Economic Evaluation of CO₂ Sequestration Technologies

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Bert R. Bock (TVA), Richard G. Rhudy (EPRI), and David E. Nichols (TVA)

**Tennessee Valley Authority
P.O. Box 1010
Muscle Shoals, AL 35662-1010**

**Michael Klett
Parsons Infrastructure and Technology Group Inc.
1 Meridian Boulevard, Suite 2B-1
Wyomissing, PA 19610**

**Daryll Ray
University of Tennessee
Department of Agricultural Economics
and Rural Sociology
Agricultural Policy Analysis Center
310 Morgan Hall
Knoxville, TN 37996-4500**

**Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303**

**Howard Herzog
MIT Energy Laboratory, Room E40-471
Cambridge, MA 02139**

**John Davison
IEA Greenhouse Gas R&D Programme
CRE Group Ltd., Stoke Orchard
Cheltenham, Gloucestershire
GL52 4RZ, United Kingdom**

**Dale Simbeck
SFA Pacific
444 Castro Street, Suite 920
Mountain View, CA 94041**

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Abstract

In order to plan for potential CO₂ mitigation mandates, utilities need better information on CO₂ mitigation options, especially carbon sequestration options that involve non-utility operations. One of the major difficulties in evaluating CO₂ sequestration technologies and practices, both geologic storage of captured CO₂ and storage in biological sinks, is obtaining consistent, transparent, accurate, and comparable economics. This project is comparing the economics of major technologies and practices under development for CO₂ sequestration, including captured CO₂ storage options such as active oil reservoirs, depleted oil and gas reservoirs, deep aquifers, coal beds, and oceans, as well as the enhancement of biological sinks such as forests and croplands. An international group of experts has been assembled to compare on a consistent basis the economics of this diverse array of CO₂ sequestration options. Designs and data collection are nearly complete for each of the CO₂ sequestration options being compared. Initial spreadsheet development has begun on concepts involving storage of captured CO₂. No significant problems have been encountered, but some additional outside expertise will be accessed to supplement the team's expertise in the areas of life cycle analysis, oil and gas exploration and production, and comparing CO₂ sequestration options that differ in timing and permanence of CO₂ sequestration. Plans for the next reporting period are to complete data collection and a first approximation of the spreadsheet. We expect to complete this project on time and on budget.

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1.0 Introduction

An overview of this project, including concepts to be compared, objective, general project description and methodology, project schedule, and listing of team members was presented at the First National Conference on Carbon Sequestration and published in the proceedings: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/7c4.pdf. Our conference paper is inserted starting on the next page and provides the introduction to this project and an overview of the general methodology used.

Subsequent sections summarize progress on concept development and data collection in the following areas:

- Storage of Captured CO₂—this section includes more detailed information on storing CO₂ in active oil reservoirs to enhance oil recovery (EOR) and assumptions and design basis for depleted oil and gas reservoirs, coal beds with methane capture, deep aquifers, and oceans
- Transport and Injection of Captured CO₂
- Cropland CO₂ Sequestration via Reducing Tillage
- Forestry CO₂ Sequestration
- Life Cycle Analysis Approach
- Comparing Concepts Differing in Permanence and Timing of CO₂ Sequestration

CO₂ Storage and Sink Enhancements: Developing Comparable Economics

Richard G. Rhudy (rrhudy@epri.com; 650-855-2421)
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94303-0813

Bert R. Bock (brbock@tva.gov; 256-386-3095)
David E. Nichols (denichols@tva.gov; 256-386-2489)
Tennessee Valley Authority
P.O. Box 1010
Muscle Shoals, AL 35662-1010

Abstract

One of the major difficulties in evaluating CO₂ sequestration technologies and practices, both geologic storage of captured CO₂ and storage in biological sinks, is obtaining consistent, transparent, accurate, and comparable economics. This paper reports on a project that compares the economics of major technologies and practices under development for CO₂ sequestration, including captured CO₂ storage options, such as active oil reservoirs, depleted oil and gas reservoirs, deep aquifers, coal beds, and oceans, as well as the enhancement of biological sinks such as forests and croplands. An international group of experts has been assembled to compare on a consistent basis the economics of this diverse array of CO₂ sequestration options. A summary of the results is being prepared along with a spreadsheet model to facilitate economic comparisons. The primary funding source for the project is the Department of Energy (DOE); and the Tennessee Valley Authority (TVA) and the Electric Power Research Institute (EPRI) are providing matching funds. TVA is the prime contractor and the following organizations are subcontractors: EPRI, Parsons Infrastructure and Technology, University of Tennessee, Massachusetts Institute of Technology (MIT), IEA Greenhouse Gas Programme, and SFA Pacific.

Introduction

In order to plan for potential CO₂ mitigation mandates, utilities need better information on CO₂ mitigation options, especially carbon sequestration options that involve non-utility operations. One of the major difficulties in evaluating CO₂ sequestration technologies is obtaining consistent, transparent, accurate, and comparable economics. DOE, EPRI, and TVA are jointly funding an 18-month, \$820,000 project, entitled "Economic Evaluation of CO₂ Sequestration Technologies,"

that will compare on a consistent and logical basis the economics of the major technologies and practices under development for CO₂ sequestration. Concepts to be considered include:

- CO₂ storage in active oil reservoirs, coal beds, depleted oil and gas reservoirs, deep aquifers, and oceans
- Enhanced CO₂ sinks in forests, croplands, and fertilized oceans

Objective

The objective of this project is to evaluate on a common basis the economics of a wide array of CO₂ sequestration options to facilitate utility and policy planning for implementing CO₂ mitigation options.

Project Description

An international group of experts in this area has been assembled to develop the technology/ practice designs and economic premises. TVA will be the prime for this project, responsible for overall completion of the effort. EPRI will organize efforts to select specific sequestration processes to be evaluated for captured CO₂ and will coordinate the efforts of consultants from the MIT, SFA Pacific, and the IEA Greenhouse Gas Programme to develop and refine the framework for the economic evaluations. MIT and Parsons Infrastructure and Technology will develop process designs for captured CO₂ sequestration processes and help TVA develop economic models for comparing technologies and practices. The University of Tennessee Agricultural Policy Research Center, in collaboration with TVA, will evaluate the economics of enhancing CO₂ sequestration in croplands. The IEA Greenhouse Gas Programme will develop the concept design for evaluating the ocean and forest sequestration options.

Economic Framework

Most of the cost comparisons to date have concentrated on CO₂ capture, with the assumption that CO₂ sequestration is a small part of these costs. In addition, these comparisons have used information supplied from studies of specific technologies, and the variability in costs due to variability in assumptions and lack of visibility into assumptions lessens the usefulness of the results. In the case of sequestration, virtually no comparative economic evaluations of processes have been done.

Methodologies for developing economic comparisons are generally available. They range from very detailed ± 10 percent for site-specific evaluations, where final decisions are made between options, to very general economics with little insight into the economic premises that were used to develop the economics. The latter is usually a simplification of more detailed economics for very high-level comparisons. In some cases, probability analyses are included to help evaluate risks. This usually adds significantly to the complexity of the model and the time to develop results. The model may use simplified economics to allow probability analysis without making the model too complex to run in a reasonable time.

The economic evaluations developed for this project will be between the ranges described above and will be typical of prior EPRI economics where a ± 25 to 30 percent estimate is made, with the ability to modify values to be relatively site-specific. Material balances are made, equipment lists and pricing are developed, installation costs are estimated and contingencies are estimated for project and process uncertainties. These types of evaluations are intended to be transparent, consistent, and comparable. They will be consistent with the EPRI economics of advanced power generation with CO₂ capture being developed for DOE. Probability analysis will not be included to keep the results consistent with other EPRI studies. At a later date, these economics might be parameterized to be included in the Carnegie-Mellon model being developed under another DOE project.

The economic framework will also include life cycle analysis for the various sequestration options. This means that all greenhouse gas emissions from cradle to grave will be estimated and considered in the analysis. The economic analysis will use spreadsheet models that will be flexible enough to allow a wide variation in the range of parameters to be evaluated and the sensitivity cases to be run.

Conceptual Description

The format of the spreadsheets will be EXCEL workbooks based on work regarding power generation with CO₂ capture and on other economic programs developed at EPRI for economic evaluations of emissions control processes. An input sheet will list all of the variables that can be input and the ranges that produce meaningful results. One or more sheets will contain any formulas for calculating costs and an output sheet for the results. All of the information will be transparent to a user of the spreadsheet. A write-up of the assumptions and basis for the calculations will be developed. The spreadsheet program will not be a production grade suitable for public use, since the costs of developing a version of that level were not included in our proposal. The information available as supporting documents will be sufficient to develop a commercial version at a future time.

Preliminary decisions, regarding values and ways to handle various uncertainties, made at the initial project meeting are summarized below. Members of the project decided that, in some cases, enough information for a final decision was not available and that additional information gathering would be needed to reach a final decision.

Required Amount, Pressure, and Quality of CO₂

We plan to consider a 405.4 MW (net after CO₂ capture) integrated gasification combined cycle (IGCC) plant as the production source of CO₂ (this will be the same as the recent EPRI/DOE advanced power generation economics case 3a) (1). Sensitivity cases for a PC plant and a natural gas-fired system may be considered, if sufficient resources are available. This will be a non-site-specific model using EPRI's central U.S. rates for work done in the captured CO₂ cases. For the sink cases, we will use labor rates

appropriate to the concept. For economic purposes, we will assume a 2001 start-date with overnight installation.

For the CO₂ to be transported in a pipeline, composition requirements will be the existing pipeline specification of 2200 psia, -40°F dew point, N₂<300 ppmv, O₂<40 ppmv, and Ar<10 ppmv. The base for pipeline length will be 100 km, with sensitivity cases of 0 and 300 km.

Process Scope

A life cycle analysis of greenhouse gases will be performed for each concept. However, consideration of externalities (damage estimates) will not be included.

Concepts Compared on a CO₂ Avoided Basis

Carbon dioxide capture and storage will be compared with sink enhancement on a CO₂ avoided basis. The cost of CO₂ capture and the quantities of CO₂ emissions avoided by the capture technologies will be obtained from the associated EPRI/DOE economics project¹. The cost of CO₂ storage will be estimated in this project.

