DEVELOPMENT OF A CARBON MANAGEMENT GEOGRAPHIC INFORMATION SYSTEM (GIS) FOR THE UNITED STATES

Final Report

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Abstract

In this project a Carbon Management Geographical Information System (GIS) for the US was developed. The GIS stored, integrated, and manipulated information relating to the components of carbon management systems. Additionally, the GIS was used to interpret and analyze the effect of developing these systems.

This report documents the key deliverables from the project:

1. Carbon Management Geographical Information System (GIS) Documentation
2. Stationary CO_2 Source Database
3. Regulatory Data for CCS in United States
4. CO_2 Capture Cost Estimation
5. CO_2 Storage Capacity Tools
6. CO_2 Injection Cost Modeling
7. CO_2 Pipeline Transport Cost Estimation
8. CO_2 Source-Sink Matching Algorithm
9. CO_2 Pipeline Transport and Cost Model

Executive Summary

This is the final report for the project entitled Development of a Carbon Management Geographical Information System (GIS) for the United States. This project was executed by the Massachusetts Institute of Technology (MIT) for the United States Department of Energy (DOE) under award number DE-FC26-02NT41622.

Key tasks performed under this project included:

- Development of a range of modeling tools for the capture, transportation and sequestration of CO_2; development of a user interface and analysis tools.
- Maintainance the Carbon Management GIS server which provided access to all authorized users.
- Incorporation of new data as it becomes available.
- Collaboration with the Regional Sequestration Partnerships and NATCARB. This included participation in the GIS Working Group.

This report documents the key deliverables from the project:

1. Carbon Management Geographical Information System (GIS) Documentation
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7. CO_2 Pipeline Transport Cost Estimation
8. CO_2 Source-Sink Matching Algorithm

9. CO_2 Pipeline Transport and Cost Model

This documentation and related computer codes are posted with open access on the web and can be downloading from:http://sequestration.mit.edu/energylab/wikka.php?wakka=DocumentLink

Experimental

This project involves computer modeling and there is no laboratory work associated with this project.

Results and Discussion

We developed a Carbon Management Geographical Information System (GIS) for the United States. In this section, we review the major deliverables in this effort. Additional details for each component can be found in the nine annexes of the report.

Carbon Management System and Data

The research into the design and use of the Carbon Management GIS are summarized in the following theses:

- Cheng, D.S., "Integration of Distributed and Heterogeneous Information for Public-Private Policy Analyses," M.I.T. Masters Thesis, June (2004). http://sequestration.mit.edu/pdf/David_Cheng_thesis_June2004.pdf

- Singh, N., "A Systems Perspective for Assessing Carbon Dioxide Capture and Storage Opportunities," M.I.T. Masters Thesis, June (2004). http://sequestration.mit.edu/pdf/Nisheeth_Singh_thesis_June2004.pdf

The Carbon Management GIS was then constructed to consist of a Database Server, an Internet Mapping Server, a Documents Server, multiple workstations, and data layers. The Database Server stores all of the base data for the GIS database and provides the data to the other parts of the GIS system. The Internet Mapping Server provides outside users access to the GIS database, GIS carbon management data and maps. The carbon dioxide capture and storage (CCS) data layers include national political, geographical, and regulatory information, nationwide stationary CO_2 sources, and potential geographical CO_2 sinks (coal beds, oil/gas reservoirs, brine aquifers). Detailed documentation for the Carbon Management GIS is found in Annex 1.

A major update of the CO_2 source layer occurred in June 2009. The database contains the following nine major stationary source categories: Power plants, Ammonia Plants, Cement plants, Ethanol, Ethylene plants, Ethylene oxide plants, Gas processing facilities, Iron & steel plants and Refineries. The USEPA eGRID database was used exclusively for the power plant data in this database. A variety of sources were used for the other categories. Detailed documentation for the CO_2 sources is found in Annex 2.

The research into the design of the regulatory and political layers is summarized in the following thesis:

- Smith, A.M., "Regulatory Issues Controlling Carbon Capture and Storage," M.I.T. Masters Thesis, June (2004). http://sequestration.mit.edu/pdf/Adam_Smith_thesis_June2004.pdf

These layers include information on the Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Program and state-level action on climate change. To assist in the siting of future CCS projects, we included land use characterizations, including several types of protected and restricted land use areas. Detailed documentation for the regulatory and political layers is found in Annex 3.

CCS Costs

One important function of the Carbon Management GIS is to do costing. This involved developing algorithms to cost the key CCS components of capture, transport, and storage.

We incorporated the "*Generic CO_2 Capture Retrofit*" spreadsheet prepared by *SFA Pacific, Inc*. as the basis for calculating the CO_2 capture cost for stationary CO_2 sources. These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour); (2) the flue gas composition (volume share or weight share of CO_2 in flue gas); and (3) the annual load factor. Detailed documentation for the capture cost methodology is found in Annex 4.

The cost estimation modeling tool for the geologic CO_2 storage has two major components: the CO_2 injectivity model and storage cost model. We adopted two different methods in developing the CO_2 injectivity model: Law & Bachu method and ARI method. The injectivity model is used to calculate the injection rate per well and thus the number of wells required for storage in saline aquifers only. The storage cost model creates a set of capital and O&M cost factors that are used to determine total storage cost based on well number. Detailed documentation for the storage cost methodology is found in Annex 6.

The CO_2 pipeline and transportation model is calculates the lease cost CO_2 transport pathway. The first step is the calculation of the pipeline diameter as a function of the design capacity for the CO_2 flow rate. Next, we establish obstacle layers (e.g., river crossings, mountains, populated areas) to be considered by the CO_2 transport cost model and assign relative weights to each obstacle to simulate their affect on pipeline costs. Then we identified the least-cost pipeline route between sources and sinks based on the obstacle layers. Finally, an economic module is used to calculate the CO_2 transport pipeline construction cost and O&M cost. Detailed documentation for the transport cost methodology is found in Annex 7.

Source-Sink Matching

The first step in source sink matching is to establish the storage capacities. We developed standardized capacity tools to estimate the CO_2 storage capacity for each of the following three types of geological CO_2 storage sinks: hydrocarbon (oil & gas) reservoirs, saline formations, and coalbeds. We built ArcGIS models for each capacity tool and integrated them into the ArcGIS system. Detailed documentation for the storage cost methodology is found in Annex 5.

With the identification of the CO_2 sources and available CO_2 sink capacities, we were able to undertake point source to sink matching. This was achieved by an iterative model we developed to (approximately) "optimize" the source-sink matching using the ArcGIS *"spatial analysis tool"*. Detailed documentation for the point source to sink methodology is found in Annex 8.

With the success of the point source to sink matching we then developed a many sources to many sinks modeling tool. This source-sink allocation is a fully integrated, optimal carbon capture and sequestration network that minimizes the full mitigation cost for the network system subject to constraints of the sinks' storage capacity. We developed this tool using a two-step approach:

1. To identify the candidate least-cost pipeline network between all sources and sinks. Each source in the system can connect to any of the sinks.
2. Optimize the source-sink allocation through the pipeline network for the give set of CO_2 sources and sinks that minimizes the full mitigation cost.

We tested this program on the State of California and were successful in presenting a full source-sink matching program for this state. Detailed documentation for the many sources to many sinks methodology is found in Annex 9.

Conclusions

A Carbon Management Geographical Information System (GIS) for the US has been developed. The GIS stores, integrates, and manipulates information relating to CCS. This project set up the system architecture, developed and incorporated data layers, and developed and integrated analysis tools. The following key functions have been incorporated: costing of capture, transport, and storage; capacity estimation; and source-sink matching.

