production Taxes. Severance and ad valorum taxes in the cashflow model are set at the corresponding state's rates on the oil production. The state of Mississippi currently has a severance tax rate of 6.0% on oil and gas production and no ad valorum rate. Tax data were gathered from the 2005 IOGCC Summary of State Statutes and Regulations.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis differential for Mississippi (-

\$0.60 per barrel) and the current gravity differential (-\$0.25 per ^oAPI, from a basis of 40 ^oAPI) into the average wellhead oil price realized by each oil reservoir. The equation for is:

Wellhead Oil Price = Oil Price + (-\$0.60) – [\$0.25*(40 - ^oAPI)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^oAPI is oil gravity

If the oil gravity is less than 40 ^oAPI, the wellhead oil price is reduced; if the oil gravity is greater than 40 ^oAPI, the wellhead oil price is increased.

No basis is applied to the natural gas price in Mississippi.

B. Cost Model for CO_2-ECBM (CO_2-ECBM) (Alabama Example)

This appendix provides documentation for the cost module developed by Advanced Resources. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO_2-EOR, CO_2 sequestration, or ECBM project:

1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on industry drilling cost data.

The well D&C cost equation was derived from fitting a line through a graph of drilling costs versus depth. The total equation is:

Well D&C Costs = a_0D^{a1}
Where: a_0 is 1.4×10^{-4}
a_1 is 2.1
D is well depth

For example, the cost of drilling and completing a well to 5,000 ft is \$0.85 MM.

2. Lease Equipment Costs for New Producing Wells. The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$70,000 (fixed)
c_1 = \$31.00 per foot
D is well depth

3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new ECBM well includes gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from industry data and the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation is:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$27,000 (fixed)

c_1 = \$5.60 per foot
D is well depth

4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$70,000 (fixed)
c_1 = \$10.00 per foot
D is well depth

5. Costs of Reworking an Existing Production or Injection Well for CO_2-ECBM (First Rework). The reworking of existing production injection well requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$50,000 (fixed)
c_1 = \$10.00 per foot
D is well depth

6. Annual Production Well O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs for West Texas and are used as a guide for Alabama. To account for the O&M cost differences between waterflooding and CO_2-EOR/sequestration/ECBM, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR/sequestration/ECBM projects. Liquid lifting are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs. (Liquid lifting costs for CO_2-EOR are discussed in a later section of this appendix.)

The equation is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$34,000 (fixed)
b_1 = \$4.00 per foot
D is well depth

7. CO_2 Recycle Plant Investment Cost. Operation of ECBM projects requires a recycling plant to capture and reinject the produced CO_2. The size of the recycle plant is based on peak CO_2 production and recycle requirements.

The cost of the recycling plant is set at $300,000 per MMcfd of maximum CO_2 recycle for projects with a maximum recycle rate of 30 MMcfd or greater and is scaled down from there. For example, an ECBM project in the Big Sandy Creek field in the Black Warrior Basin, with 331 MMcfd of maximum CO_2 reinjection and 416 injectors, requires a recycling plant costing $99 million.

The model has three options for installing a CO_2 recycling plant. The default setting costs the entire plant one year prior to CO_2 breakthrough. The second option places the full CO_2 recycle plant cost at the beginning of the project (Year 0). The third option installs the CO_2 recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO_2 breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached. In this study, we have applied the default option

8. <u>Other Model Costs.</u>

a. <u>CO_2 Recycle O&M Costs.</u> The O&M costs of CO_2 recycling are adjustable by the user and are by default set at $1.00 per mcf.

b. <u>Lifting Costs.</u> Liquid (water) lifting costs are calculated on total liquid production and cost at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

c. <u>CO_2 Distribution Costs.</u> The CO_2 distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased CO_2 to the project site.

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $120,000 per mile for 4" pipe (CO_2 rate less than 15MMcfd), $180,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcfd), $240,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcfd), and $300,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcfd). Aside from the injection volume, costs also depend on the distance from the CO_2 "hub" (transfer point) to the oil field. Currently, the default distance is set at 10 miles.

The CO_2 distribution cost equation is:

Pipeline Construction Costs = $150,000 + C_D*Distance

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO_2 injection rate)
Default distance = 10.0 miles

d. <u>G&A Costs.</u> General and administrative (G&A) costs of 20% are added to OPEX and CAPEX costs.

e. <u>Royalties.</u> Royalty payments are assumed to be 12.5%.

g. <u>Production Taxes.</u> Severance and ad valorum taxes in the cashflow model are set at the corresponding state's rates on the oil production. The state of Alabama currently has a severance tax rate of 10.0% on gas production and no ad valorum rate. Tax data were gathered from the 2005 IOGCC Summary of State Statutes and Regulations.

C. Cost Model for Depleted Oil and Gas Fields (Mississippi Example)

This appendix provides documentation for the cost module developed by Advanced Resources. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO_2-EOR, CO_2 sequestration, or ECBM project:

1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on industry drilling cost data.

The well D&C cost equation was derived from fitting a line through a graph of drilling costs versus depth. The total equation is:

Well D&C Costs = $a_0 D^{a1}$
Where: a_0 is 1.4×10^{-4}
a_1 is 2.1
D is well depth

For example, the cost of drilling and completing a well to 10,000 ft is $3.6 MM.

2. Lease Equipment Costs for New Injection Wells. The costs for equipping a new CO_2-EOR well includes gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from industry data and the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation is:

Injection Well Equipping Costs = $c_0 + c_1 D$
Where: c_o = $27,000 (fixed)
c_1 = $5.60 per foot
D is well depth

3. Converting Existing Production Wells into Injection Wells. The conversion of existing oil or gas production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation is:

Well Conversion Costs = $c_0 + c_1 D$
Where: c_o = $70,000 (fixed)
c_1 = $10.00 per foot
D is well depth

5. Costs of Reworking an Existing Production or Injection Well for CO_2 Injection (First Rework). The reworking of existing production injection well requires pulling and replacing

the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = $50,000 (fixed)
c_1 = $10.00 per foot
D is well depth

5. Other Model Costs.

a. G&A Costs. General and administrative (G&A) costs of 20% are added to OPEX and CAPEX costs.