Level of Development

Contingency factors will be used to account for the level of development of the processes. In setting these values, methodology in the EPRI Technical Assessment Guidelines (TAG) will be followed.

Time Period/Economic Discounting

The preliminary decision was to use a 20-year standard evaluation (the length of typical plant evaluations) and one for a longer period (thinking in terms of 100 years). For the longer period, we felt that a bit more investigation of how others handle the longer-term evaluations needed to be done to avoid picking a period that does not make sense.

For discounting costs of CO₂ storage concepts, we will use the same values (discount rate, capital carrying charge, and levelization factor) as the Neville Holt study for the captured CO₂ cases. Appropriate values will also be chosen for the sink concepts. These may be different from the ones used in the captured CO₂ cases since the value of money may be different. For the long-term period, we will add a case where the discounting is done at a zero cost of money. Time preference for CO₂ abatement will also be considered.

CO₂ Leakage Over Time

We assume that, for most of the processes of concern, the CO₂ leakage rate will be low in the time periods we will consider. We will pick a low value (probably <0.1%/year and perform a sensitivity for a higher value). We need to discuss this issue with experts in each of the concept areas to confirm the appropriate low value and to select the higher value.

Monitoring Costs

We will provide a cost allowance for monitoring. This will include a pre-check for suitability of the site; ensuring actual storage; and monitoring for leaks. This will also apply to cropland and forests. We plan to have discussions with experts in the field to finalize this value. We likely will do a sensitivity on this variable between 1 and 10 percent of total costs, if no other information is available.

Transaction Costs—Land, Rights, Etc.

We will provide an allowance for transaction costs. We plan to have discussions with experts in the field to finalize this value. We likely will do a sensitivity on this variable between 1 and 10 percent of total costs, if no other information is available.

Fuel and Electricity Costs

We will use the 2001 Energy Information Agency (EIA) Annual Energy Output (AEO) report to select fuel and electricity costs.

Value of Salable Products

We will use current values for oil and methane. For methane, we will consider either on site use or use requiring transport up to 10 miles.

Results

In mid-December 2000, the members of the project met for two days to finalize the Project Plan. During this meeting, the potential processes and concepts to be evaluated were prioritized, and the concepts were placed into three categories—(1) included, (2) may be included but more information is needed before a final decision can be made, and (3) not included due to the lack of good information at this time. Because one of the most unique aspects of this work is the comparison between storage of captured CO₂ and sink enhancement, project members felt that at least one of each type should be included. The list of concepts and their final status is presented in Table 1.

Table 1. Concepts Status

Included	Not Included
Aquifers	Ocean Fertilization
Oil Reservoirs	Mineralization
Depleted Oil and Gas Reservoirs	
Ocean Storage	
Forests	
Croplands	
Coal Beds	

In the case of ocean fertilization and mineralization, the group felt that at this time there is not enough reasonable information to develop a meaningful concept description and that these processes should not be included until more R&D is performed.

Aquifer Storage

Shown below is the preliminary block diagram for the Aquifer Storage concept. This concept is simple in application. The complexity comes from deciding on the nature of the distribution and number of wells.

Figure 1. Preliminary Block Diagram for Aquifer Storage Concept

The rationale for including the aquifer concept in the economic evaluation is summarized in Table 2 below. This concept has the largest storage capacity of all the concepts, except the ocean, and is widespread throughout the United States. In addition, it is at commercial scale, although not in the United States. Sufficient data should be available.

Table 2. Rationale for Including Aquifers in the Economic Study

Merits	Potential Challenges	Applicability	Technical Maturity	Data Availability	Industrial Acceptance	Compatibility With Power Systems
<ul style="list-style-type: none"> • Best potential CO₂ storage capacity of all geological storage options • Retention time predicted to be thousands of years • Offshore aquifers eliminate most safety concerns 	<ul style="list-style-type: none"> • Understanding risk of catastrophic or slow release of CO₂ 	<ul style="list-style-type: none"> • Ubiquitous and large, so widespread availability 	<ul style="list-style-type: none"> • Some experience of aquifer storage for chemicals, etc. • Little actual experience for this specific application 	<ul style="list-style-type: none"> • Many studies on this storage option • Specific reservoir characterization is lacking 	<ul style="list-style-type: none"> • Commercial application - CO₂ has been injected into the Utsira formation under the North Sea since August 1996, as part of the Sleipner Vest project • Accepted for materials other than CO₂ 	<ul style="list-style-type: none"> • Excellent

Oil Reservoir Storage with Enhanced Oil Recovery (EOR)

Shown below is the preliminary block diagram for the EOR storage concept.

The rationale for including the EOR concept in the economic evaluation is summarized in Table 3 below. While this concept has a more limited storage capacity and is not as widespread,

Figure 2. Preliminary Block Diagram for EOR Concept

it is likely to be an early application due to the potential for low-cost storage. It is also commercial in the United States. However, it has not been optimized for maximum CO₂ storage, and its compatibility with power systems is of some concern. Sufficient data should be available.

Table 3. Rationale for Including EOR in the Economic Study

Merits	Potential Challenges	Applicability	Technical Maturity	Data Availability	Industrial Acceptance	Compatibility With Power Systems
<ul style="list-style-type: none"> Oil by-product makes option economically attractive Not considered to involve any undue risks to man or the natural environment Injection of CO₂ done commercially today 	<ul style="list-style-type: none"> Could often be cheaper to obtain CO₂ from natural sources Global storage capacity may be limited (e.g., to 65 Gt. C) (2) For today's blowdown, reservoir operations need to store CO₂ under pressure 	<ul style="list-style-type: none"> Limited to areas where there are active oil fields 	<ul style="list-style-type: none"> EOR practiced on a significant scale for last 25 years 	<ul style="list-style-type: none"> Excellent 	<ul style="list-style-type: none"> EOR is widely used, in 1998 more than 65 oil fields in the U.S. were being injected with CO₂ Industry actively investigating the option of using captured CO₂ 	<ul style="list-style-type: none"> Oil operations require continuous supply (versus intermittent) Issues with fluctuation in the quantity of CO₂ needed over time

Depleted Oil and Gas Reservoir Storage

Shown below is the preliminary block diagram for the Depleted Oil and Gas Reservoir Storage concept.

Figure 3. Preliminary Block Diagram for Depleted Oil and Gas Reservoir Storage

The rationale for including the Depleted Oil and Gas Reservoir Storage concept in the economic evaluation is summarized in Table 4 below. This concept is similar to the EOR, except the storage location is simply used for storage without recovery of oil or gas. Since the storage location has a known integrity, it should be relatively straightforward to use. The gas reservoirs may be the easiest since gas should be depleted and the reservoir can just be repressurized. The data should be sufficient, since it is so similar to EOR.

Table 4. Rationale for Including Depleted Oil and Gas Reservoirs in the Economic Study

Merits	Potential Challenges	Applicability	Technical Maturity	Data Availability	Industrial Acceptance	Compatibility With Power Systems
<ul style="list-style-type: none">• Global storage capacity as much as 140 Gt. C for disused gas fields and 40 Gt. C for disused oil fields (3)• Reservoirs have proven containment over geological time frames• Knowledge about reservoir already exists	<ul style="list-style-type: none">• Today very few reservoirs depleted• Understanding risk of catastrophic or slow release of CO₂	<ul style="list-style-type: none">• Limited to areas where there are disused oil and gas reservoirs	<ul style="list-style-type: none">• Uses similar technology to EOR	<ul style="list-style-type: none">• Good	<ul style="list-style-type: none">• No commercial scheme involving such fields as yet exists• May be liability issues	<ul style="list-style-type: none">• May need multiple reservoirs for large power plants

Coal Bed Storage

Shown below is a preliminary block diagram for the Coal Bed Storage concept.

Figure 4. Preliminary Block Diagram for Coal Bed Storage Concept

The rationale for including the Coal Bed Storage concept in the economic evaluation is summarized in Table 5 below. While the data is limited, CH₄ by-product production credits and significant coal deposits make a good argument for inclusion. Data availability is limited.

Table 5. Rationale for Including Coal Bed Storage in the Economic Study

Merits	Potential Challenges	Applicability	Technical Maturity	Data Availability	Industrial Acceptance	Compatibility With Power Systems
<ul style="list-style-type: none"> • CH₄ by-product makes option economically attractive • CO₂ strongly sequestered by adsorption on coal matrix • Worldwide large coal deposits means potentially large CO₂ storage capacity 	<ul style="list-style-type: none"> • Enhanced gas recovery (EGR) methods for coal bed CH₄ exploitation require further refinement 	<ul style="list-style-type: none"> • Unclear as to how many types of coal formations will be practical to use for coal bed CH₄ production 	<ul style="list-style-type: none"> • Injection of CO₂ into coal beds already used to enhance CH₄ recovery, although process is still at an early stage of development 	<ul style="list-style-type: none"> • Limited 	<ul style="list-style-type: none"> • Well accepted 	<ul style="list-style-type: none"> • Could be used to develop a zero greenhouse gas emissions power plant fueled by coalbed CH₄, where waste CO₂ produced by plant is injected into coalbed CH₄ reservoirs to produce more CH₄

Ocean Storage

Shown below is a preliminary block diagram for the Ocean Storage concept.

Figure 5. Preliminary Block Diagram for Ocean Storage Concept

The rationale for including the Ocean Storage concept in the economic evaluation is summarized in Table 6 below. The ocean has the largest storage capacity of any of the concepts, and much work has been done to study ways to store CO₂ in the ocean. Sufficient data should be available.

Table 6. Rationale for Including Ocean Storage in the Economic Study

Merits	Potential Challenges	Applicability	Technical Maturity	Data Availability	Industrial Acceptance	Compatibility With Power Systems
<ul style="list-style-type: none"> • Largest potential sink for CO₂, storage capacity estimated to be upwards of 1000 Gt. C (4) • Leaks do not pose safety issues 	<ul style="list-style-type: none"> • Could have a negative impact on local marine environment • Significant legal and jurisdictional issues to be overcome • Negatively perceived by non governmental organizations (NGOs) • Retention time, on the order of hundreds of years, less than for underground storage 	<ul style="list-style-type: none"> • Best suited to countries situated adjacent to ocean trenches and that do not have access to suitable underground reservoirs, for example Japan • Populated areas are near coastlines 	<ul style="list-style-type: none"> • Much experience from offshore exploration/production is applicable 	<ul style="list-style-type: none"> • Modest 	<ul style="list-style-type: none"> • Not well perceived compared to geological storage options • Field experiment to take place off the coast of Hawaii in 2001, this should help to reduce some of the uncertainties 	<ul style="list-style-type: none"> • Excellent for plants situated on coastline

Forest Sink Enhancement

Shown below is a preliminary block diagram for the Forest Sink Enhancement concept.