Documentation and related computer codes are posted with open access on the web and can be downloading from:http://sequestration.mit.edu/energylab/wikka.php?wakka=DocumentLink

1 Annex 1: System Documentation

1.1 Introduction

This annex provides the updated version of computer system documentation at MIT Carbon Capture and Sequestration Program by Jan 2007.

In this annex:

- Annex 1.2 lists the system updates by Jan 2007 and summarizes the system configuration of the Carbon Management GIS system (thereafter, GIS system). The GIS system consists of Database Server, Internet Mapping Server, Documents Server and multiple workstations.
- Annex 1.3 provides the basic documentation for the Database Server, which is updated from Oracle 9i to Oracle 10i, and the ArcSDE interface is updated from ArcSDE 4.2 to ArcSDE 9.1.
- Annex 1.4 documents the ArcIMS-based Internet Server, which is connected to NATCARB to provide access to our data and can also be used as a web server for external users without ArcGIS software to access our data. ArcIMS has been updated from 3.0 to 9.1 in current system.
- Annex 1.5 describes the configuration of Apache document server. Currently, two website are served under the apache web server in machine: e40-hjh-server1: sequestion.mit.edu and e40-hjh-server1.mit.edu.
- Annex 1.6 summarizes the basic layers for carbon capture and sequestration that are currently loaded in the GIS. These basic layers include national political, geographical, and regulatory layers, nationwide stationary CO2 sources, and potential geographical CO2 sinks (coal beds, oil/gas reservoirs, brine aquifers) that we have connected at both the national and regional levels.

For the standard GIS users who are interested in using the data available from our GIS system, they can access to most of the data in our server by user account “CMGIS_GUEST” (with password “CMGIS_GUEST”).

For people interested in the system setup and administration of the GIS system, appendices of this annex provide in-depth information on the system configuration, installation, and maintenance procedures:

- Appendix 1-A provides information on the network properties and general installation procedures for both servers and the main workstation.
- Appendix 1-B documents specific installation procedures for the key software installed in each server.
- Appendix 1-C documents the basic scripts needed for server administration and maintenance.
- Appendix 1-D documents the frequently used scripts needed for the database administration.

For system security reasons, system accounts and passwords are not included in this annex.

1.2 System Configuration

The GIS system currently consists of two server computers and multiple workstations. The core data and software services reside on the servers, where they can be consolidated for ease of access as well as provided with the needed computer resources. Analyses and research are done from the desktop workstations by connecting to the servers to access the necessary data. The servers include a Database Server and an Internet Server.

The Database Server (E40-HJH-Server2.mit.edu) stores all of the base data for the GIS database and provides the data to the other parts of the GIS system. It runs on the Linux operating system, with an Oracle 9i database, and the ESRI's ArcSDE interface that allows ESRI GIS products to access the data.

The Internet Server (E40-HJH-Server1.mit.edu) provides outside users access to the GIS database. It runs on the Linux operating system, and requires a web server (currently Apache), and ArcIMS for the external users to access. Currently, the Internet Server is connected to NATCARB Server. Currently, the Internet Server (E40-HJH-Server1.mit.edu) hosts two web sites: sequestration.mit.edu, which is the gateway website for partnerships and outside people to visit our program; e40-hjh-server1.mit.edu, which provides web 2.0 service based on MySQL database and enable documents sharing and backup, mainly for internal research usages.

A Test Server (E40-HJH-SERVER3.mit.edu) was set up to test the effects and combinations of newest versions of systems and application software. It also works as a backup server for our Internet Mapping Service and Database Service.

Individual workstations connect to the servers in order to insert data, run analyses, and perform other GIS operations. The only requirement for a workstation is that it has the ArcGIS software.

Appendix 1-A provides information on the network properties and general installation procedures for both servers and the main workstation. Appendix 1-B provides documentation for the specific installation procedures for the key software for each server. Appendix 1-C and 1-D documents the basic script needed for server administration and database administration, respectively.

1.3 Database Server

1.3.1 Setup

The Database Server (E40-HJH-Server2.mit.edu) runs on the Linux operating system. Both Oracle 9i Enterprise database and ESRI ArcSDE interface are installed in the Database Server (see Appendix 1-B for details). Oracle 9i database is used to store both spatial and nonspatial data in the server. The installation of ArcSDE interface allows ESRI GIS products to access the data.

1.3.2 Software Requirement

Acessing the data stored in the Database Server requires either Oracle 9i Client Software or ESRI ArcGIS software be installed in a user's workstation or personal computer. Although data can be accessed via Oracle, the spatial feature can only be viewed and manipulated via ArcGIS software. Therefore, it is highly recommended that users have ArcGIS version 8.3 or above installed in the user end. Users can get support on the setup and use of ArcGIS from ESRI Support Center (http://support.esri.com).

1.3.3 Accessing Data from the GIS System

With proper software installed in the user end, the data stored in the Database Server can be accessed with an administrator-granted user account in two ways: through either Oracle 9i SQL or ESRI's ArcGIS. In the following, we present instructions on how to access data from the GIS Database Server in both ways. Finally, a public user account with password is provided for users interested in accessing the data.

1.3.4 Access Data via Oracle 9i SQL

(1) Download Oracle 9i Client for Windows;
(2) Install Oracle SQL at the default folder of the local computer;
(3) Open files "C:\Program Files\oracle\ora92\network\Admin\tnsnames.ora" in the Notepad. At the bottom of the file, add the following script and save:

```
ccstp =
 (DESCRIPTION =
  (ADDRESS_LIST =
   (ADDRESS = (PROTOCOL = TCP)(HOST = e40-hjh-server2.mit.edu)(PORT = 1521))
  )
  (CONNECT_DATA = (SID = ccstp))
 )
```

(4) When logging in SQL plus, enter the following information:

User name:	your username
Password:	your password
Host string:	ccstp

1.3.5 Access Data via ArcGIS

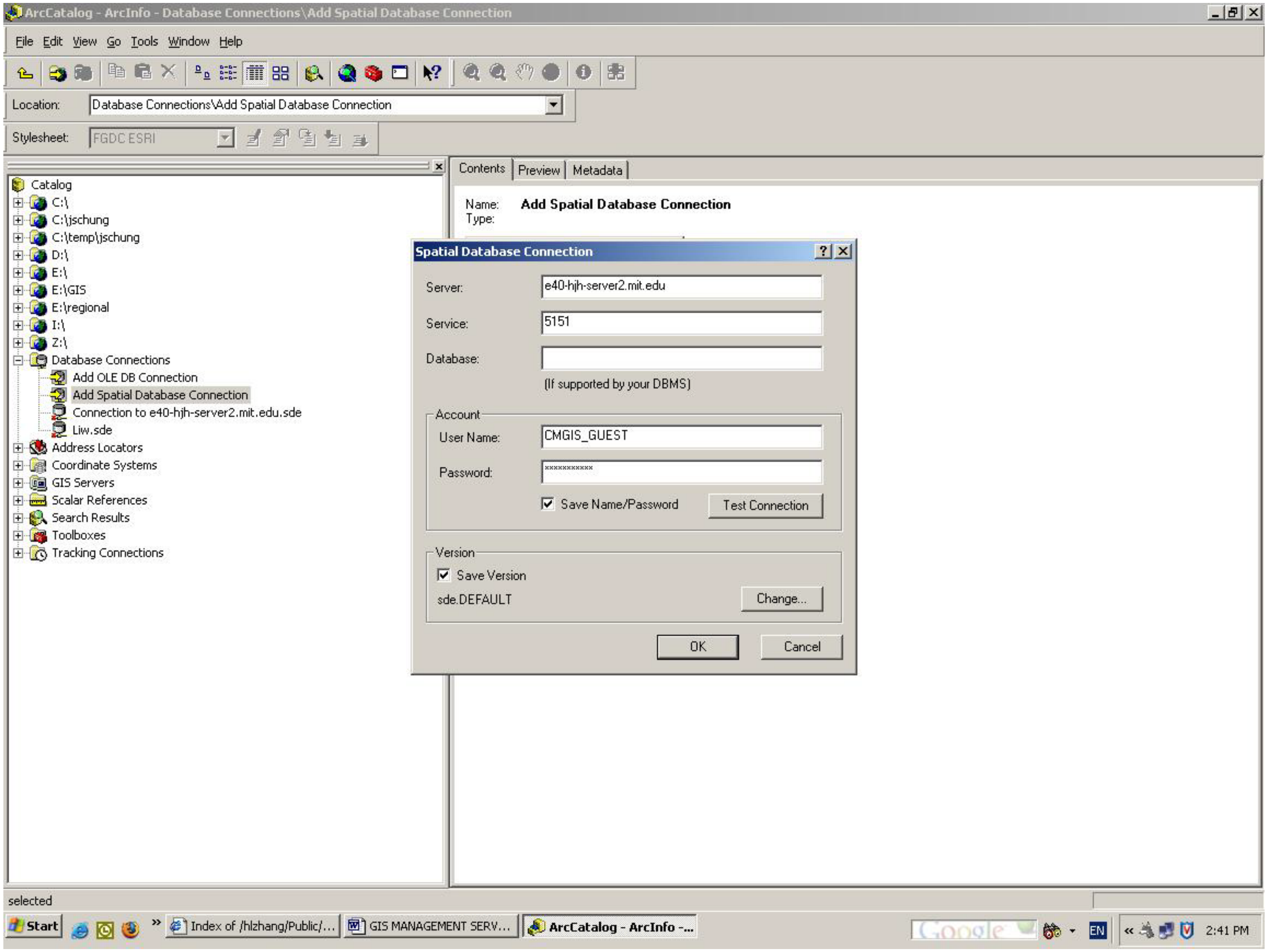
(1) Install ***ArcGIS*** for Windows version 8.3 or above in the local computer;
(2) Launch ***ArcGIS→ArcCatalog***;
(3) On the left window, find ***Database Connections***, double click ***Add Spatial Database Connections*****.** Depending on the version of the software installed, the screen should be similar as the one in Figure 1-1;
(4) Enter the following account information and connect:

IP:	e40-hjh-server2.mit.edu
Service:	port: 5151
Database:	(leave black)
User Name:	your username
Password:	your password

1.3.6 User Account and Password

A standard public user account "CMGIS_GUEST" with the same password "CMGIS_GUEST" is created for all guest visitors to the Database. Users logging in with the "CMGIS_GUEST" account can read and download all the basic tables and spatial layers that are granted to "public" access (summarized in Annex 1-5), but has no privilege to edit or save data in the server. Users interested in getting privilege to write to the server should contact the GIS system administrator to request individual accounts and passwords.

Figure 1-1 Access Data via ArcCatalog

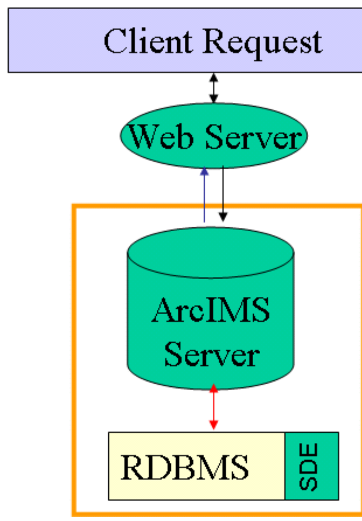


1.4 Internet Mapping Server

1.4.1 Setup

The Internet Server (E40-HJH-Server1.mit.edu) runs on the Linux operating system and requires a web server (currently Apache 2.0.52). The ESRI's ArcIMS 9.1 Internet map server is also installed to support Internet access to the carbon management GIS data and maps from outside the Carbon Sequestration group (see Appendix 1-B for details). Client computers can access the ArcIMS server using a web browser or a supported software program. When a client makes a request for the ArcIMS service, the request is first handled by the web server, and then passed through to ArcIMS. A response is sent back through the web server to the client (see Figure 1-2).

Figure 1-2 Internet Server Architecture



1.4.2 Server Configuration

The ArcIMS server plays a double role in distributing the data in the GIS database: First, it serves as the Internet server for the Carbon Management GIS system to publish the nationwide spatial data in its database; Secondly, it serves as the local ArcIMS server for the Southeast Regional Carbon Sequestration Partnership (SECARB) to connect to the National Carbon Sequestration Atlas (NATCARB) to publish the regional spatial data in the SECARB database. Therefore, the ArcIMS server is configured match both requirements. The following are the steps we have taken to prepare image servers in ArcIMS to publish our data:

(1) Select which data in the database are to be published;
(2) Use ArcIMS Author to develop a map file that includes the selected data layers from our GIS server, save it as an AXL file.
(3) Use ArcIMS Administrator to create and start an ArcIMS image server that uses the authored AXL file to prepare map to the published;
(4) Use ArcIMS Designer to create the website displaying the map.

1.4.3 Client Access

With proper software installed in the client end, users can access the Internet map server using a web browser or a supported software program. The Internet map server can be accessed via any type of web server as long as a Java virtual machine (http://java.sun.com/j2se/1.4.2/download.html) is installed. However, even with the specific Java version installed, the functions the user can use by accessing the Internet map server are limited. Therefore, we recommend that users use ArcExplorer version 2.0 or above to access the Internet map server. In the following, we will provide instructions on how to access the Internet map server in both ways.

1.4.4 Access Internet Server via Web Browser

An integrated mapping system is set up for browsing the SECARB spatial dataset: http://e40-hjh-server1.mit.edu/website/SouthEast. This client is based on HTML services, Java Virtual machine is not required, but in further versions of this mapping system, when Java virtual machine is needed, the package including the specific Java version will be downloaded and installed automatically.

Through the map viewer, users can choose layers of their interest and corresponding legend to display in their specified order. They can also identify and query the detailed data in a particular layer as well.

1.4.5 Access Internet Server via ArcExplorer

Client computers can also access the ArcIMS internet server through the free software ArcExploer offered by ESRI:

(1) Install ***ArcExploer*** 2 or above in local computer. The ArcExplorer software package is freely available on ESRI website at http://www.esri.com/software/arcexplorer/;
(2) Launch ***ArcExplore->WWW***;
(3) Click ***Open ArcExplore Web Site***, enter http://e40-hjh-server1.mit.edu/website/SouthEast

1.5 Internet Document Server

1.5.1 Setup

The internet document services are accomplished with a web server (Apache 2.0.52) on an update Linux operating system: Advanced Server 4.0. Currently, two web sites are being hosted on the computer e40-hjh-server1: sequestration.mit.edu and e40-hjh-server1.mit.edu. Sequestion.mit.edu is the gateway web site for Carbon Capture and Sequestration Technologies Program at MIT and provides such services as html publication, data download with restricted access to partnerships, host of web-based tools such as: CO_2 Thermophysical Property Calculation. E40-hjh-server1.mit.edu is a wikki site based on MySQL database, and provides web 2.0 services such as: document sharing, upload, download, comments, and contents search, etc.