D. Cost Model for Saline Formations (Mississippi Example)

This appendix provides documentation for the cost module developed by Advanced Resources. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO_2-EOR, CO_2 sequestration, or ECBM project:

1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on industry drilling cost data.

The well D&C cost equation was derived from fitting a line through a graph of drilling costs versus depth. The total equation is:

Well D&C Costs = a_0D^{a1}
Where: a_0 is 1.4×10^{-4}
a_1 is 2.1
D is well depth

For example, the cost of drilling and completing a well to 10,000 ft is $3.6 MM.

2. Lease Equipment Costs for New Injection Wells. We assume all new injection wells for saline aquifer projects. The costs for equipping a new CO_2-EOR well includes gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from industry data and the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation is:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$27,000 (fixed)
c_1 = \$5.60 per foot
D is well depth

3. <u>Other Model Costs.</u>

a. G&A Costs. General and administrative (G&A) costs of 20% are added to OPEX and CAPEX costs.

ATTACHMENT C:
SUPPORTING DETAIL FOR CO2 PIPELINE DESIGN AND COST MODEL

CO_2 Pipeline Design and Cost Model.

Establishing Pipeline Specifications.

The first step is calculating the internal pipeline diameter, which itself requires calculating CO_2 density and viscosity at expected operating temperature and pressures.

The model uses ambient temperature and pipeline operating pressure (calculated as the average of pressure into and out of pipeline) to calculate density and viscosity, both of which are calculated using regression analysis[1]. A set of lookup tables have been integrated into the model that display a series of coefficients that can be applied to a 6th order polynomial equation to estimate CO_2 density or viscosity at given temperatures and pressures.

After determining the physical characteristics of the CO_2, the model uses a system of equations to calculate optimal pipeline diameter. This is an iterative process, because pipeline diameter must be known to calculate the fanning friction factor, which is itself a determinant of pipeline diameter. The model begins with an assumed diameter of 10 inches and iterates this system of equations 16 times.

Equation 1: Pipeline Diameter

$$D = 39370 * [(32* F_f * m^2) *1.33E^4 / (\pi^2*\rho*(\Delta P/L)*1000]^{(1/5)}$$

Where:
D equals pipeline diameter, in inches,
ρ denotes CO_2 density
L is pipeline length measured in kilometers
m = is CO_2 mass flowrate, in tons per day
ΔP is the differential between pipeline inlet and outlet pressure in MPa
F_f is the fanning friction factor, the equation for which is given below:

Equation 2: Fanning Friction Factor

$$F_f = \frac{1}{4\left[-1.8\log_{10}\left\{\frac{6.91}{\mathrm{Re}} + \left(\frac{12(\varepsilon/D)}{3.7}\right)^{1.11}\right\}\right]^2}$$

Where:
ε is pipeline roughness, an assumed model constant of .00015 ft
D is either the initial pipeline diameter or the diameter from the previous iteration and
Re is the Reynolds number, the equation for which is listed below:

Equation 3: Reynolds Number

$$Re = 1.8226 * m / (\pi*\mu*D)$$

[1] McCollum, D. L., Ogden, J.M. *Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage and Correlations for Estimating Carbon Dioxide Density and Viscosity.* Institute of Transportation Studies, University of California, Davis. 2006.

Where:
μ is CO_2 viscosity
m = is CO_2 mass flowrate, in tons per day
D is either the initial pipeline diameter or the diameter from the previous iteration

The final internal pipeline diameter as calculated from the above equations queried against a lookup table of IPSCO pipe diameters. The closest value of internal diameter to the result is assumed to be the diameter design specification for the pipeline being evaluated.

Establishing Overall Pipeline Capital Costs

The capital costs for materials, labor, right of way and miscellaneous items are estimated through regression analysis[2]. Each cost item is governed by the following cost equation, displayed in 2009 dollars.

Equation 4: CO_2 Transportation Capital Costs

$$\text{Materials Cost (\$)} = (388 * D^2 + 806 * D + 31{,}650) * L + 41{,}090$$

$$\text{Labor Cost (\$)} = (381 * D^2 + 2{,}302 * D + 188{,}714) * L + 205{,}350$$

$$\text{Miscellaneous Cost (\$)} = (8{,}284 * D + 7{,}412) * L + 92{,}650$$

$$\text{Right of Way Cost (\$)} = (629 * D + 65{,}400) * L + 43600$$

Where:
D = Pipeline Diameter, in inches (from Table of IPSCO pipeline diameters)
L = Pipeline Length, in miles

The model allow for the user to select a "Terrain Factor" to account for increased costs inherent in building pipelines in difficult environs. If the user selects such an option, total pipeline capital costs are multiplied by a factor ranging from 1-1.5, depending on the type of terrain. Based on user-entered discount rate, project length, and CO_2 flow rate, these costs are then levelized and annualized.

Establishing Booster Station Specifications and Capital Costs.

Depending on the distance the CO_2 will be transported and the desired outlet CO_2 pressure, booster stations may be required along the length of the pipeline for pressure maintenance.

Booster station capital costs are calculated assuming $2,000 per installed horsepower. The equation for calculating the horsepower requirement of booster stations is given below[3].

Equation 5: Booster Station Horsepower

$$HP = (Q * \Delta P) / (26.865 * \acute{\eta}_p)$$

---

[2] Parker, N. *Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs"* Institute of Transportation Studies, University of California, Davis. 2004.