Figure 6. Preliminary Block Diagram for Forest Storage Concept

The rationale for including the Forest Sink Enhancement concept in the economic evaluation is summarized in Table 7 below. Forests are generally considered the lowest-cost storage option, and a great deal of work has been done on them. This is the basic sink comparison to be made with the captured storage concept. A number of concerns still remain, and matching the economics will be difficult. Sufficient data should be available.

Table 7. Rationale for Including Forest Sinks in the Economic Study

Merits	Potential Challenges	Applicability	Technical Maturity	Data Availability	Industrial Acceptance	Compatibility with power systems
<ul style="list-style-type: none"> • Low cost • Significant forest available • Provides funding and employment in rural areas and developing countries. • Preservation of biodiversity 	<ul style="list-style-type: none"> • Monitoring and verification of carbon storage • Opportunities for fraud • "Leakage" minimization • Short-term storage • Risks of forest loss through fires, pests and social factors 	<ul style="list-style-type: none"> • Particularly applicable to areas of low population with few other land use options • Changes to albedo may make forests less effective in high latitudes • Global capacity limited and costs increase substantially as less favorable sites are used 	<ul style="list-style-type: none"> • Forestry is technically mature • Land owners and farmers need to be educated on merits of forestry for carbon storage • Monitoring and verification services offered but further developments would be beneficial to increase accuracy and reduce costs 	<ul style="list-style-type: none"> • Good • Current projects small and may not be representative of large schemes • Current large-scale projects are mainly deforestation avoidance 	<ul style="list-style-type: none"> • Still being debated at the COP 6 meeting • Considered the easy, low-cost option • Some companies already buying forestry carbon credits • Still concerns over "leakage" and risks 	<ul style="list-style-type: none"> • Applicable to all power systems since there is no direct link to the power plant

Cropland Sink Enhancement

Shown below is a preliminary block diagram for the Cropland Sink Enhancement concept. The cropland concept involves enhancing soil carbon sequestration by switching from conventional- to conservation-tillage systems and improving residue management. Conservation-tillage systems use less intensive tillage, often no tillage, and leave at least 30 percent of the crop residues on the soil surface. Conservation-tillage systems also sometimes include a winter cover crop that remains on the soil surface to reduce soil erosion. The winter cover crop is not harvested and adds additional crop residue to soil organic matter.

General parameters for estimating the net cost of switching to conservation-tillage systems are presented in the block diagram below. The net cost of switching to conservation-tillage systems is the added cost of tillage-system inputs, plus or minus the change in revenue from changes in crop yield.

General parameters for estimating the additional CO₂ sequestered in soil organic matter are also presented in the block diagram. These parameters are (1) the increase in crop residue carbon added to soil organic matter, (2) the reduced rate of soil organic matter decomposition to CO₂, and (3) the reduced soil erosion and the associated reduction of CO₂ emitted from eroded soil.

Figure 7. Preliminary Block Diagram for Cropland Sink Concept

The rationale for including the Cropland Sink Enhancement concept in the economic evaluation is summarized in Table 8 below. The cropland component of this project will estimate added costs of converting from conventional-tillage systems to conservation-tillage systems that sequester additional carbon in soil organic matter. Increased adoption of conservation-tillage systems and improved residue management accounts for about one-half of the potential for reducing greenhouse (GHG) emissions from U.S. croplands

(5). The remaining one-half of the potential for reducing GHG emissions from U.S. croplands is highly fragmented and beyond the scope and resources of this project.

In conventional-tillage systems, soil is plowed or otherwise thoroughly tilled and all of the crop residues are mixed with soil. In contrast, conservation-tillage systems involve less intensive tillage (often no tillage), leave 30 percent or more of the crop residues on the soil surface, and sequester additional carbon in soil organic matter that otherwise would be emitted to the atmosphere as CO₂. In addition to sequestering more carbon, conservation-tillage systems also have lower emissions associated with production and use of tillage-system inputs, dramatically reduce soil erosion and CO₂ emissions from eroded soil, improve soil quality, and conserve soil water by reducing water runoff and evaporation from the soil.

Table 8. Rationale for Including Cropland Sinks in the Economic Study

Merits	Potential Challenges	Applicability	Technical Maturity	Data Availability	Industrial Acceptance	Compatibility With Power Systems
<ul style="list-style-type: none"> • Relatively low projected cost/ton of CO₂ • Collateral benefits of conservation tillage—improved soil quality, reduced soil erosion, improved water-use efficiency, improved crop productivity where well adapted 	<ul style="list-style-type: none"> • Possible need for periodic use of conventional tillage to maintain crop productivity, resulting in partial loss of sequestered CO₂ • Possible reversion to conventional tillage due to changes in land ownership • Resistance to including biological sinks in GHG policies • Poorly developed infrastructure for CO₂ credits and markets • Good base for infrastructure 	<ul style="list-style-type: none"> • Excellent in well-drained soils, water deficient cropping systems, and highly erosive soils • Moderately good in most other cropping systems 	<ul style="list-style-type: none"> • Conservation tillage systems under development since early 1970s • ~35% adoption achieved to date in U.S. • Technology ready for rapid adoption, given additional economic incentives 	<ul style="list-style-type: none"> • Good for costs of tillage systems • Moderately good for CO₂ sequestration rates • Lacking for equilibrium levels of sequestered carbon and time to equilibrium • Good for CO₂ emissions factors associated with tillage-system inputs 	<ul style="list-style-type: none"> • Generally good farmer acceptance because of collateral benefits • Somewhat greater economic risk to farmers • May require moderate adoption incentives to achieve rapid additional adoption 	<ul style="list-style-type: none"> • Good compatibility via combining farm-level CO₂ sequestration credits into bundles of sufficient size to match power project needs

Future Activities

The schedule for the project is shown below in Figure 7. The project will run through the end of April in 2002. The spreadsheet development will run concurrently with the data collection effort, since the framework can be built and then populated with the information from the data collection effort.

Figure 7. Project Schedule

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2.0 Storage of Captured CO₂

2.1 Required Amount, Pressure, and Quality of CO₂

A nominal 500 MW gross integrated gasification combined cycle (IGCC) plant operating at an 80 percent capacity factor will be utilized as the production source of CO₂. This will be based on the DOE/Neville Holt's recent study on the "Evaluation of Innovative Fossil Fuel Power Plants with CO₂ Removal."¹ A sensitivity to a PC plant and a natural gas-fired system may be considered if sufficient resources are available. Table 1 shows a summary of output parameters taken from the DOE/Neville Holt report for each of these technologies. The CO₂ source for the baseline evaluations will be from Case 3a, 7,389 tonnes per day of CO₂.

Table 1
Summary of Output Parameters

Technology	Neville Holt Case Number	Thermal Input, HHV (10⁶ Btu/hr)	Gross MW	Net MW	Efficiency, % HHV
Supercritical PC	7a	3,891	402	329	28.9
IGCC	3a	3,723	490	404	37.0
NGCC-H Turbine	1b	2,448	343	311	43.3

Technology	CO₂ Recovered (ton per day)	CO₂ Recovered (tonne per day)	CO₂ Recovered (million scf/day)	COE @ 80% CF (mills/kWh)	Cost of CO₂ Recovered (\$ per tonne @ 80% CF)
Supercritical PC	8,525	7,734	139	74.4	30.0
IGCC	8,145	7,389	133	56.4	14.8
NGCC-H Turbine	3,105	2,817	51	48.1	48.2

This study will be a non-site-specific model using EPRI central U.S. rates for work done in the captured CO₂ cases. For composition requirements we plan to use the existing pipeline specification (2,200 psia, -40°C (-40°F) dew point, N₂<300 ppmv, O₂<40 ppmv, Ar<10 ppmv) as the quality of the CO₂. The DOE/Neville Holt study is consistent with this except for the CO₂ pressure. Their study was based on compressing the CO₂ to 1,200 psia, although a sensitivity study at 2,200 psia was done. This study will include additional compression to 2,200 psia. Pipeline distance to the sequestration sites will be 62 miles (100 kilometers).

2.2 Technologies Evaluated

During the kickoff meeting, the potential processes and concepts to be evaluated were prioritized. The concepts were placed into three categories: included, may be included but more information is needed before a final decision can be made, and those that will not be included due to the lack of good information at this time. Because one of the unique aspects of this work is the comparison between storage of captured CO₂ and sink enhancement, members of the project felt that at least one of each type should be included. The list of concepts and their status is shown in Table 2.

In the case of ocean fertilization, the group determined that there was not enough reasonable information on the process at this time to develop a meaningful concept description and that it should not be included until more R&D is performed.

Table 2
Concepts Status

Included	May Be Included	Not Included
Enhanced Oil Recovery	Enhanced Coalbed Methane	Ocean Fertilization
Depleted Oil and Gas Reservoirs	Mineralization	
Aquifer Storage		
Ocean Storage		
Forests		
Croplands		

In the case of mineralization, the group felt that the R&D is still in its infancy; however, there may be enough information available after the latest information from the developers of these concepts is acquired. The final decision on inclusion will be made after all available information is collected.

Initially, the same was thought to be true for coalbed methane. However, a recent IEA Greenhouse Gas R&D Programme Report² assessed the potential of enhanced coalbed methane recovery with CO₂ sequestration and concluded, “Injection of carbon dioxide into deep coal seams has the potential to enhance coalbed methane recovery, while simultaneously sequestering carbon dioxide. Analysis of production operations from the world’s first carbon-dioxide-enhanced coalbed methane demonstration plant, in the San Juan Basin, indicates that the process is technically and economically feasible. A recent pilot scheme in Alberta, Canada, should also help to confirm the technical and economic data of this process.” Thus, while there is still uncertainty about the effectiveness of CO₂ in enhancing the recovery of coalbed methane, the potential is such that it will be included in the study.