1.5.2 Server Configuration

After Apache 2.0.52 is set up, its configure file was edited to allow setting up two ip-based virtual hosts: sequestration.mit.edu and e40-hjh-server1.mit.edu. For Apache to host multiple IPs, the underlying machine must accept requests for multiple IPs. For this purpose, IP aliasing must be activated in the kernel.

Once the kernel has been configured for IP aliasing, the commands ifconfig and route can be used to set up additional IPs on the host. These commands must be executed as root. Further IPs can be added with commands like the following:

```
/sbin/ifconfig eth0:0 18.172.4.86
```

Once IP aliasing has been set up on the system, specify a separate VirtualHost block for the virtual server: sequestion.mit.edu as follows:

```
<VirtualHost 18.172.4.86:80>
   #ServerAdmin webmaster@dummy-host.example.com
   DocumentRoot /var/www/html3/
   ServerName sequestration.mit.edu
   ErrorLog /var/log/sequestration_error.log
   CustomLog /var/log/sequestration.log common
</VirtualHost>
```

1.6 Data Description

This section presents a summary description of the data stored in the Carbon Management GIS Database. All the spatial data are in GCS_North_American_1983 geographical coordinate system. And most of them are granted public access under a common public account "CMGIS_GUEST"[1]. The data can be grouped into five major categories: political layers, geography layers, regulatory data, stationary CO_2 source data, and potential CO_2 sink data. Table 1-1 provides a list of data files that are currently available from the database with their locations, formats and sources. In the following, we will summarize the data for each category.

1.6.1 Political Layers

The political data include polygon boundary layers for state, county, metropolitan statistical area (MSA), and urban areas for United States. Point layers for locations of census-defined places, cities, and major cities with population more than 10,000 (in year 2000) are also included.

[1] The only exception is the aquifer data from University of Texas, Bureau of Economic Geology (UTBEG). The entire UTBEG aquifer data are loaded in the server for internal use only. But one shape file that shows the coverage of the UTBEG data is granted to public use. Users can find information on how to download the UTBEG aquifer database from their website: http://www.beg.utexas.edu/environqlty/co2seq/.

1.6.2 Geography Layers

The GIS database also provides spatial layers that are needed for carbon transportation analysis. Such spatial layers include hydro units, water bodies, railroads, and road networks. Separate layers for major lakes, major rivers and interstate highways are also provided to highlight the basic geographical features.

1.6.3 Regulatory Data[2]

The regulatory data in the database are based on the data Adam Smith (2004), who is a former research assistant in the MIT CCSTP group, collected and compiled in his thesis "*Regulatory Issues Controlling Carbon Capture and Storage*". The carbon capture and storage projects in the future need to consider a combination of land ownership and regulation policies. Land use policies that constrain or forbid development projects are likely to impose restrictions on carbon transport and storage in those "protected" areas.

[2] This section provides a brief summary of the regulatory data in the GIS database. A more detailed description of the regulatory layers is available from the March 2005 progress report "*Documentation for Regulatory Data for Carbon Capture and Storage in the United States*".

Table 1-1 Data Summary of the Carbon Management GIS Database

Feature Dataset	SDE Feature Class/SDE Table	Format	Data Source
ESRI.POLITICAL	ESRI.STATE_BOUNDARY	Polygon	ESRI Data & Maps
	ESRI.COUNTY_BOUNDARY	Polygon	ESRI Data & Maps
	ESRI.MSA	Polygon	ESRI Data & Maps
	ESRI.URBAN_DTL	Polygon	ESRI Data & Maps
	ESRI.CITIES	Point	ESRI Data & Maps
	ESRI.CITIES_DTL	Point	ESRI Data & Maps
	ESRI.PLACES	Point	ESRI Data & Maps
ESRI.GEOGRAPHY	ESRI.RAILROADS	Polyline	ESRI Data & Maps
	ESRI.ROADS	Polyline	ESRI Data & Maps
	ESRI.INTERSTATEHWYS	Polyline	ESRI Data & Maps
	ESRI.HYDRO_LN	Polyline	ESRI Data & Maps
	ESRI.HYDRO_POLYGON	Polygon	ESRI Data & Maps
	ESRI.WATERBODIES	Polygon	ESRI Data & Maps
	ESRI.MJRIVERS	Polyline	ESRI Data & Maps
	ESRI.MJLAKES	Polygon	ESRI Data & Maps
REGULATORY.PHYSICAL	REGULATORY.PARKS_ESRI	Polygon	ESRI Data & Maps
	REGULATORY.WILDERNESS	Polygon	WILDERNESS
	REGULATORY.FEDLAND_USGS	Polygon	USGS
	REGULATORY.ROADLESS_USDA	Polygon	USDA
	REGULATORY.STATES_CLASS	Polygon	Smith, Adam (2004)
CO2SOURCES.SOURCES	CO2SOURCE.AMMONIA_IFDC_2004	Point	International Fertilizer Development Center
	CO2SOURCE.CEMENT_PCA_2002	Point	Portland Cement Association
	CO2SOURCE.ETHYLENE_OGJ_2001	Point	Oil & Gas Journal
	CO2SOURCE.ETHYLENEOXIDE_CHEMWEEK_2001	Point	Chem Week
	CO2SOURCE.FOSSIL_POWER_EGRID_2000	Point	eGrid
	CO2SOURCE.GASPROCESSING_OGJ_2003	Point	Oil & Gas Journal
	CO2SOURCE.IRONSTEEL_STEELEYE_2001	Point	Steeleye Survey
	CO2SOURCE.REFINERIES_EIA_2004	Point	DOE: Energy Information Administration
CO2SINK.COAL	CO2SINK.COAL_USGS	Polygon	USGS
CO2SINK.AQUIFER	CO2SINK.AQUIFER_BEG	Polygon	UTBEG
CO2SINK.BRINEWELLS	CO2SINK.BRINEWELLS	Point	NETL
	CO2SINK_GASIS	Table	GASIS

Therefore, the first set of regulatory data we incorporate into the GIS system includes layers for the following protected areas:

- National, state, and local park system (Figure 1-3);
- Inventoried roadless area (Figure 1-4);
- Wilderness area (Figure 1-5);
- Federal-owned lands (Figure 1-6).

Another important factor that affects the future of carbon capture and storage is the state regulations on underground injection control (UIC) and state attitudes toward climate change. Smith (2004) studied state UIC program and provided information on each state's UIC program (see Figure 1-7) and statistics on the number of Class I Hazardous Waster Wells and Class II Oil & Gas Wells for each state. He further studied the how proactive states are in addressing climate change and classified them into five categories (see Figure 1-8). We code the information Smith (2004) collected in spatial format and provide it by a SDE feature class in our GIS database. Table 1-2 provides detailed information for this SDE feature class.