[3] International Energy Agency, Greenhouse Gas Initiative. *Transmission of CO_2 and Energy*. Report Number PH4/6. March 2002

Where:

HP is booster station horsepower
Q is CO_2 flow rate (m^3/hour)
ΔP is pressure increase through booster (bar), which is assumed to be 40 bar
$\acute{\eta}_p$ is the booster station pump efficiency, assumed to be 70%

Booster station capital costs are annualized and levelized based upon method listed above.

Currently, the model does not independently determine whether booster stations will be needed. Instead, it relies on the user-entered average distance between required booster stations along the pipeline. If the average distance between booster stations is less than the total pipeline length, the model calculates the number of booster stations required and includes booster station costs in its capital cost calculations.

As a first step, the model calculates a pipeline diameter to allow for the user set outlet pressure to be maintained. Pressure can also be maintained by using smaller pipeline diameters and adding booster stations along the length of the pipeline. In some instances, this option will be less expensive, because less steel will be needed for long pipelines.

In this instance, the user can set their desired pipeline outlet pressure and vary the length of the pipeline until the desired pipeline diameter is reached. This length value represents the correct spacing between booster stations to maintain pipeline pressure over longer distances.

Operating and Maintenance Costs

The costs for operating and maintaining (O&M) the pipeline and the booster stations are set forth below:

Pipeline. Annual Pipeline O&M costs are calculated as 5% of total operating costs.

Booster Station. Booster station annual O&M costs are calculated as a user-defined percentage, typically 5%, of total booster capital costs.

Booster electricity usage is determined using the following equation:

$$P_P = HP * .7456 * CF * 8760$$

Where:

P_p is pump power use (kWh/year)
HP is installed booster station horsepower
CF is the project capacity factor

ATTACHMMENT D:
SCREENING TOOL USERS MANUAL

Screening Tool Users Manual

Opening the Screening Tool

1. Navigate to the icon placed on the desktop during installation and double click.

OR

1. Navigate to Start → All programs → SBIR → ***Program Name*** and click.

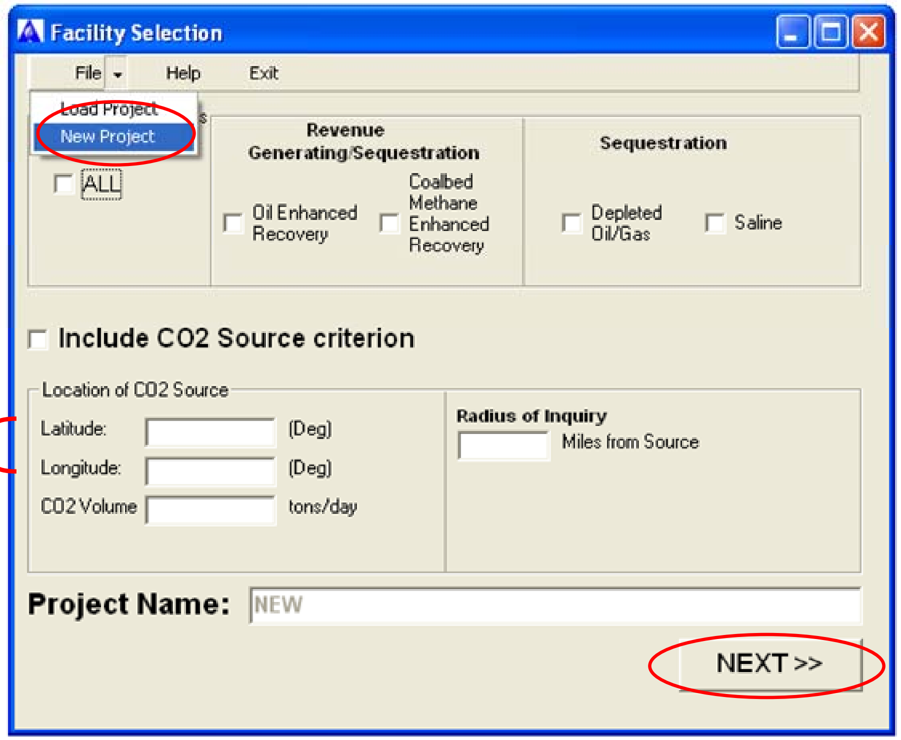
2. After the program opens, this screen should appear.

3. Click Next

The Screening Tool allows reservoir simulation and economic assessment of four different kinds of CO2 storage reservoirs within one program.

Creating a New Project

1. Under the ***File*** dropdown menu, select ***New Project***



2. Select the type of reservoir by checking one or multiple ***Reservoir Type*** boxes

3. Click the ***Include CO2 Source criterion*** box and enter the Latitude and Longitude values for the selected source

4. Enter a distance in the ***Radius of Inquiry*** box to use in the search for available reservoirs

5. Click ***Next***

- Users can individually select each type of reservoir, or any combination of reservoir types for assessment
- If the user is assessing CO2 storage options within the vicinity of a stationary CO2 source, the model can assist the user in identifying local options.
- To do that, the user enters data on the CO2 source including its location (lat and lon, in degrees), average CO2 volume (in tons per day) and a radius of inquiry (in miles)
- If the source criteria are not entered, all reservoir options of the type(s) selected will be candidates for assessment