2.3 Design Basis: Geologic and Ocean Storage Options

Two key areas for all the geologic options are the injection/production wells and field equipment/production operations. Two annual surveys, “Joint Association Survey on Drilling Costs”³ and “Costs and Indices for Domestic Field Equipment and Production Operations,”⁴ have for many years tracked costs for drilling and operating domestic oil and gas fields. Depth, regions, well type, and production rate disaggregate these costs. Our options will be tied as closely as possible to these surveys to provide both up-to-date costs and indices that measure the increase or decrease in costs from year to year.

The third key area for all the options is the pipeline used to transport the captured CO₂. A cost model for transport of CO₂, developed by the MIT Energy Laboratory,⁵ will be

utilized. Modifications to include additional compression or pumping stations will be included as necessary.

For each option, a baseline conceptual design will be generated based on the assumptions discussed below. From the baseline conceptual design, capital, O&M costs and an economic analysis with several figure of merits will be developed in a spreadsheet format. These will then be used to develop sensitivity analyses and life cycle analyses, again in a spreadsheet format.

2.4 Enhanced Oil Recovery

A miscible CO₂ gas flood of an oil reservoir works because the injected gas becomes miscible, or becomes one liquid phase, with the oil, and helps the oil move through the rock reservoirs and up and out the wells. CO₂ is continually added to an oil reservoir by being compressed and pushed in, and when it is produced back out with the enhanced oil, it is recaptured and reinjected along with new CO₂ and continually recycled until as much enhanced oil has been produced as possible. Millennium Energy Inc. owns an interest in a mature CO₂ flood of an oil reservoir in West Texas, which started in 1983. The field now adds 10 million cubic feet per day of new CO₂ (piped in from New Mexico) to 30 million cubic feet per day of CO₂ being recycled from the enhanced oil production.⁶

Typically miscible floods (hopefully) produce each barrel of oil by adding only 5,000 to 10,000 cubic feet of CO₂ to the reservoir via the stream of cycling gas. A rule of thumb typically used in west Texas is 6,000 cubic feet per barrel of oil.⁷ After many years of production when the returns of oil have diminished or the amount of recycled CO₂ has increased to the point of being uneconomic, the flood is shut in. There would be 6,000 cubic feet of CO₂ down in the reservoir for every enhanced barrel of oil produced during the life of the project.

The Costs and Indices for Domestic Field Equipment and Production Operations report⁴ includes a scenario for secondary oil recovery based on water flooding. Costs and indices for additional secondary oil recovery equipment and its operation were calculated for a 10-well lease producing 90 barrels per day (bbl/day) per well with well depths of 2,000, 4,000, and 8,000 feet in west Texas. Eleven water injection wells were used for each 10-well lease.

Since the average oil production per well in the United States in 1999 was 10.7 bbl/day⁸, the 90 bbl/day used for this EIA report is probably not typical, even with Enhanced Oil Recovery (EOR). Since we are assuming a constant CO₂ input and oil production, the production per well determines the number of wells needed.

The EIA scenario was modified for CO₂ flooding and used as the basis for field equipment and production operations costs. However, it was assumed that a more typical production per well would be 20 bbl/day. Table 3 summarizes the major assumptions used for the enhanced oil recovery option in the conceptual design.

Table 3

New CO₂ (tonne per day)	New CO₂ (million scf/d)	CO₂ Effectiveness (scf/bbl)	Oil Production (bbl/day/well)	Oil Wells (Number)	Oil Production (bbl/day)	CO₂ Wells (per oil well)
7,389	133	6,000	20	1108	22,152	1.1
CO₂ Wells (Number)	New CO₂ (scf/day/well)	Recycled CO₂ (scf/day/well)	Average Recycle Ratio	Total CO₂ (scf/day/well)	Injection Pressure (psi)	Depth (feet)
1218	109,091	163,636	1.5	272,727	1,200	4,000

Based on 7,389 tonne per day from the IGCC plant and an effectiveness of 6,000 scf/bbl, 1,108 production wells could be serviced, requiring 1,218 injection wells. At 20 bbl/day per well, over 22,000 bbl/day of oil would be produced. The recycle ratio would rise to 3.0 over the life of the field, thus assuring a constant oil production rate of 20 bbl/day. The recycle system equipment, primarily for compression of the CO₂, would be sized for a recycle ratio of 3.0 while the O&M power costs would be based on an average recycle ratio of 1.5. Power required for CO₂ recycle will be based on the cost of electricity (COE) of the IGCC power plant. For life cycle analyses, any power use in the sequestration process will be charged against the IGCC power production. A typical well depth of 4,000 feet was used with sensitivities at 2,000 and 8,000.

2.4.1 Process Description

The source of CO₂ for the Enhanced Oil Recovery (EOR) case is taken from Case 3A of the DOE/EPRI Report on CO₂ removal from fossil fuel power plants¹. This case is used for the design basis since potential CO₂ sources from a coal-based power plant would most probably be associated with an IGCC plant. CO₂ recovery from IGCC is most economical because of the CO₂ concentration in syngas at a high partial pressure, enabling the use of conventional recovery processes. Figure 1 is a block flow diagram, indicating the overall flow and distribution of CO₂ from the IGCC plant to the EOR field. CO₂ leaving the plant is fed to an additional stage of compression and dehydration to reach pipeline pressure. The pipeline transports the CO₂ to the EOR field a distance of 100 km, where it is mixed with recycled CO₂ and injected into the EOR CO₂ wells. Oil from the EOR wells is separated from water and CO₂ at the surface. CO₂ is compressed and dehydrated to be recycled and added to fresh incoming CO₂.

2.4.2 Source of CO₂

The baseline IGCC plant produces two streams of CO₂ from the double-stage Selexol acid gas removal process. One stream is at 50 psia, while the second stream produced at 15 psia is boosted to 50 psia. The combined 50 psia CO₂ streams are further compressed and dehydrated in a multi-stage, intercooled compressor to 1,200 psia.

The amount of pure CO₂ recovered from the IGCC plant is 7,389 tonne per day.

2.4.3 CO₂ Pumping for Pipeline Entry

IGCC Case 3A included a sensitivity step of adding an additional stage on to the compressor to increase the CO₂ pressure at the plant fence to 2,200 psia. This requires an additional power penalty of 2,650 kW.

Referring to Figure 2, the CO₂ at 1,200 psia and 40°C (105°F) is above and to the liquid side of the critical point 31.1°C (88°F) and 73.0 bar (1,073 psia) in the liquid state. By increasing pressure to 2,200 psia and 83°C (100°F) or less, the pipeline pressure can drop to about 1,500 psia before recompression, and the CO₂ mass is ensured of retaining flow properties approximating a liquid.

Figure 2. Carbon dioxide pressure enthalpy diagram.

The CO₂ stream is dried to a -40° C (-40°F) dew point and contains N₂<300 ppmv, O₂<40 ppmv, and Ar<10 ppmv.

2.4.4 CO₂ Pipeline

The CO₂ pipeline is designed to carry the full load of CO₂ for the 100 km in a safe and reliable manner. The Design Basis for the pipeline is shown in Table 4.

Table 4
Pipeline Design Basis

Maximum CO ₂ Flow Rate	7,389 tonne/day (2,700,000 tonne/year)
CO ₂ Pressure at Plant Gate	82 bar (1,207 psig)
Pipeline Inlet Pressure	150 bar (2,200 psig)
Power to Achieve Inlet Pressure	2,650 kW
Inlet Boost Compressor Cost	\$3,250,000
Pipeline Length	100 km (62 miles)
Pipeline Temperature	25°C (77°F)
Pressure Drop per Unit Length	25 Pa/m (0.0011 psi/ft) (600 psi/100 mi)
Minimum Outlet Pressure	102 bar (1,500 psig)

The M.I.T. Pipeline Cost Model was utilized to determine pipelines diameter, pressure drop, and installed cost. The precise flow of 2.7 Mtonne/year resulted in the results shown in Table 5.

Table 5
Pipeline Results

Initial CO ₂ Pressure	150 bar (2,200 psig)
Internal Pipe Diameter	0.323 meter (12.72 inches)
Total Pressure Drop	24.94 bar (367 psi)
Line Pressure at Terminal	125 bar (1,838 psig)

The pipeline design conforms to U.S. Department of Transportation (DOT) Codes 49 CFR 195, Transportation of Hazardous Liquids by Pipeline and 49 CFR 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards.

Due to the high pressure associated with CO₂ transport, the pipeline is constructed of API 5LX-X70 high-yield steel pipe, having a yield strength of 70,000 psi. This serves to reduce the tonnage of steel purchased. Prior experience at commercial CO₂ pipelines has shown that, when adequately dehydrated, CO₂ is not corrosive to steel. However, where

costs are not prohibitive, stainless steel and protective coatings are utilized. The entire length of the pipeline is wrapped and protected with galvanic measures. The M.I.T. Pipeline Cost Model was used to determine the construction and operating cost of the pipeline. Table 6 shows the results.

Table 6
Pipeline Design

Pipeline Length	100 km (62 miles)
Nominal Pipe Diameter	14 inches
Wall Thickness	12.7 mm (0.5 inch)
Pipe Inside Diameter	0.330 meter (13.0 inches)
Recompression Stations	None
Pipeline Construction Cost	\$26,565,000
Annual Operating Costs @ \$5,000/mile	\$310,000

2.4.5 EOR Field--10 Producing Wells Module

The EOR field consists of a distribution and injection system, which serves several purposes:

- Receive CO₂ from the pipeline terminal and distribute it to the EOR CO₂ injection wells.
- Gather oil from the EOR production wells and deliver it to a central gas/liquid separator.
- Compress separated CO₂ and mix with pipeline CO₂ for injection into EOR CO₂ injection wells.

Our design was tied as closely as possible to the EIA Cost Report for Equipment and Production Operations⁴ in order to make use of their data. Their report marks the continuation of the EIA series on equipment and operating costs and cost indices for oil and gas leases. In addition to cost comparisons within the petroleum industry, the data reported there are often used to assess the economic effects of specific plans and policies relating to the industry. Standardization of the data used has evolved during the past 23 years. Improved methods for measuring various contractor costs were used and applied to previous estimates.

The costs and cost indices provided in this report are for representative lease operations with equipment and operating procedures designed by EIA staff engineers for representative 10-well oil leases producing by artificial lift or 1 flowing well per gas lease. For secondary oil recovery, each lease had 10 producing wells, 11 injection wells, and 1 disposal well. The design criteria took into account the predominant methods of operation in each region. Individual items of equipment were priced by using price lists

and by communication with the manufacturer or supplier of the item in each region. All costs presented in their report are current to their year and not adjusted for inflation.