Table 1-2 Table Detailed Information in the REGULATORY.STATE_CLASS Layer

Key Fields	Description	Coding
UIC_REG	States Classified by Their Underground Injection Control Programs	Individual State Program Joint State/EPA Program EPA Program
HW_WELL_CLS1	States Categories by Number of UIC Class I Hazardous Waste Wells	No HW Wells 1-10 HW Wells 11-20 HW Wells >70 HW Wells
OG_WELL_CLS2	States Categories by Number of UIC Class II Oil & Gas Wells	No Known Wells 1-100 Wells 101-5,000 Wells 5,001-25,000 Wells >25,000 Wells
ACTION_CLM	State Categories on Climate Change Action	Class I: Most Proactive Class II Class III Class IV:Least Proactive

1.6.4 CO_2 Source Data

Stationary CO_2 source data in the database are grouped into two categories: fossil fuel power plants and non-power stationary CO_2 sources. Fossil fuel power plants in the database are presented in Figure 1-9 by fuel type and annual CO_2 emission. Figure 1-10 presents the seven major non-power stationary CO_2 sources in the region: ammonia, cement, ethylene, ethylene oxide, gas processing, iron & steel, and refineries.

1.6.5 Potential CO_2 Sink Data

The nationwide potential CO_2 sink data we have collected so far include aquifers, brine wells, coalbeds, and gas reservoirs. Figure 1-11 presents the coverage of aquifer and brine wells data in the GIS database. The aquifer data are from University of Texas-Bureau of Economic Geology (UTBEG), while the brine well data are from the U.S. Brine Wells Database compiled by National Energy Technology Laboratory (NETL). The coal data are from U.S. Geological Survey (USGS) and are displayed in Figure 1-12. The Gas Information System (GASIS) from Energy and Environment Analysis, Inc. provides a database of gas reservoir properties for 21 states and the Gulf of Mexico. However, one issue encountered with the GASIS database is that coordinates are only available for a limited number of gas fields (2,633 out of 19,219), all in Appalachian Region. However, the database includes county and state codes for all of the gas fields. Figure 1-13 shows the onshore coverage of the GASIS data by displaying counties by the number of gas fields in each county.

Some additional sink data are collected for the Southeast region during our collaboration with the Southeast Regional Carbon Sequestration Partnership (SECARB). Table 1-3 provides a list of the additional Southeast region data, which includes brine wells, coal wells and oil & gas reservoirs.

Table 1-3 Additional Sink Data for the Southeast Region

Feature Dataset	SDE Feature Class/SDE Table	Format	Data Source
SECARB.BRINEWELL	SECARB.BRINE_WELL_ALOGB	Point	Alabama Oil & Gas Board
SECARB.COAL	SECARB.AL_COAL_AGS_POINT	Point	Alabama Geological Survey
	SECARB.AL_COAL_AGS_POLYGON	Polygon	Alabama Geological Survey
SECARB.OILGAS	SECARB.ALMSFL_OILGAS_AGS	Point	Alabama Geological Survey
	SECARB.TX_GAS_BEG	Polygon	UTBEG
	SECARB.TX_OIL_BEG	Polygon	UTBEG
Nonspatial Sink Data	SECARB.COAL_AUGUSTA	Table	AUGUSTA
	SECARB.OILGAS_AUGUSTA	Table	AUGUSTA

Figure 1-3 National Parks and State and Local Parks in the Continental United States