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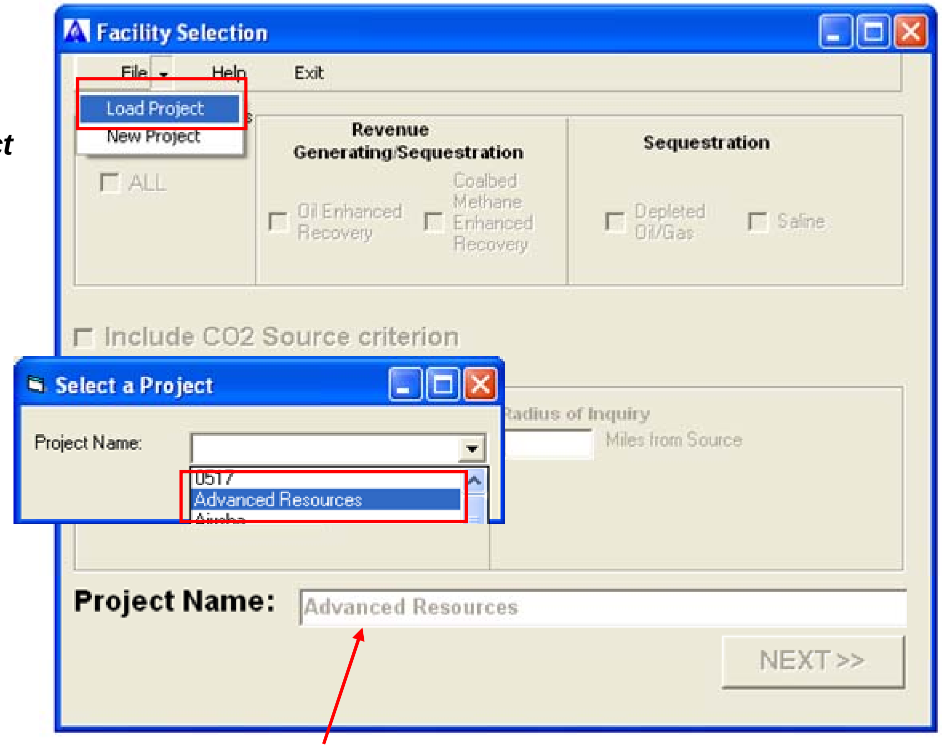
Loading a Project

1.From the ***File*** dropdown menu, select ***Load Project***

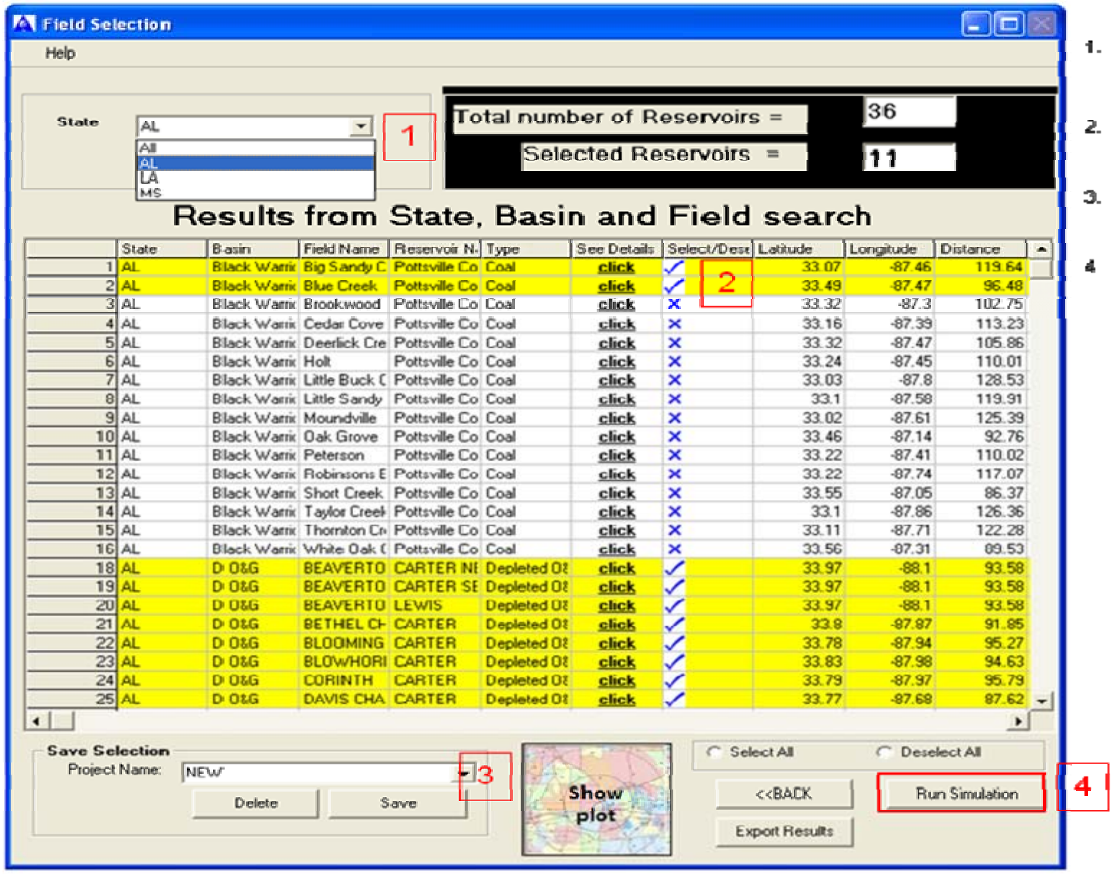


2. The ***Select a Project*** dialogue box will appear. Use the ***Project Name*** dropdown menu to select the name of the saved project

3.Once the correct project is selected, click ***Next*** to run the simulation (this will bring window on pg 5. Follow instructions on pg 5 to continue further)