Freight costs and installation costs were determined based on regional rates. These costs were summed for each category of equipment. For example, the category listed as “pumping equipment” for a rod pump system includes:

- A pumping unit
- Additional counter-weights
- Crank guards
- Belt guards, V-belts and sheaves
- Freight costs
- Installation costs

The additional lease equipment costs and indices associated with secondary oil recovery from depths of 2,000, 4,000, and 8,000 feet in west Texas were reported. This region was the focus of a substantial part of the early secondary recovery work in the country, and the differences between primary and secondary costs are presumed to be similar to those in other regions. The method used in the EIA report is water flooding. This case was modified for miscible (CO₂) flooding. Conversion of primary oil producing leases to secondary recovery (CO₂ or miscible flooding) involves:

- Drilling and equipping of 11 injection wells
- Installation of CO₂ distribution and recycle systems
- High-pressure injection equipment and related piping
- Replacement of selected production facilities

The EIA treats secondary oil production as modules consisting of 10 producing wells and 11 injection wells. Our module design is consistent with the EIA modular approach.

The key component of the EOR field is the recycle compressor, being a large energy user and requiring a large capital investment. For a 10/11 well module, the amount of CO₂ handled is based on the total number of wells and the amount of CO₂ per well. The compressor use is initially minimal, but by 20 years of operation, it is assumed that the rate of CO₂ reaching the surface with the EOR oil production will be equivalent to three times the rate of new CO₂ injected. Table 7 indicates the rationale for determining the recycle compressor and modular field design.

Table 7
The Recycle Compressor and Modular Field Design

Maximum New CO ₂ Rate	133 MMscfd
CO ₂ Effectiveness	6,000 scf/barrel
Oil Production	22,167 barrels/day
Oil Production per Well	20 barrels/day/well
Total Production Wells	1,108 production wells
Total Injection Wells	1,218 injection wells
New CO ₂ per Injection Well	109,194 scfd/well
Number of 10/11 Well Modules	111
New CO ₂ per 10/11 Well Module	1.201 MMscfd
Recycled CO ₂ @ 3 x Recycle Ratio	3.603 MMscfd
Suction Pressure	1 bar (14.7 psia)
Discharge Pressure	81.6 bar (1,200 psia)

The compressor is sized to handle all of the CO₂, which is recycled in the 10/11 well module. Table 8 illustrates the compressor features:

Table 8
Recycle Compressor Parameters

Maximum CO ₂ to be Compressed	3.603 MMscfd
Compressor Type	Reciprocating
Compressor Displacement	2,500 cfm
Overall Compression Ratio	81.6
Number of Stages	5
Horsepower per MMscfd	265.5
Connected Horsepower	1,000
Power Consumption per MMscfd	198 kW/MMscfd
Maximum Power Consumption	713 kW
Capital Cost per Compressor	\$1,000,000
Total Compressor Cost (111 Modules)	\$111,000,000

2.4.6 Modular Field Description

After oil is brought to the surface, small pipelines called flow lines carry it to a part of the production site known as the tank battery. In addition to storage tanks, the tank battery contains equipment for preparing the oil before further distribution. The fluid coming out of nearly all wells is actually a mixture of oil, gas (in this case CO₂), salt water, and sediment. First, any CO₂ present is separated from the oil and water, recycled and reinjected to help maintain reservoir pressure and thereby production. Separation of the remaining mixture is accomplished in special tanks where the settling process separates water and oil, or it may be assisted by special equipment such as a heater treater.

Testing of the oil to determine its properties is conducted at the well site by taking samples of oil from the storage tanks. Oil volumes today are measured with Lease Automatic Custody Transfer facilities (LACT's), which do most of the measuring, sampling, and testing without human intervention. Oil that has been completely prepared is stored in tanks at the well site until it is transported to the refinery.

The modular enhanced oil recovery (EOR) field consists of 10 producing wells and 11 CO₂ injection wells. The wells are nominally 4,000 feet deep. The 10 producing wells are supported with a battery of lease equipment comprised of the following:

Table 9
Lease Equipment

Equipment Description	Specification	Quantity
Tubing	2.375 inch, Grade J-55	40,000 feet
Sucker Rod	API Class K	40,000 feet
Pump Rod	API type RWBC	10
Pumping Unit	API Size M160D 173-74 12 hp	10
Oil Flowline	2.375 inch, PVC	16,000 feet
Manifold	With 10 valves (2 inch 3-way)	1
Production Separator	Vertical, 30 inch x 10 feet 300 barrels per day 4.0 MMscfd gas	1
Test Separator	1.0 barrel per day	1
Oil Storage Tank	2,000 barrel	1
Water Disposal Pump	Quintuplex, 1,000 psi 20 hp	1
Water Disposal Line	2.375 inch, 2,500 psi yield	2,000 feet
LACT Unit	500 barrels per day	1

Conversion of primary oil producing leases to secondary recovery with CO₂ involves:

- Drilling and equipping of 11 injection wells.
- Installation of CO₂ distribution and recycle systems.
- High-pressure injection equipment and related piping.
- Replacement of selected production facilities to accommodate increased production.

The capital costs for the 10/11 well EOR module based on the EIA Report are as follows:

Table 10
Capital Costs

Recycle Compressor	\$1,000,000
Injection Plant Confines	\$113,600
Distribution Lines	\$77,200
Header	\$61,100
Electrical Service	\$97,400
Production Equipment Upgrades	\$559,100
Injection Wells (11)	\$2,351,600
Total Field Capital Cost for EOR	\$4,260,000

Average Annual Operating Costs for the 10/11 EOR module are:

Table 11
Operating Costs

Pumping and Field Power @ 220 kW	1,927 MWh per year
Recycle Compressor Power @ 357 kW (average rate)	3,127 MWh per year
Normal Daily Expense	\$130,900
Surface Maintenance, Repair	\$95,300
Subsurface Maintenance, Repair	\$82,600

2.4.7 Summary of Capital and Operating Costs

Table 12 shows a summary of the capital and O&M costs for the sequestration system. Power costs were based on the COE of the IGCC power plant of 56.4 mills per kWh. These costs are representative of the total plant cost level of the EPRI TAG and do not capture all the total capital requirement costs.

Table 12
Capital and O&M Cost Summary

Capital and O&M Cost Summary for EOR

EOR Capital Costs

Plant Compression to Pipeline Specs

Equipment	\$3,250,000
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Pipeline

Pipeline	\$26,565,000
Pumping Stations	

Incremental Equipment Costs for EOR Producing from 4,000 feet

1108 Production Wells	
1218 Injection Wells	

10 Production Wells	
11 Injection Wells	

Injection Equipment Including Recycle Equipment	\$149,447,431	\$1,349,300
Producing Equipment	\$61,925,487	\$559,100
Injection Wells	\$260,461,410	\$2,351,600

Total Plant Cost	\$501,649,327	\$4,260,000
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EOR Operating & Maintenance Costs

Plant Compression	2,650 kW	\$1,047,416
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Pipeline O&M	\$310,000
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Direct Annual Operating Costs for EOR Producing from 4,000 feet

1108 Production Wells	
1218 Injection Wells	

10 Production Wells	
11 Injection Wells	

Normal Daily Expenses	\$14,498,383	\$130,900
Power	\$31,574,680	\$285,075
Surface Maintenance, Repair & Services	\$10,555,355	\$95,300
Subsurface Maintenance, Repair & Services	\$9,148,713	\$82,600

Total O&M	\$67,134,547
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2.4.8 Cost of Sequestering Summary

To get an idea of where we stand, certain simplifying assumptions were made in order to calculate a cost of sequestration. A capital charge of 15 percent was assumed, the cost of CO₂ was taken as the cost of CO₂ recovery for the power plant, and an oil credit of \$18.64 per barrel was assumed. This was based on the average, domestic, first purchase price (also known as the wellhead price) for the past twenty years of \$24.85 in 1999 dollars. It was assumed that a 25 percent royalty would be paid for a net credit of \$18.64 per barrel. Table 13 shows the results of these calculations.

Table 13
Cost of Sequestration Summary

Total O&M			\$67,134,547
Capital Charge		15%	\$75,247,399
CO₂ Cost of Recovery, (\$/tonne)		\$14.80	\$39,915,378
Oil Credit, \$/bbl	\$24.85	(\$18.64)	(\$150,692,089)
Total Cost			\$31,605,235
Costs per tonne CO₂			\$11.72
Costs per bbl of Oil			\$22.55
Costs per million Btu			\$3.58

2.4.9 Sensitivities

Figure 3

Figure 4

2.5 Design Assumptions for Other Storage-of-Captured-CO₂ Concepts

The assumptions and design basis for (1) Enhanced Coal Bed Methane, (2) Depleted Oil and Gas Reservoirs, (3) Aquifer Storage, and (4) Ocean Storage are below. Data collection is proceeding for these concepts.