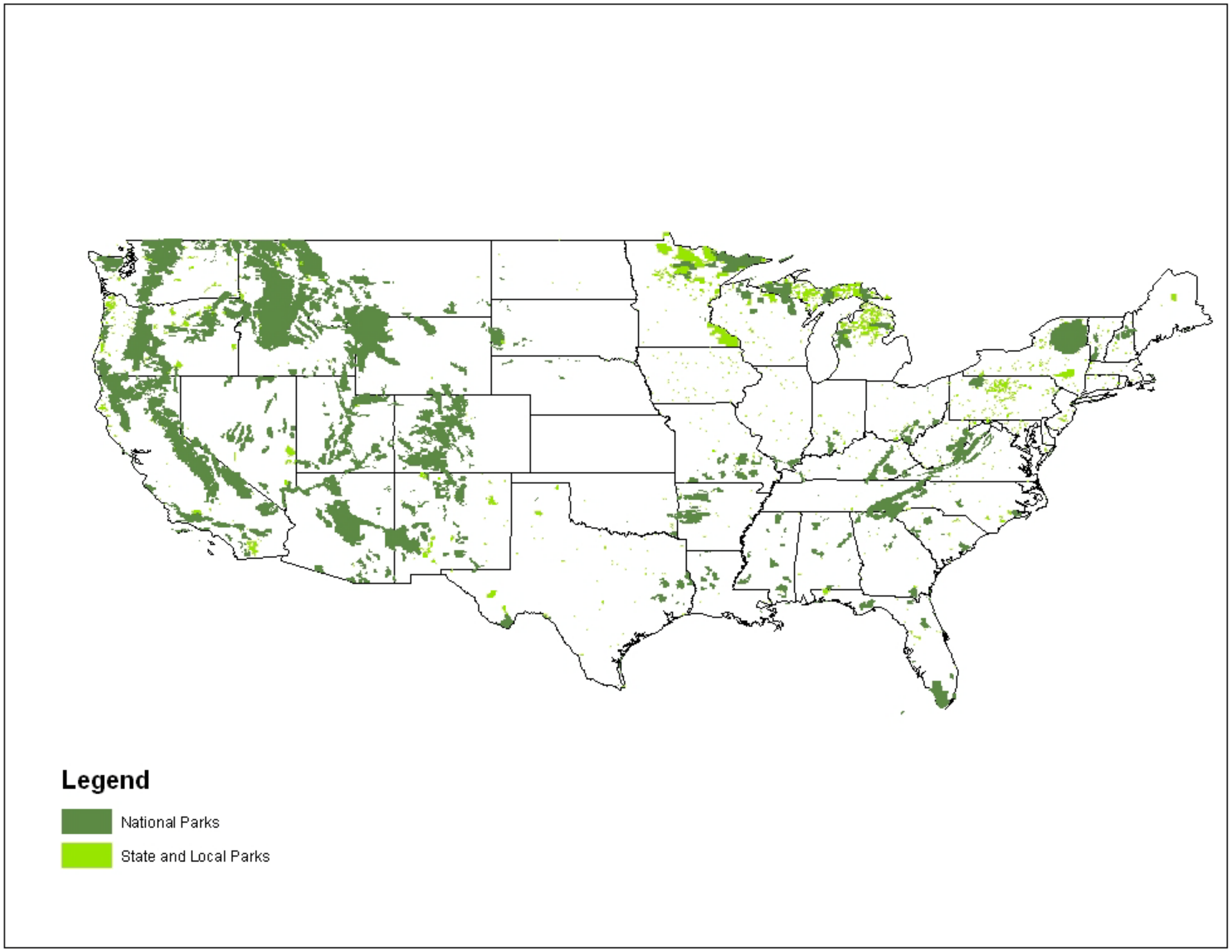


Figure 1-4 Inventoried Roadless Areas in the Continental United States

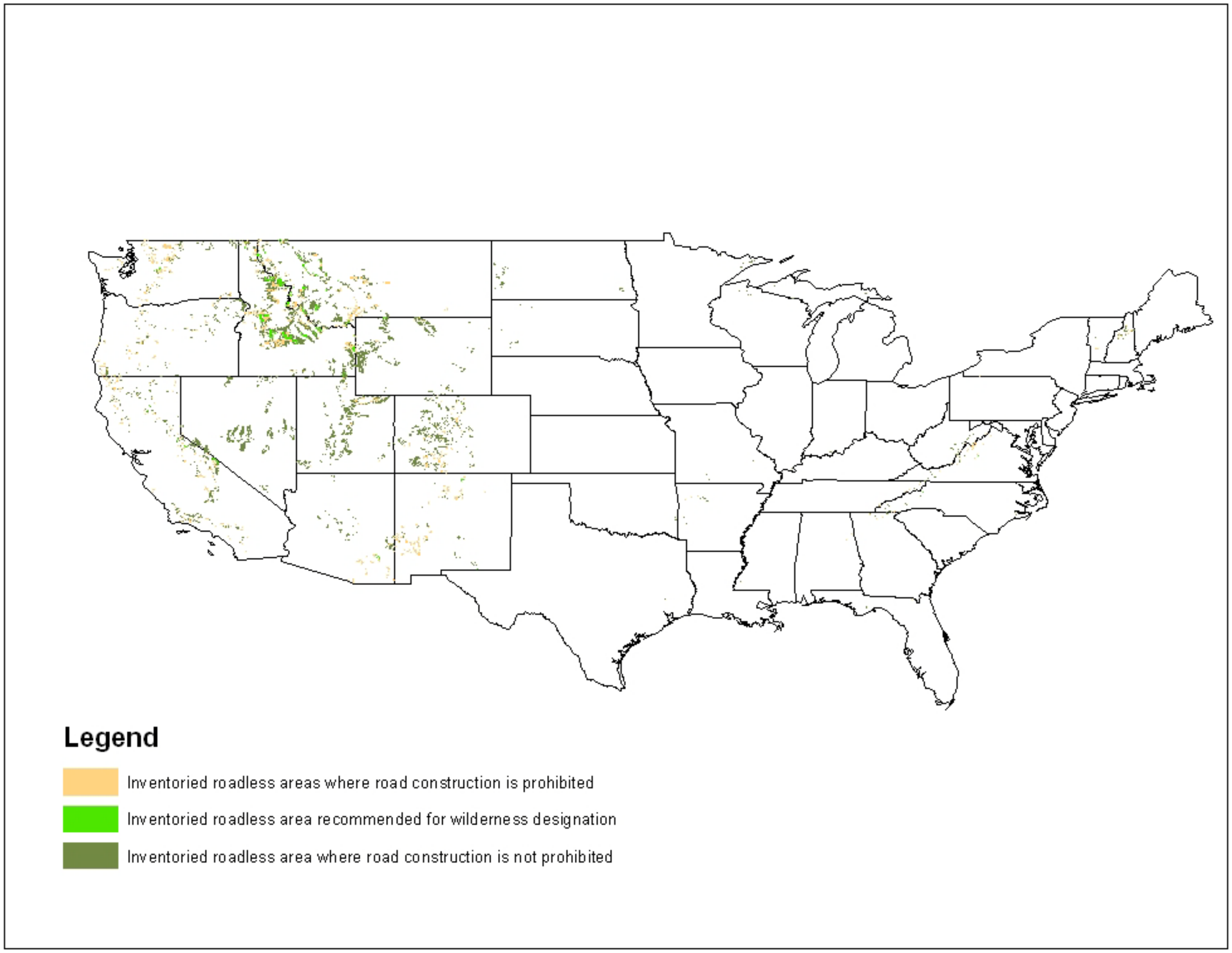


Figure 1-5 Wilderness Areas in the Continental United States

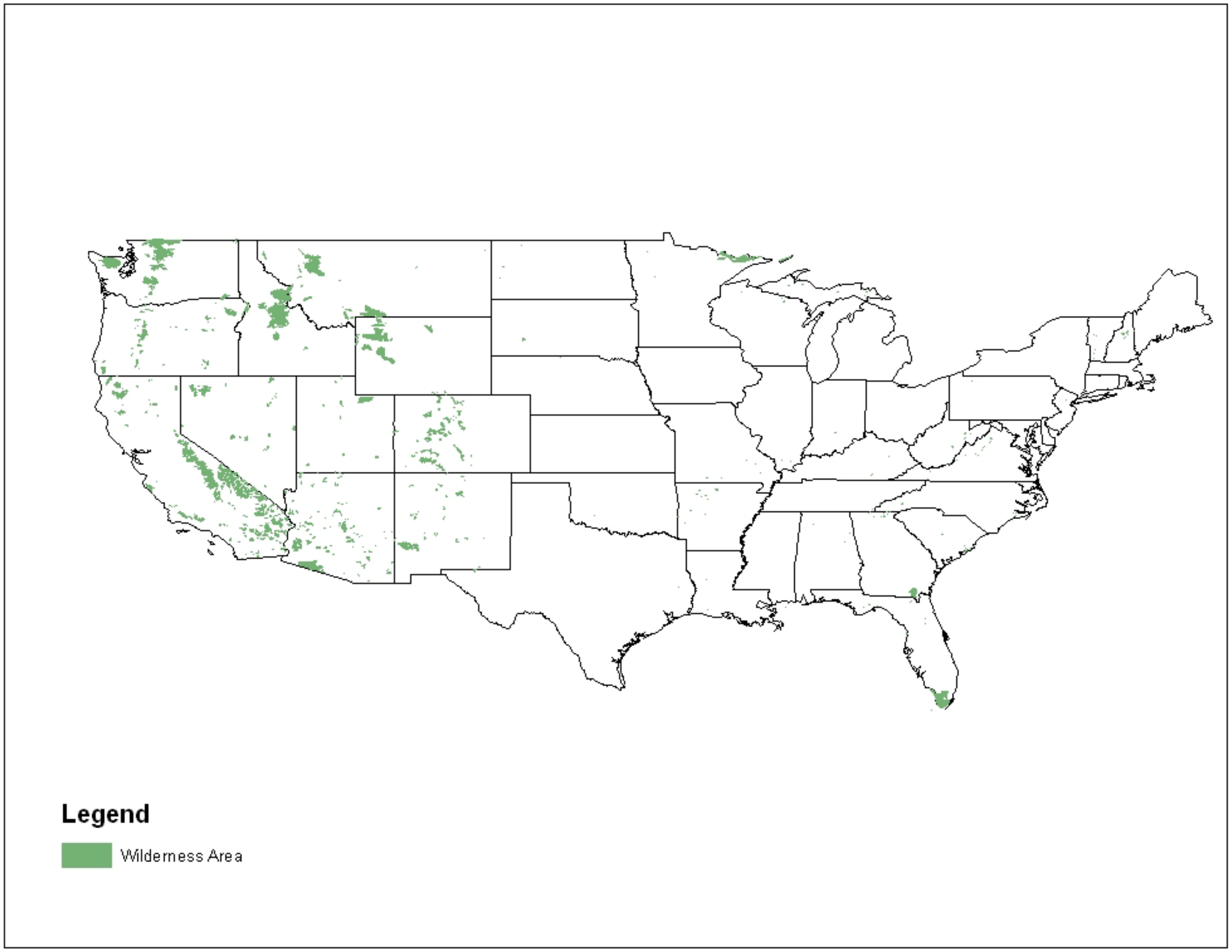


Figure 1-6 Federal Land in the Continental United States