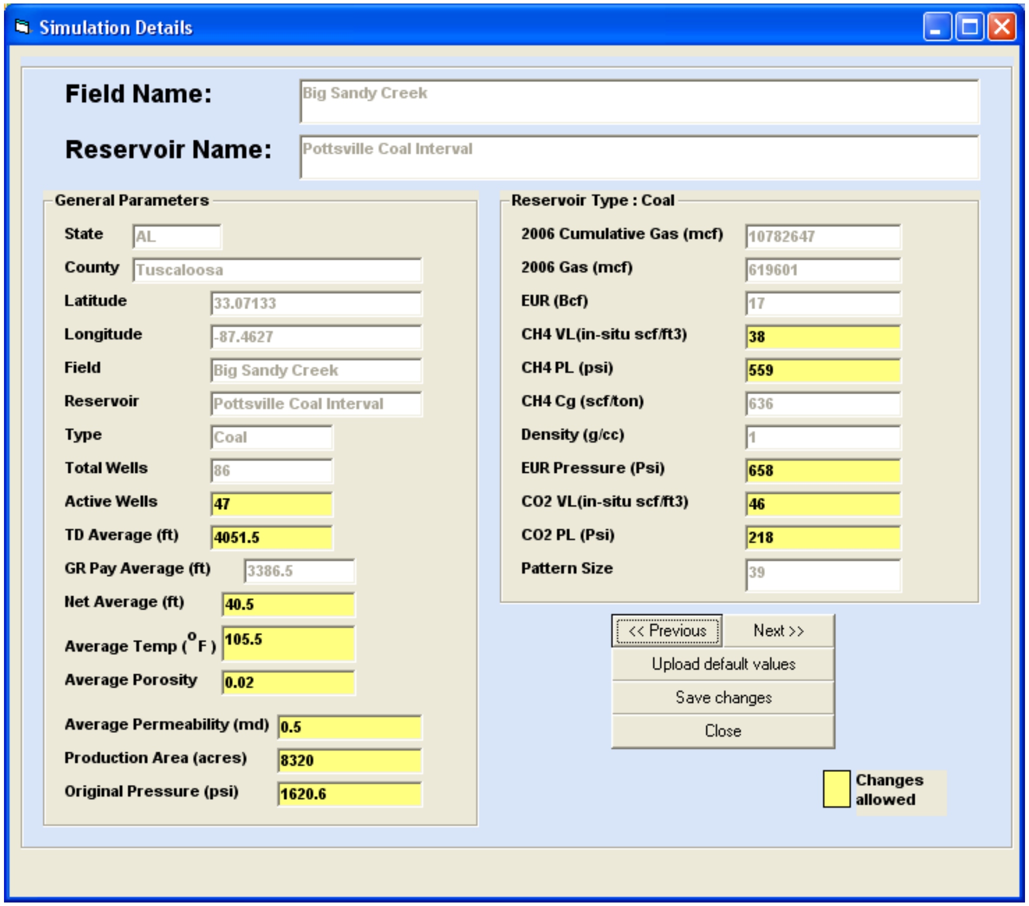
After a project is selected, its name will appear in the ***Project Name*** field.

- If the user is loading an existing project, the "Facility Selection" window get populated automatically with all the options that were initially used to create the project
- Select the correct project from the small pop up window and verify the name before proceeding to the next step



1. Select the state of interest in the *State* drop-down box
2. Click on the icon in the *Select Deselect* column to highlight the correct fields
3. Type the name of the project into the Project Name, then click Save
4. Once the appropriate fields are selected, click Run Simulation

- The user may select or deselect an individual row (i.e. a reservoir) or by toggling between the “Select All” and “Deselect All” options
- By clicking on the “see details” button, the user may see an individual reservoir’s data and may modify some of those values
- By clicking on the “Show plot” button, the user may see the location of all selected reservoirs in relation to the source location (if entered in the prior screen)
- The entire table can be exported to an Excel spreadsheet for any further analysis by the user
- After the user has refined the reservoir selection, clicking “run simulation” button will proceed to the simulation module



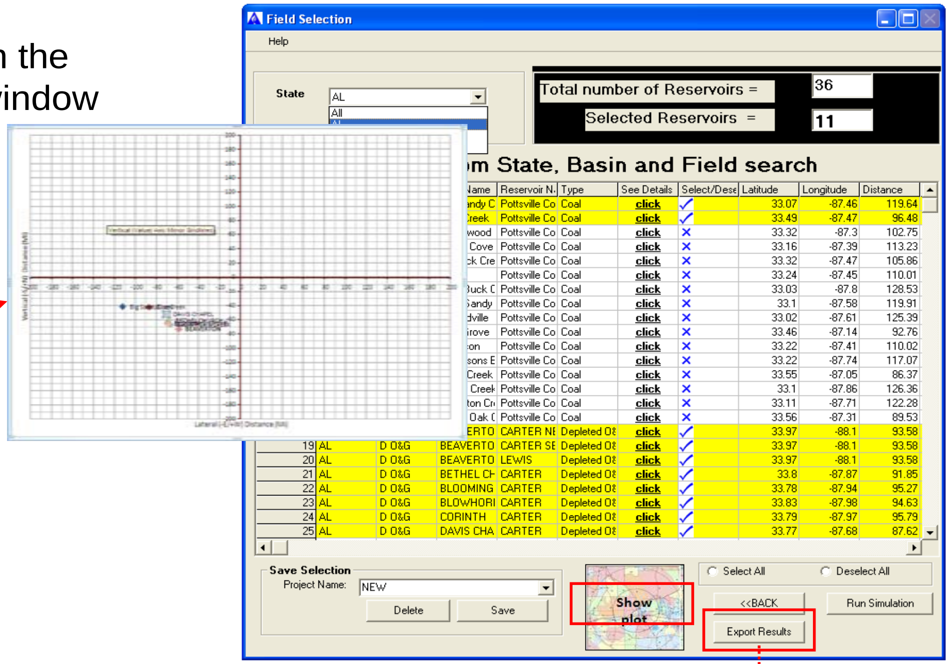
- By clicking on the "see details" button in the "Field Selection" window, the user may see an individual reservoir's data and may modify some of those values
- Users may alter and save data for each reservoir individually. Cells in the tan color may be modified by the user and injection simulation will be conducted based on the updated values
- Clicking the "upload default values" button will allow the user the re-set the data to those in the original dataset

Creating a New Project (cont.)