<i>EVALUATION OF CO₂ SEQUESTRATION TECHNOLOGIES</i> Assumptions and Bases of Design						
Enhanced Coal Bed Methane						
New CO ₂ (tonne per day)	New CO ₂ (million scf/d)	CO ₂ Effectiveness (scf CO ₂ /scf CBM)	CBM Production (scf/day/well)	CBM Wells (Number)	CO ₂ Wells (per CBM well)	CO ₂ Wells (Number)
7,389	133	2	500,000	133	4	532
New CO ₂ (scf/day/well)	CBM Production (1,000 scf/day)	Recycled CO ₂ (scf/day/well)	Recycle Ratio	Total CO ₂ (scf/day/well)	Injection Pressure (psi)	Depth (feet)
250,000	66,456	0	0	250,000	1,200	2,000

<i>EVALUATION OF CO₂ SEQUESTRATION TECHNOLOGIES</i> Assumptions and Bases of Design						
Depleted Oil or Gas Reservoirs						
New CO ₂ (tonne per day)	New CO ₂ (million scf/d)	CO ₂ Wells (Number)	New CO ₂ (scf/day/well)	Injection Pressure (psi)	Depth (feet)	
7,389	133	133	1,000,000	1,200	4,000	

EVALUATION OF CO₂ SEQUESTRATION TECHNOLOGIES **Assumptions and Bases of Design**

Aquifer Storage

New CO ₂ (tonne per day)	New CO ₂ (million scf/d)	CO ₂ Wells (Number)	New CO ₂ (scf/day/well)	Injection Pressure (psi)	Depth (feet)
7,389	133	3	50,000,000	1,200	4,000

EVALUATION OF CO₂ SEQUESTRATION TECHNOLOGIES **Assumptions and Bases of Design**

Ocean Storage

New CO ₂ (tonne per day)	New CO ₂ (million scf/d)	CO ₂ Pipeline (Diameter, inches)	CO ₂ Pipeline (length, miles)	Depth (feet)
22,167	399	18	62	6,600

2.6 References

1. Evaluation of Innovative Fossil Fuel Power Plants with CO₂ Removal,” EPRI Report No. 1000316, Interim Report, December 2000, Cosponsors: U.S. Department of Energy/Office of Fossil Energy and U.S. Department of Energy/NETL, EPRI Project Manager N. A. H. Holt.
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7. Personal communication with Dale Simbeck, Kickoff meeting, December 11-12, 2000.
8. “Energy in the United States: A Brief History and Current Trends,” <http://www.eia.doe.gov/emeu/aer/eh1999/eh1999.html>

3.0 Transport and Injection of Captured CO₂

The section is an overview of models to be used for estimating the cost of transporting CO₂ in overland and subsea pipelines. These models include special considerations for CO₂ injection into oceans, aquifers, and hydrocarbon reservoirs.

CO₂ Pipeline Transport Model Inputs

Parameter	Units	Default
CO ₂ mass flow rate	Mt/yr	-
Initial pressure	bar	150
Pressure drop per unit length	Pa/m	25
Temperature	°C	25
Roughness	ft	0.00015
O&M	\$/yr/mi	5,000
Capital charge rate	%/yr	16

CO₂ Pipeline Transport Model Output - Diameter

CO₂ Pipeline Transport Model – Cost Data (\$) for Natural Gas Pipelines

CO₂ Pipeline Transport Model – Cost Data (%) for Natural Gas Pipelines

CO₂ Pipeline Transport Model – Capital Cost Correlation

Sources: Oil and Gas Journal,
Nov 30, 1990 and
Aug 31, 1998

Total Cost of Natural Gas Pipeline Land Construction Data
1989-1998

CO₂ Pipeline Transport Model Output – Capital Cost

CO₂ Pipeline Transport Model Output – Total Annual Cost

Overland CO₂ Pipeline Transport Model – Case Studies

STUDY	REFERENCE
Weyburn	Hattenbach, R.P., M. Wilson and K.R. Brown, "Capture of carbon dioxide from coal combustion and its utilization for enhanced oil recovery," In <i>Greenhouse Gas Control Technologies</i> P. Riemer, B. Eliasson and A. Wokaun, Eds. Elsevier Science Ltd., 1999, pp. 217-221.
IEA aquifer	Ormerod, W., "The disposal of carbon dioxide from fossil fuel fired power stations," IEA Greenhouse R&D Programme, Cheltenham. Tech. Rep. IEAGHG/SR3, Jun. 1994.
IEA depleted reservoir	Ormerod, W., "The disposal of carbon dioxide from fossil fuel fired power stations," IEA Greenhouse R&D Programme, Cheltenham. Tech. Rep. IEAGHG/SR3, Jun. 1994.
British Coal	Summerfield, I.R., S.H. Goldthorpe, N. Williams and A. Sheikh, "Costs of CO ₂ disposal options," <i>Energy Convers. Mgmt</i> , vol. 34, no. 9-11, pp. 1105-1112, 1993.

Overland CO₂ Pipeline Transport Model – Pipeline Characteristics in Case Studies

Study	CO ₂ flow rate (Mt/yr)	Initial CO ₂ pressure (bar)	Diameter (m)	Length (km)	Recompression station included
Weyburn	2.00	170.0	0.305	127.3	No
IEA aquifer	3.90	208	0.400	30.0	No
IEA depleted reservoir	3.16	110.0	0.400	50.0	No
British Coal	3.63	136.0	0.350	425	Yes

Overland CO₂ Pipeline Transport Model – Diameter Comparison

CO₂ Pipeline Transport – Design Input

Parameter	Units	Base Case	300 km Case
CO ₂ flow rate	t/d	7,389	
	Mt/yr	2.70	
Plant capacity factor		0.8	
Initial pressure of CO ₂	psia	2,200	
	bar	152	
Outlet pressure of CO ₂	psia	1,500	
	bar	103	
Pressure drop per unit length	Pa/m	48	16
Temperature	°C	25	
Pipeline length	km	100	300
Capital charge rate	%/yr	15	

CO₂ Pipeline Transport – Design Output

Parameter	Units	Base Case	300 km Case
Pipe diameter	m	0.284	0.352
Pipeline capital cost	\$M	22.7	84.4
Pipeline O&M cost	\$M/yr	0.311	0.932
Annual total cost	\$M	3.72	13.59
\$/tonne CO ₂		1.73	6.30

Subsea CO₂ Pipeline Transport/Ocean Disposal Model – Case Studies

STUDY	REFERENCE
GEODISC	Allinson, G. and V. Nguyen, "The economics of CO ₂ sequestration in Australia," presented at Fifth International Conference on Greenhouse Gas Control Technologies Cairns, Australia, 2000.
UMass	Golomb, D., "Transport systems for ocean disposal of CO ₂ and their environmental effects," <i>Energy Convers. Mgmt</i> , vol. 38, suppl., pp. 279-286, 1997.
IEA ocean	Ormerod, W., "The disposal of carbon dioxide from fossil fuel fired power stations," IEA Greenhouse R&D Programme, Cheltenham. Tech. Rep. IEAGHG/SR3, Jun. 1994.
McDermott	Sarv, H., "Large-scale CO ₂ transportation and deep ocean sequestration," McDermott Technology Inc., Ohio. Tech. Rep. DE-AC26-98FT40412, Mar. 1999.
British Coal	Summerfield, I.R., S.H. Goldthorpe, N. Williams and A. Sheikh, "Costs of CO ₂ disposal options," <i>Energy Convers. Mgmt</i> , vol. 34, no. 9-11, pp. 1105-1112, 1993.

Subsea CO₂ Pipeline Transport/Ocean Disposal Model – Pipeline Characteristics in Case Studies

Study	CO ₂ flow rate (Mt/yr)	Initial CO ₂ pressure (bar)	Diameter (m)	Length (km)	Injection depth (m)	Recompression station included
GEODISC	5.67	205	0.660	200	100.0	No
UMass	8.20	140.0	0.600	200	1,000	No
IEA ocean	19.00	74.0 (liquid CO ₂)	0.800	100.0	500	Ignored
McDermott	200 (total) 33.3 (each pipe)	130.0	0.760 (6 pipes)	500	3,000	Yes
British Coal	3.63	136.0	0.350	517	2,000	Yes

Subsea CO₂ Pipeline Transport/Ocean Disposal Model – Diameter Comparison

Diameter as a Function of CO₂ Mass Flow Rate

Subsea CO₂ Pipeline Transport/Ocean Disposal Model – Capital Cost Comparison

Subsea CO₂ Pipeline Transport/Ocean Disposal Model – O&M Cost Comparison

CO₂ Ocean Storage – Design Input

Parameter	Units	Base Case	300 km Case
CO ₂ flow rate	t/d	22,167	
	Mt/yr	8.09	
Plant capacity factor		0.8	
Temperature	°C	25	
Pipeline length	km	100	300
Injection depth	ft	6,600	
Initial pressure of CO ₂	bar	152	
Gravity head	bar	180	
Diffuser head loss	bar	20	
Min. outlet pressure of CO ₂	bar	200	
Pressure drop per unit length	Pa/m	112	37
Capital charge rate	%/yr	15	

CO₂ Ocean Storage – Design Output

Parameter	Units	Base Case	300 km Case
Pipe diameter	m	0.369	0.456
Pipeline capital cost	\$M	29.5	109.4
Injector cost	\$M	14.5	
Pipeline O&M cost	\$M/yr	0.311	0.932
Annual total cost	\$M	6.91	19.52
\$/tonne CO ₂		3.20	9.05

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model - Definitions

- **Injectivity** is the mass flow rate of CO₂ per unit of reservoir thickness and per unit of downhole pressure difference.
- **Mobility** is the absolute permeability divided by the viscosity.

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Correlation of Injectivity and Mobility

Source: Law and Bachu, 1998

CO₂ Injectivity as a Function of CO₂ Mobility

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Well Drilling Cost Correlation

Source: 1998 Joint Association Survey on Drilling Costs, Nov. 1999

Well Drilling Cost as a Function of Depth
1998 Onshore Gas & Oil Well Data

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Case Studies

STUDY	REFERENCE
GEODISC	Allinson, G. and V. Nguyen, "The economics of CO ₂ sequestration in Australia," presented at Fifth International Conference on Greenhouse Gas Control Technologies, Cairns, Australia, 2000.
Elsamprojekt	Krom, T.H., F.L. Jacobsen and K.H. Ipsen, "Aquifer based carbon dioxide disposal in Denmark," <i>Energy Convers. Mgmt.</i> , vol. 34, no. 9-11, pp. 933-940, 1993.
IEA aquifer	Ormerod, W., "The disposal of carbon dioxide from fossil fuel fired power stations," IEA Greenhouse R&D Programme, Cheltenham. Tech. Rep. IEAGHG/SR3, Jun. 1994.
IEA depleted reservoir	Ormerod, W., "The disposal of carbon dioxide from fossil fuel fired power stations," IEA Greenhouse R&D Programme, Cheltenham. Tech. Rep. IEAGHG/SR3, Jun. 1994.
Sleipner West	Steeffel, C., "Intercomparison of Simulation Models for CO ₂ Disposal in Underground Storage Reservoirs – Test Problem 7: CO ₂ Injection into a 2-D Layered Brine Formation," [Online document], [cited 2001 April 30]. Available HTTP: http://esd.lbl.gov/GEOSEQ/code/testprob_7.html

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Characteristics of Case Studies