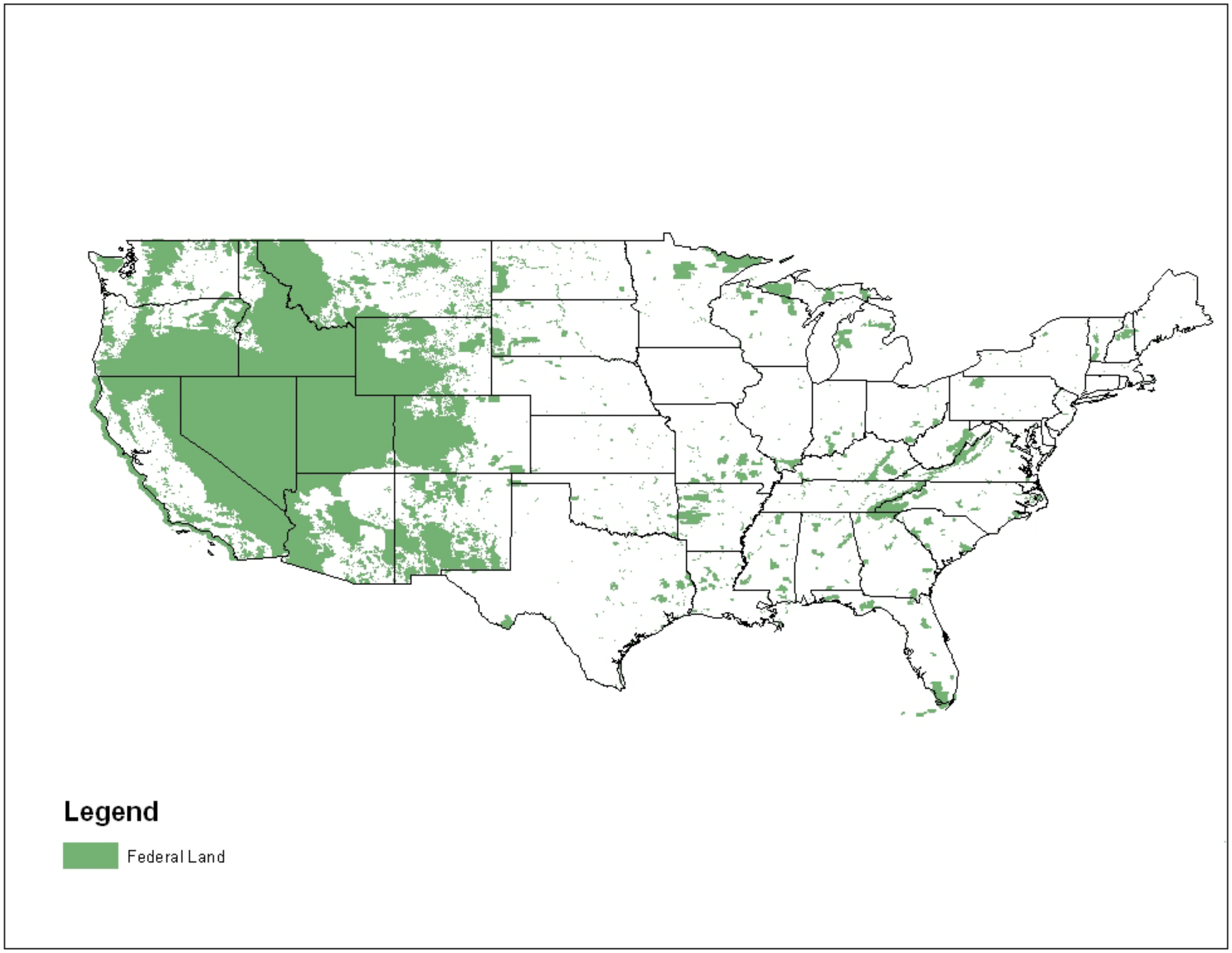


Figure 1-7 State Categories Characterized by the Underground Injection Control Program in the Continental United States

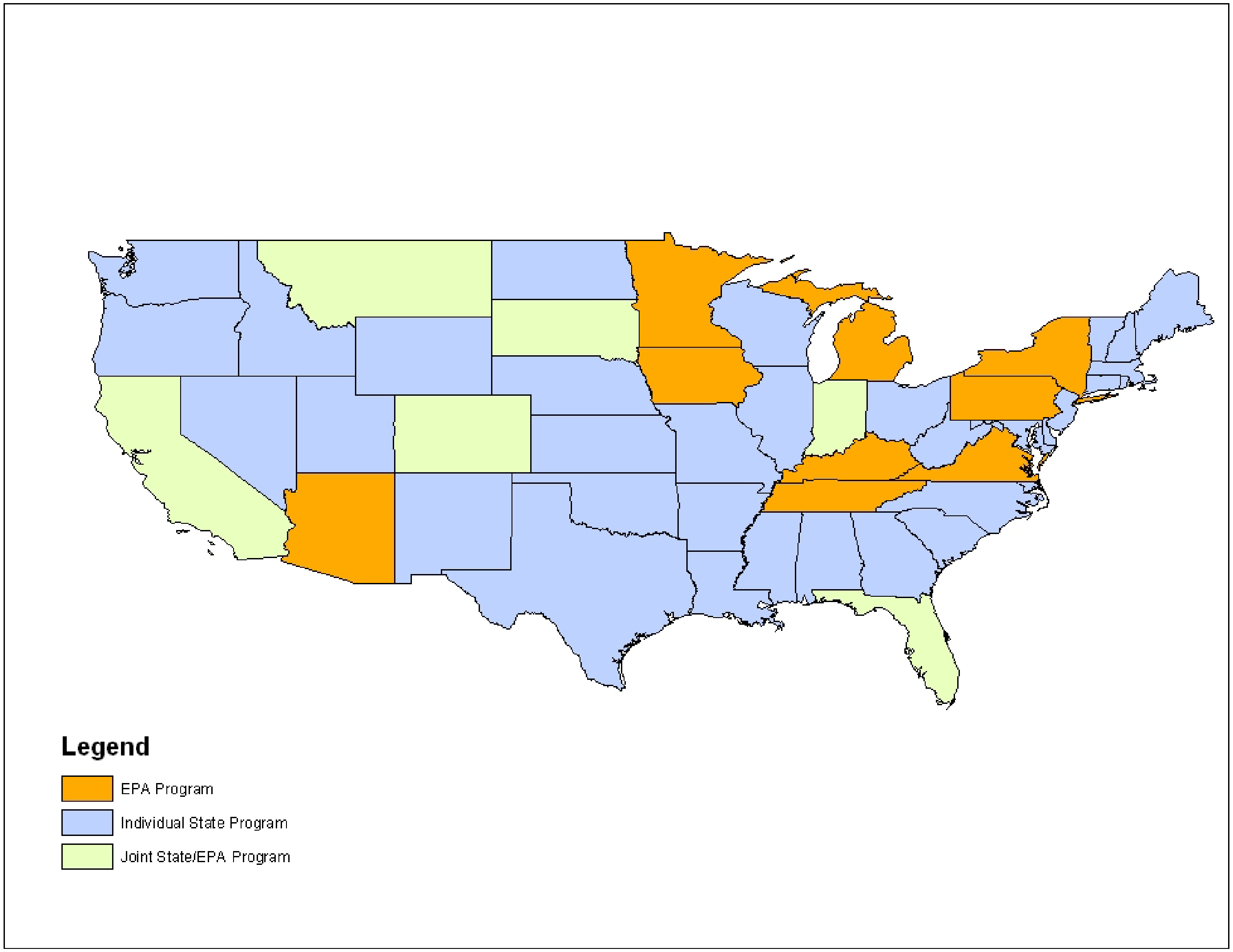


Figure 1-8 State Categories Characterized by Climate Change Action in the Continental United States