<u>Note</u> other options on the ***Field Selection*** window

1. To view the location and name of the selected Reservoirs click on ***Show Plot*** located in the lower middle portion of the window. An *excel document* will open showing the location of the reservoirs.

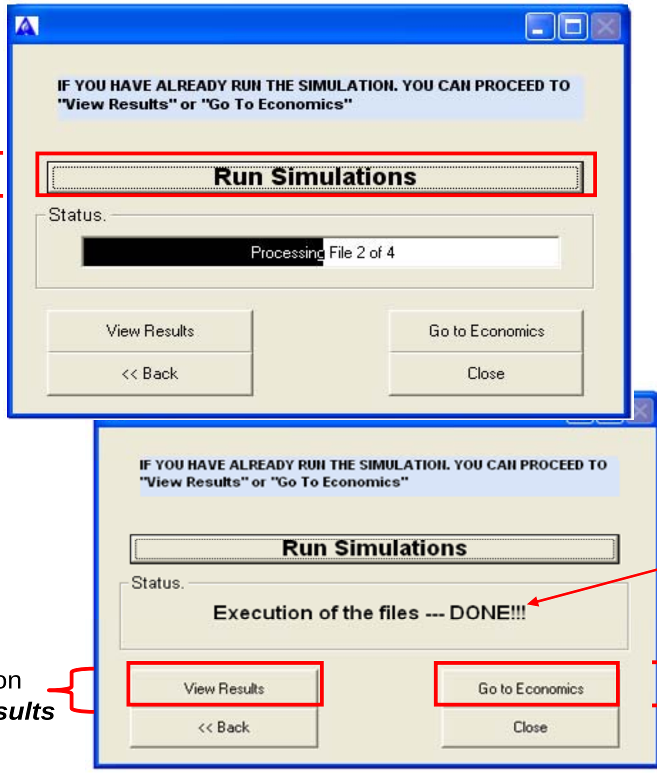
2. By selecting ***Export Results*** on the lower right section of the ***Field Selection*** page an excel spreadsheet will open with summary information on each selected reservoir.

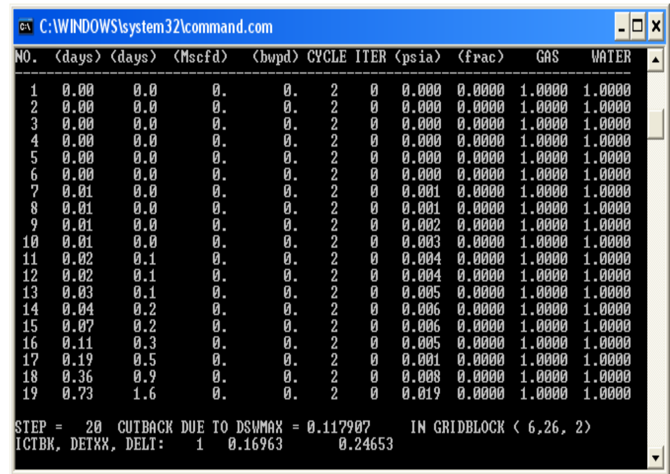


- By clicking the "Show plot" button in the "Field Selection" window an Excel plot with reservoir locations within the radius of investigation is shown.
- Using this tool, the user can refine the reservoir selection to limit their assessment of reservoirs within a "fairway" or cluster and eliminate outliers
- The distances between the source and storage reservoir are used in the transportation cost model

Running the Simulations

1. Click on ***Run Simulations***





After the simulation is complete this message should appear

2. Click on ***View Results***

3. To view cash flow analysis, click ***Go to Economics***

- The MS DOS window on the above right side shows the simulation run of Saline Reservoir in Comet3 simulator. The user will notice such windows pop up when simulation starts and automatically close once the simulation ends
- Once the simulations are completed, the user can either view the simulation results of all the runs or go directly to economics.

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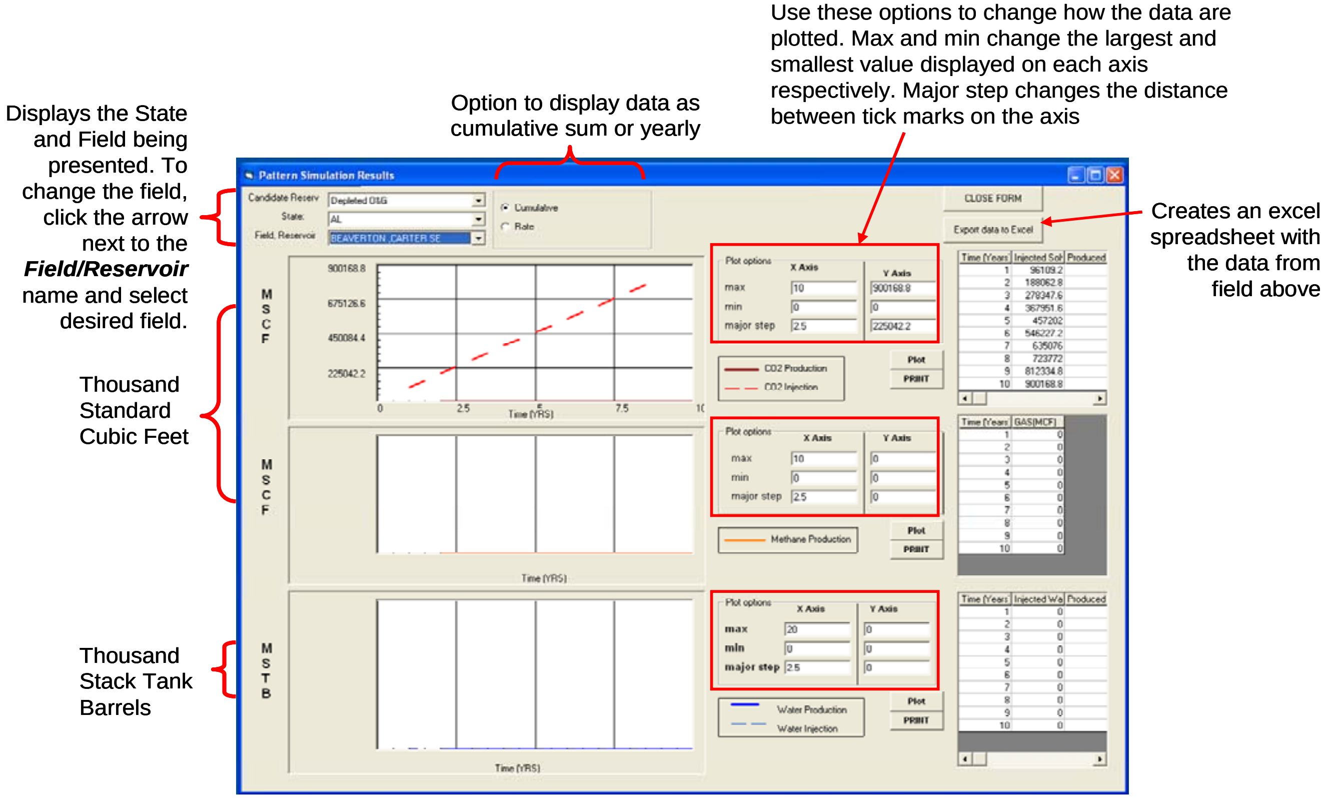
Interpreting Production Results