Study	CO ₂ flow rate (t/d)	Injection pressure (MPa)	Reservoir pressure (MPa)	Thickness (m)	Depth (m)	Permeability (md)	Well number	Location
GEODISC	15,780	17.41	17.24	400	1,600	300	4	Offshore
Elsamprojekt	3,770	-	-	-	1,100	-	12	Onshore
IEA aquifer	10,685	20.3	11.3	55	1,459	13	6	Onshore
IEA depleted reservoir	8,560	10.4	3.0	-	2,500	100	4	Onshore
Sleipner West	2,740	11.0	9.0	184	1,020	10	1	Offshore

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Injectivity Comparison

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Well Drilling Cost Comparison

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Offshore Well Drilling Cost Comparison

CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection Model – Typical Reservoir Properties

Parameter	Units	Gas Reservoir Typical	Gas Reservoir Range	Oil Reservoir Typical	Oil Reservoir Range
Reservoir pressure	MPa	3.45	2.07 – 6.89	13.78	3.45 – 20.7
Thickness	m	30.5	15.24 – 61.0	42.7	21.3 – 61.0
Depth	m	1524	610 – 3048	1554	1524 – 2134
Permeability	md	1	0.01 – 100	5	5 – 19

Source: Vello Kuuskraa, e-mail communication, March 28, 2001

**CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection
Model – Design Input**

Parameter	Units	Gas Reservoir*	Oil Reservoir*	Aquifer**
CO ₂ mass flow rate	t/d	7,389	7,389	7,389
Downhole injection pressure	MPa	15.2	15.2	15.2
Reservoir pressure	MPa	3.45	13.78	8.62
Thickness	m	30.5	42.7	36.6
Depth	m	1524	1554	1539
Permeability	md	1	5	3
Capital charge rate	%/yr	15	15	15

* From Vello Kuuskraa

** Midpoint between gas and oil reservoir properties

**CO₂ Aquifer/Depleted Hydrocarbon Reservoir Injection
Model – Design Output**

Parameter	Units	Gas Reservoir	Oil Reservoir	Aquifer
CO ₂ mobility	mPa.s	0.018	0.060	0.023
CO ₂ injectivity	t/d/m/MPa	0.771	1.071	1.579
Injection rate per well	t/d	276	64.9	380
Number of wells		27	114	20
Well drilling cost	\$M	8.11	35.1	6.08
O&M cost	\$M/yr	2.0	2.0	2.0
Annual total cost	\$M	3.22	7.26	2.91
\$/tonne CO ₂		1.49	3.37	1.35

4.0 Cropland CO₂ Sequestration via Reduced Tillage

The following section is an overview of concept development, data sources, changes in soil organic carbon, changes in greenhouse gas emissions associated with cropping system inputs, and typical costs for reducing tillage and for accelerating adoption of reduced tillage. Costs (\$/metric tonne carbon equivalent) of enhancing cropland CO₂ sequestration via reducing tillage are being estimated for regionally important cropping systems in the United States. This work has involved a strong informal collaboration with Oak Ridge National Laboratory's Center for Enhancing Carbon Sequestration in Terrestrial Ecosystems and strong formal collaboration with the Conservation Tillage Information Center.

ppi public power institute

Economics of CO₂ Sequestration via Reducing Tillage on U.S Cropland: Status Report

B.R. Bock
Washington, D.C.
5/14/01

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ppi public power institute

Physical Components of GHG Abatement from Reducing Tillage

- Increased CO₂ sequestration in soil organic matter until new equilibrium reached (0-20, 20-40 years)
- Net decrease in GHG emissions from tillage system inputs for as long as practice continues
 - Less machinery
 - Less fuel
 - Less soil erosion and CO₂ emission from eroded soil
 - More pesticides
 - More N fertilizer and N₂O emissions in some cases

2

Cost Components for GHG Abatement via Reducing Tillage

- Adoption incentive to farmer for reducing tillage; compensate farmer for:
 - Long-term profit difference (often small)
 - Added profit risk, especially in early years
 - Purchasing different equipment in some cases
- Transaction cost (bundling and brokering)
- Monitoring cost

Total cost to utility

3

U.S. Tillage-System Means for Corn, Soybeans, and Wheat

- ORNL survey of 76 long-term tillage studies
 - Carbon sequestered in soil organic matter
 - Relative yields
- ORNL assessment of C flux as affected by tillage system production inputs (machinery, fuel, other)
- Impact of tillage system on N₂O emissions, assuming existing and recommended N rates and an IPCC emissions factor
- Corn and soybean production costs based on Purdue ID-191
- Wheat production costs based on CSU and UT budgets
- CTIC estimates of farmer incentives required to accelerate adoption of reduced tillage

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Change in C flux from Atmosphere by Converting from CT to NT

	Corn	Soybeans	Wheat	U.S. mean: all crops
	kg C/ha/yr			
C sequest. in soil	-460	-333	23	-337
C emissions from equip. and fuel	-49	-44	-44	-46
C emissions from other inputs	41	6	-11	12
Net flux	-468	-371	-32	-371

West and Marland, ORNL

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State and Regional GHG Abatement Means: Data Sources

- Iowa Carbon Storage Project--complete
- Indiana Carbon Storage Project--nearly complete
- Regional estimates from West and Marland, ORNL--to be completed in time for our project
- Individual studies
 - Conventional-till corn/soybeans to no-till corn/double cropped wheat&soybeans
 - Conventional to no-till cotton
 - Conventional wheat-fallow to no-till wheat-corn-fallow

- Data gap--C sequestration x tillage system: irrigated

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IPCC Default N₂O Emission Factor for Commercial N Fertilizer Use

- Direct N₂O-N emission = 1.25% of applied N
- Indirect N₂O-N emission from:
 - Volatilized NH₃ and NO_x = 0.1% of applied N
 - Leached N = 0.75% of applied N
- Total N₂O-N emission = 2.1% of applied N
- N₂O = 1.57 x N₂O-N
- CO₂ equivalent = 310 x N₂O
- C equivalent (CE) = 0.272 x CO₂ equivalent
- 1 kg applied N = 2.78 kg CE from N₂O

N Rate Recommendations

- Corn Belt--No adjustments for tillage system
 - Anhydrous ammonia knifed below zone of labile organic matter
 - Reduces N fertilizer tie-up in labile organic matter
 - Reduces denitrification (main source of N_2O)
 - Minimizes ammonia volatilization
- Mid-South and Mid-Atlantic--10 to 15% higher with NT
 - Urea and urea-ammonium nitrate solution broadcast on soil surface
 - Higher ammonia volatilization potential
 - More susceptible to N fertilizer tie-up in labile organic matter
 - More susceptible to denitrification

Average N Rates--U.S., 1995

	CT with plow	CT w/o plow	NT
	kg N/ha		
Corn	108	148	150
Soybean	12	35	29
Wheat	70	37	58

Mean N Rates for Corn: 10 Major Corn States, 1995

	Conv. till with plow	Conv. till w/o plow	Mulch till	No till
N rate, kg/ha	108	148	150	150
% fields w/ N fert.	93	98	97	98
% fields w/ manure	38	15	14	8

NASS survey, 1995

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Change in C flux from Atmosphere by Converting from CT to NT

Tillage system	SOC	N fert.	Lime	Fuel	N ₂ O	Net
kg CE/ha/yr						
CT	0	73	63	46	141	323
NT	-300	73	92	33	152	39
Diff.	-300	0	29	-13	11	-284

Robertson et al., MSU

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Less CO₂ Emission from Eroded Soil: Sample Calculation

- Reduction in soil erosion = 5000 kg/ha/yr
- 3% soil organic carbon (SOC) in eroded soil
- 20% of SOC in eroded soil released as CO₂
- Reduction in CO₂ emissions = $5000 \times 0.03 \times 0.2 = 30 \text{ kgC/ha/yr}$

Cost Components for GHG Abatement via Reducing Tillage

- Adoption incentive to farmer for reducing tillage; compensate farmer for:
 - Long-term profit difference (often small)
 - Added profit risk, especially in early years
 - Changing equipment in some cases
- Transaction cost (bundling and brokering)
- Monitoring cost

Total cost to utility

Added Risk, Especially in Early Years

- Soil quality improvements not yet fully developed and reflected in improved yields
 - Increased soil organic matter
 - Greater macropore development, etc.,
- Farmer still on steep learning curve
 - Reduced stand (lower and less uniform plant emergence)--planting technique, seed treatments, “cold-germ” hybrids
 - Weed problems--minimal weeds going into reduced till, herbicide timeliness, “Roundup ready” crops
 - Slower seedling emergence and early growth, especially in cool, wet springs--strip till, starter fertilizer

Stand Problem

Long-Term No-Till Corn Yields

Years in No-till	Iowa	Indiana	Ohio	Mean	No. fields
bu/acre					
2-5	138	126	164	143	71
>5	163	160	167	163	84

Conservation Tillage Information Center

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Long-term Profit vs. Fall Plow Indiana Corn/Soybean Rotation

Soil	Ridge-till	No-till
return vs fall plow, \$/acre/year		
Brookston	14	7
Crosby	19	17
Eroded Miami	23	35

Purdue Univ. ID 191

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Indiana Tillage Practices--2000

	Conservation tillage			Conv. tillage	
	No	Ridge	Mulch	15-30%	0-15%
	%				
Corn	21	0.2	8	18	53
Soybeans	59	0.2	15	11	15

Conservation Tillage Information Center

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Farmer Incentive Required for Accelerating Adoption of Reduce Tillage on Row Crops

- Experience with 20 years of incentive and educational projects suggests:
- \$10 to 20/acre/year
- \$25 to 50/hectare/year
- 0.5 tonne CE/hectare/year ==>
\$50 to 100/tonne CE

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Eastern Colorado Wheat Fallow Tillage Systems

Tillage system	Tillage operations	Herbicides
Conventional stubble mulch	7 sweep and rod weeder	None
Reduce tillage	3 sweep and rod weeder	post harvest
No tillage	none	post harvest + 3 contact

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NE Colorado

Tillage system	WF	WCF	WCMF
change in return vs. CT-WF, \$/acre/year			
CT	0	16	11
RT	-3	14	8
NT	-11	10	5

Peterson and Westfall. CSU.

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SE Colorado

Tillage system	WF	WCF	WCMF
change in return vs. CT-WF, \$/acre/year			
CT	0	-5	-8
RT	-3	-7	-9
NT	-10	-10	-10

Peterson and Westfall. CSU.