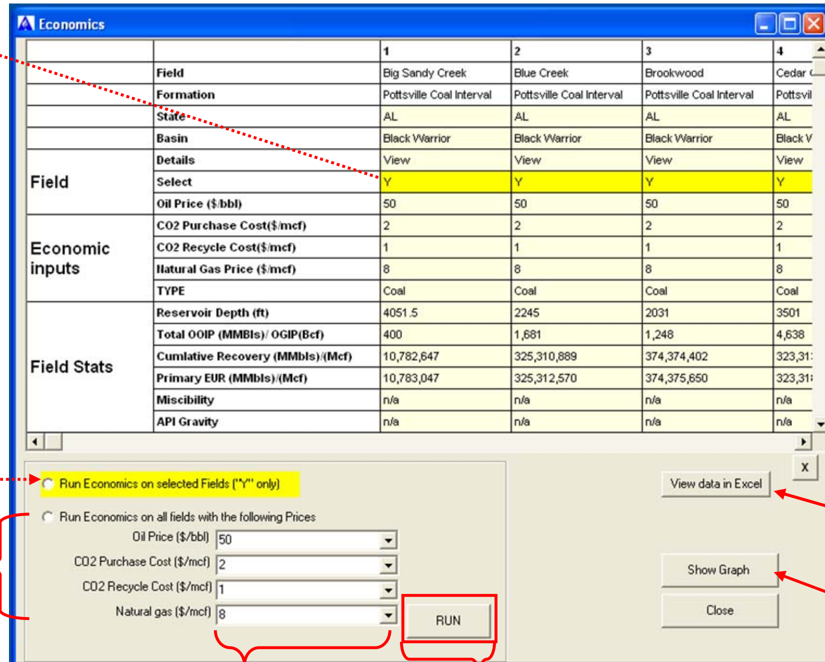
- Clicking the "View Results" button in the "Run Simulations" window will take the user to a screen where the simulation data can be observed
- Plots in this window show production/injection data vs. time for each individual reservoir pattern simulation. Plots can be recreated by changing scale on the axis and selecting the desired set of data (i.e. cumulative or rate data)
- Results can be exported to an Excel spreadsheet for any further analysis

Interpreting Economic Results

In this row, fields can be deselected and excluded from the Economic output file

If necessary, deselect unwanted fields here, and check ***Run Economics on Selected Fields*** to exclude the deselected fields from the Economic output file

This box allows you to enter different assumptions about the resource and input prices.



This field presents the results from cash flow analysis. Each column corresponds to a different field/reservoir. Use the scroll bar to view all the rows. For more information, see Explanation of Economics Results

To view the data output in an Excel spreadsheet, click ***View Data in Excel***

Clicking this button will open an advanced graphical display of results. See **Interpreting Economics Graphic Results**

1. To change these assumptions, first select the ***Run Economics on all Fields with the following Prices,*** then select desired prices from the dropdown menus.

2. After selecting the desired prices, click ***Run*** to view results

- Clicking the "Go To Economics" button in the "Run Simulations" window will take the user to a screen where the reservoir's economic performance can be observed
- Values in the "Economic Inputs" section of the table can be changed and economics can be re-assessed on one individual field or all the fields. Users have the option to select different economic input values for each field or same values for all the fields.
- The table can be exported into an Excel spreadsheet