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Soil Carbon Sequestration: Eastern Colorado

NT WF	NT WCMF	Difference
kg C/ha/yr		
-35	125	160

Peterson and Westfall, CSU

5.0 Forestry CO₂ Sequestration Options

It is anticipated that the least-cost forestry CO₂ sequestration options will be in developing countries, at least initially. Therefore, the forestry component of this project is emphasizing case studies in developing countries that have broad applicability. Two U.S. case studies are being developed for purposes of comparison. Work on this concept has involved strong formal collaboration with the Edinburgh Centre for Carbon Management. Case studies being developed are as follows:

- Establishment of small-scale plantations of hardwoods in lowland, high rainfall areas of southern Mexico (will be relevant to southern Mexico, Central America, some areas of Ecuador, Bolivia, Brazil, Sri Lanka and West Africa)
- Restoration of degraded pine-oak upland forests in southern Mexico (will be relevant for many Andean areas, with minor adjustments)
- Establishment of pinus plantations in Uganda (will be applicable to many areas in Africa and Latin America)
- Establishment of tamarind agroforestry system in southern India (relevant to large areas in India)
- Restoration of degraded Miombo woodland in southern Africa
- Establishment of native type Caledonian pine-oak forest in central Scotland
- Establishment of Loblolly pine plantations in the Southern United States
- Establishment of Douglas fir plantations in the U.S. Pacific North West

The section overview concept development and data sources for the forestry case studies listed above:

Forestry Sequestration and Economic Assessment

John Davison
IEA Greenhouse Gas R&D Programme

www.ieagreen.org.uk

Main Issues

- Quantity of carbon stored
 - Afforestation
 - Avoidance of deforestation
 - Timber harvesting
 - Leakage
- Full fuel cycle emissions
 - Non-CO₂ GHGs
- Economics
 - Forestry costs
 - Timing and discounting

Carbon Storage in Forests

Carbon Sequestration

Carbon Storage Data

- Propose including data for different forest types and management options
- Data sources
 - IEA GHG Chiapas Study
 - ◆ Mexican forest data only
 - IEA GHG Full Fuel Cycle Study
 - ◆ UK forest data only
 - CO2FIX computer model
 - Published data

Timber Harvesting

- Provides local benefits
- Reduces risks of forest loss
- Revenue from timber may reduce net costs
- Reduces average C density per ha
- Depresses timber prices / increases demand
- Crowds out commercial plantations (predicted to be small - about 10%)
- Carbon is stored in products (not included in the Kyoto Protocol)
- Include in our study as a sensitivity

Preservation of Existing Forests

- Mature native forests are usually considered to be in carbon balance
- Forest preservation has GHG benefits only if there is a risk of deforestation
- Benefits depend on the baseline rate of loss
 - Observed trends in the country or region
 - Standard management practice
 - More detailed methodologies for specific projects
- Generally a cost effective way of avoiding GHG emissions
- Leakage is a major issue

Avoidance of deforestation

Leakage

- Indirect impact at another place or time
 - If a forest is preserved, would another forest be felled to satisfy demands for wood or land?
 - Would timber harvesting in sequestration forests crowd out commercial forests?
- Leakage in other sequestration techniques
 - e.g. oil from CO₂-enhanced EOR
- Propose using a 'leakage factor' in the spreadsheet

Non-CO₂ GHGs

- Forests emit large quantities of N₂O
 - Estimated to be about 1.1 Gt C-equivalent/year
 - Equivalent 20% of fossil fuel CO₂ emissions
- Forests are sources and sinks of methane
- Scientific uncertainties are high
- Other land uses also emit non-CO₂ GHGs
- No generic methods to assess impacts of forestry sequestration on non-CO₂ GHGs
- Non-CO₂ GHGs from forestry are not included in the Kyoto Protocol
- Include in our study as a sensitivity

Comparison of Non-CO₂ GHGs

- Global Warming Potential depends on time horizon
 - CH₄: 56 (20yr horizon), 21 (100yr), 6.5 (500 yr)
- Suggest we use a 100 year horizon
- GWPs are calculated without discounting
- Not consistent with the rest of our study but it is accepted practice

Forestry Costs

- Planting and maintenance costs
- Land costs
 - Annual marginal cost of land
 - Market values are distorted by subsidies
 - Costs should be consistent with the soils assessment
- Cost data sources
 - IEA GHG Full Fuel Cycle and Chiapas studies
 - Published data

6.0 Life Cycle Analysis Approach

This section overviews our approach concerning life cycle analysis. The life cycle analysis will assess the cost per metric tonne carbon equivalent of avoided greenhouse gas emissions associated with the various CO₂ sequestration options but will not evaluate costs associated with impacts of greenhouse gases on global climate change (e.g., costs associated with impacts on natural resources). Arrangements have been made to retain the services of a consultant formerly with the IEA Greenhouse Gas Programme to provide guidance on performing the life cycle analysis for each concept.

Life Cycle Analysis (LCA)

“Simply stated, the life cycle of a **product** embraces all of the activities that go into making, transporting, using and disposing of that product.

The typical life cycle consists of a series of stages running from extraction of raw materials, through design and **formulation**, processing, manufacturing, **packaging**, distribution, use, **re-use**, **recycling** and, ultimately, waste disposal.”

EPRI

Life Cycle Analysis (LCA)

- Started in the 1970s
- My product is greener than yours
- Sustainability in developing countries
- 1990s: International Standards Organization
 - ISO 14040 Life Cycle Assessment - Principles and Guidelines
 - ISO 14041 Life Cycle Assessment - Life Cycle Inventory Analysis
 - ISO 14042 Life Cycle Assessment - Impact Assessment
 - ISO 14043 Life Cycle Assessment - Interpretation
 - ISO 14048 Life Cycle Assessment - Data Documentation Format
 - ISO 14049 Life Cycle Assessment - Examples for the application of ISO 14041

EPRI

Level of Sophistication

- Detailed
- **Conceptual**-used to make an assessment of environmental aspects based on a limited and usually qualitative inventory
- **Simplified**-covering the whole life cycle but superficial e.g. using generic data (qualitative and/or quantitative), standard modules for transportation or energy production, followed by a simplified assessment i.e. focusing on the most important environmental aspects and/or potential environmental impacts and/or stages of the life cycle and/or phases of the LCA and a thorough assessment of the reliability of the results.
- Streamlined LCA, Partial LCA, screening LCA, Life cycle review, simplified LCA, Life cycle thinking, LCA concept, LCA tool, etc.

EPRI

Life Cycle Analysis (LCA)

- A typical LCA-study consists of the following stages:
 - Goal and **scope** definition.
 - A detailed **life cycle inventory** (LCI) analysis, with compilation of data both about energy and resource use and on emissions to the environment, throughout the life cycle.
 - An assessment of the **potential impacts** associated with the identified forms of resource use and environmental emissions.
 - The **interpretation** of the results from the previous phases of the study in relation to the objectives of the study.

EPRI

Goal and scope definition

- CO₂ equivalent greenhouse gases avoided costs on a life cycle basis
- 405 MW IGCC net output power plant
- Boundary: Fuel extraction, power generation, transfer to grid (plant boundary), transport, storage or sink enhancement
- \$/Tonne

EPRI

Detailed life cycle inventory (LCI) analysis

- Where do we get this information?
 - Prior LCA power plant analyses
 - IEA GHG Full Fuel Cycle studies
 - Australia work (Rio Tinto)
 - Other studies?
- Who gets the information?
 - IEA GHG
 - Parsons
 - Consultant

EPRI

Other Aspects

- An assessment of the potential impacts associated with the identified forms of resource use and environmental emissions. **We will not do this.**
- The interpretation of the results from the previous phases of the study in relation to the objectives of the study.

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7.0 Comparing Diverse Concepts

A key requirement of this project is to compare concepts that differ greatly in timing and permanence of CO₂ sequestration. The team has tentatively selected the approach described below.

Net Present Value of Abatement

$$\text{NPV} = \int_0^T (p(t)A(t) - C(t))e^{-rt} dt$$

Where:

NPV = net present value

p(t) = carbon price (\$/tonne)

A(t) = abatement (avoided emissions, tonnes/yr)

C(t) = abatement cost (\$/yr)

r = discount rate

t = time (years)

T = planning horizon (e.g., 100 years or infinity)

Calculating Avoided Cost

$$p = \int_0^T C(t)e^{-rt} dt / \int_0^T A(t)e^{-rt} dt$$

Assumes breakdown condition (NPV = 0)

Assumes $p(t)$ is constant over time

Discretize

$$p = \frac{\sum_0^T C(t) (1+r)^{-t}}{\sum_0^T A(t) (1+r)^{-t}}$$

Reduced Tillage Example

- Sequester 1 unit/yr for 20 years at a cost of 1 unit/yr
- Discount rate = 4%
- Timeframe = 100 years
- Case 1 – Release all in years 21-23
- Case 2 – Pay to assure no release
- Case 3 – Farmers change practices so no release

Reduced Tillage Example

	Case 1	Case 2	Case 3
C(t)	1, t=1,20	1, t=1,100	1, t=1,20
A(t)	1, t=1,20 -6.67, t=21,23	1, t=1,20	1, t=1,20
p	2.64	1.80	1.0

Leaky Reservoir Example

Cost of capture and sequestration is
 \$31.93 million/yr for 20 years
 2.16 million tonnes CO₂/yr captured
 1.82 million tonnes CO₂/yr avoided
 Case 1 – No leaks, r=4%, T is infinity
 Case 2 – 0.5%/yr leaks starting in year 51,
 r=4%, T is infinity
 Case 3 – Case 2 leaks, r=0%, T=100 years

Leaky Reservoir Example

	Case 1	Case 2	Case 3
C(t)	31.93, t=1,20	31.93, t=1,20	31.93, t=1,20
A(t)	1.82, t=1,20	1.82, t=1,20 .216, t=51,250	1.82, t=1,20 .216, t=51,100
p	17.55	18.15	25.51

C(t) in millions of dollars, A(t) in millions of tonnes CO₂

8.0 Conclusion

It is too early in this project to draw conclusions concerning the relative economics of the CO₂ sequestration concepts being compared. However, we are confident that we have developed sufficient framework, data bases, and case studies to enable valid comparison of the economics of the diverse set of CO₂ sequestration concepts included in this project and to assess sensitivities to important variables.