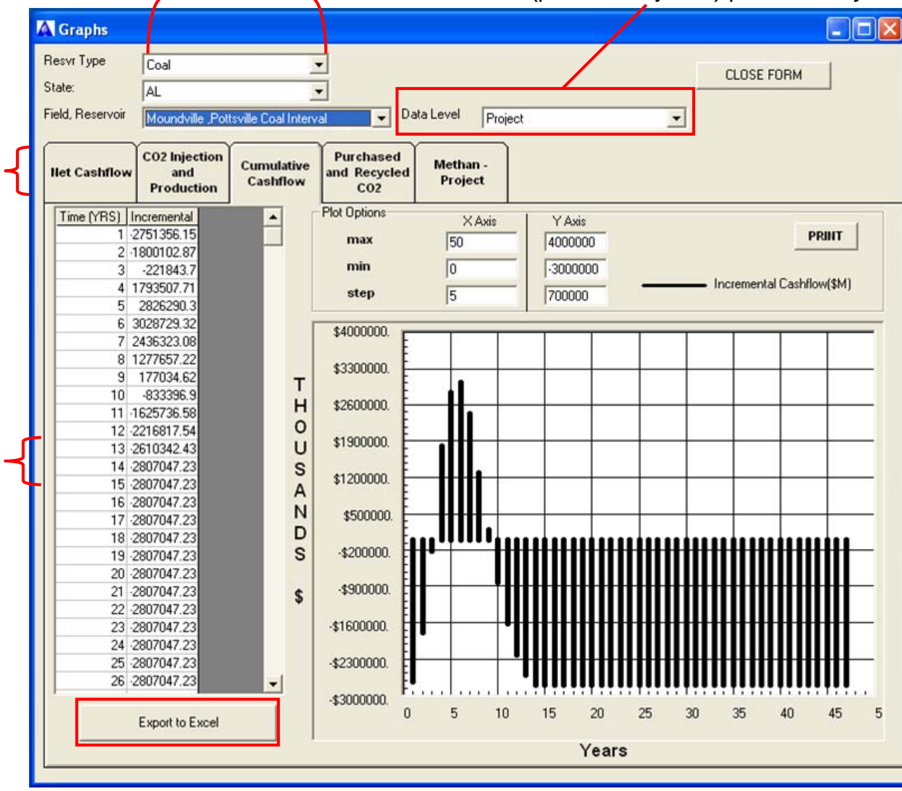
Interpreting Economic Graphic Results

These fields display the state and field/reservoir being analyzed. To change field, select the desired field from the ***Field/Reservoir*** drop down menu

The ***Data Level*** drop down menu allows user to chose to view field well analysis or individual (producer/injector) pattern analysis

Clicking on these tabs will display graphical analysis of various project metrics

This field displays the relevant data to the economic analysis being performed and is shown in graphical form in the pane to the right. Use the ***Export to Excel*** below to view this data in Excel



Use these options to change how the data are plotted. Max and min change the largest and smallest value displayed on each axis respectively. Major step changes the distance between tick marks on the axis

- By clicking the "Show Graph" button in the "Economics" window, the user is shown the economic data for individual reservoirs in graphical and table format
- Above is the graphical view of the Economics data. Data can viewed on the Pattern or Project level for each individual reservoir. Hitting the "Print" button will either print to local printer or save the plot in pdf format.
- The table can be imported into an Excel spreadsheet

Glossary

Details	Opens an advanced attribute editor for the field in question
Select	Toggles "Y" or "N" to apply user-defined changes in input pricing to given field
State	Two letter abbreviation for the Field State
Basin	Basin location of the Field
Field	Field Name
Formation	Name of geologic formation where production/injection is occurring
Oil Price ($/bbl)	Price of Oil
CO_2 Purchase Cost($/mcf)	Cost of CO_2 for purchaser (at field gate)
CO_2 Recycle Cost($/mcf)	Cost of reinjecting CO_2 produced from producer well
Depth	Depth of well in feet
Total OOIP	Total Original Oil in Place (MMbls)
Cum Recovery	Amount of Oil recovered to date (MMbls)
Primary EUR	Estimated Ultimate Recovery potential of field (MMbls)
Miscibility	Miscible or Immiscible Flood
API Gravity	American Petroleum Institute (°API) gravity; measures ratio of oil density to water
Patterns	Number of Injection/Production well patterns in Field
Existing Injectors Used	Number of preexisting wells used as injector wells
Convertible Producers Used	Number of wells converted into producers
New Injectors Drilled	Number of new injector wells drilled
Existing Producers Used	Number of existing wells used as producer wells
New Production Drilled	Number of new producer wells drilled
Pattern Cum Oil	Cumulative amount of oil produced (Mbls) in each pattern
Pattern CumH_2O	Cumulative amount of water produced (Mbls) in each pattern
Pattern Gross CO_2	Total amount of CO_2 injected (MMcf) into each pattern
Pattern Purchased CO_2	Total amount of CO_2 purchased (MMcf) per pattern for injection
Pattern Recycled CO_2	Total amount of CO_2 recycle (MMcf) per pattern
CUM H_2O ($/bbl)	Costs of produced levelized per bbl of oil produced
Gross CO_2 ($/bbl)	Total amount of CO_2 costs levelized per bbl of oil produced (includes Purchased and Recycled CO_2)
Purchased CO_2($/bbl)	Purchased CO_2 costs levelized per bbl of oil produced
Recycled CO_2($/bbl)	Recycled CO_2 costs levelized per bbl of oil produced
Field Cum Oil	Amount of Oil produced (MMbls) in entire field
Field OOIP	Amount of Original Oil in Place in entire field (MMbbls)
Field Cum H_2O	Amount of water produced in entire field (MMbbls)
Field Gross CO_2	Amount of CO_2 injected in entire field (MMcf)
Field Purchased CO_2	Amount of CO_2 purchased (MMcf) – ***this also represents the volume of CO2 sequestered***
Field RecCO_2	Amount of CO_2 recycled in entire field (MMcf)
Field PayBack	Length of time (in years) until initial capital costs are recovered
Field ProjLength	Length of time (in years) project will be operational
TotalRevenue	Total amount of revenue (in $1,000 x dollars) - by pattern
TotalCapInvst	Total price of necessary capital (in $1,000 x dollars) - by pattern
TotalCO_2 Cost	Cost of all CO_2 used in project (in $1,000 x dollars) - by pattern
TotalO_MCosts	Total operation and maintenance costs (in $1,000 x dollars) - by pattern
Total Cap Invt ($/bbl)	Capital costs levelized per bbl of oil produced
Total CO_2 Cost ($)	Total cost of CO_2 levelized per bbl of oil produced
Total O_M_Cost ($/bbl)	Total O&M costs levelized per bbl of oil produced
Pattern IRR(BTx)	Before tax internal rate of return per pattern
Project IRR(BTx)	Project-wide before tax internal rate of return