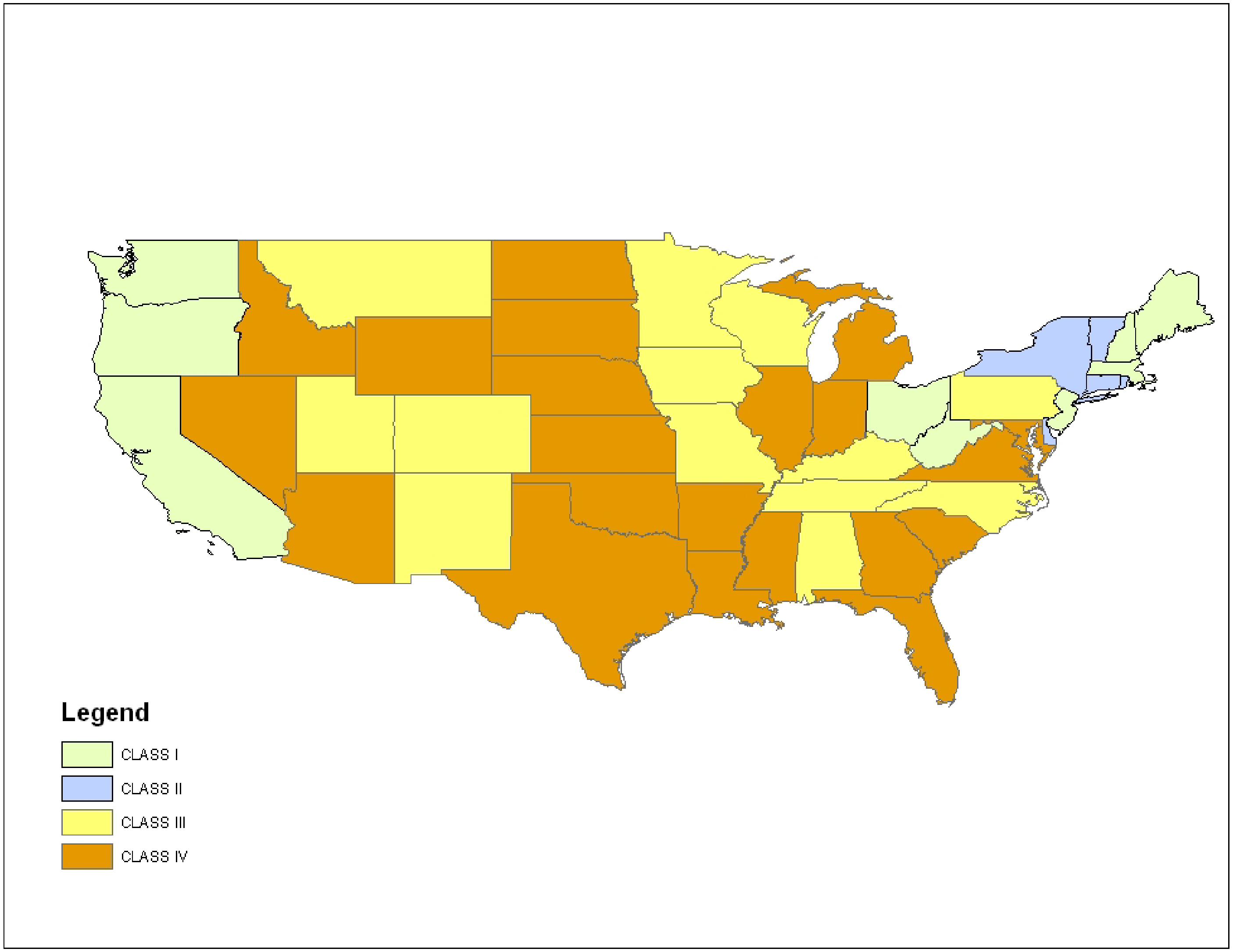


Figure 1-9 Fossil Power Plants in the Continental United State: by Fossil Type and Annual CO_2 Emission

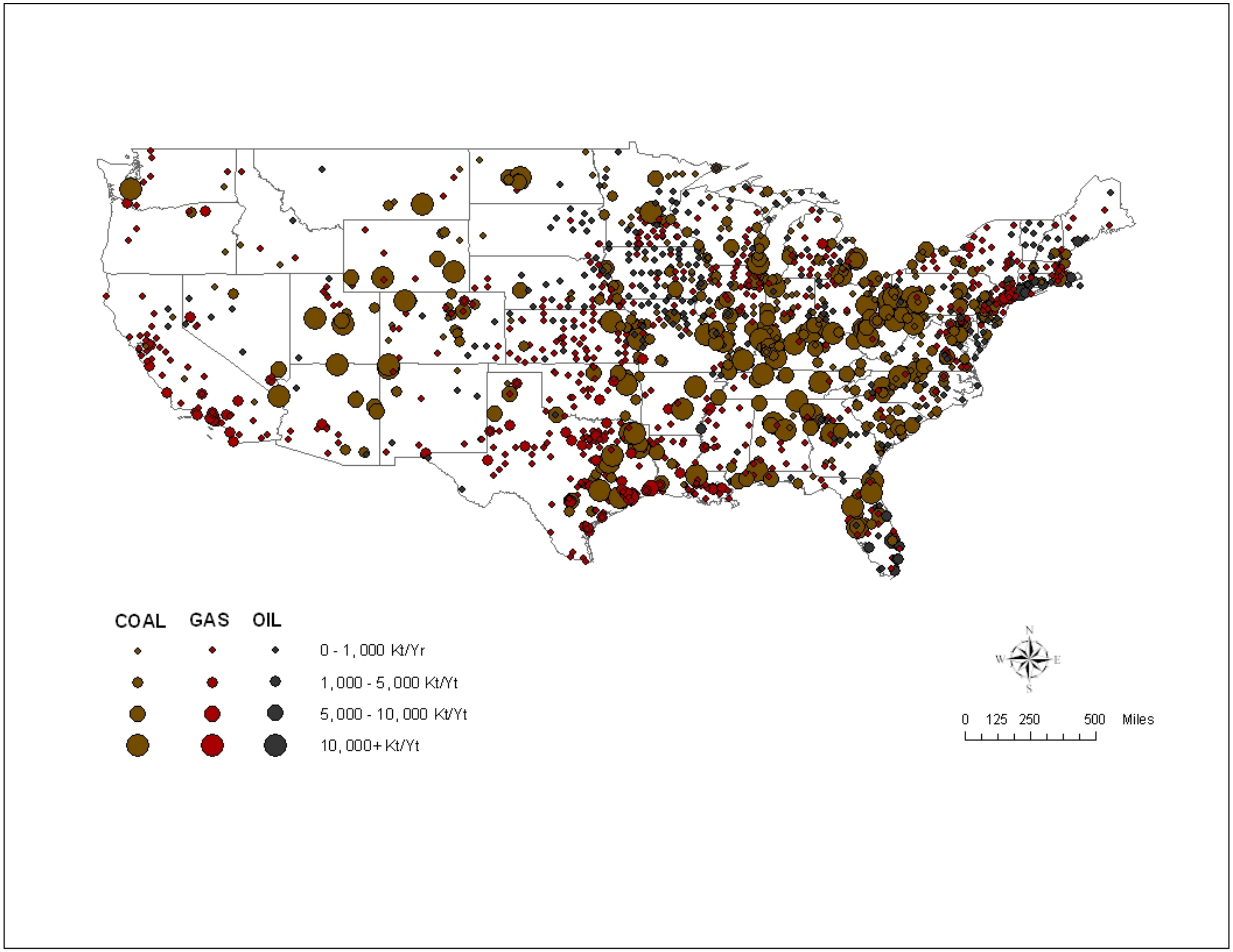


Figure 1-10 Non-power Stationary CO_2 Sources in the Continental United State

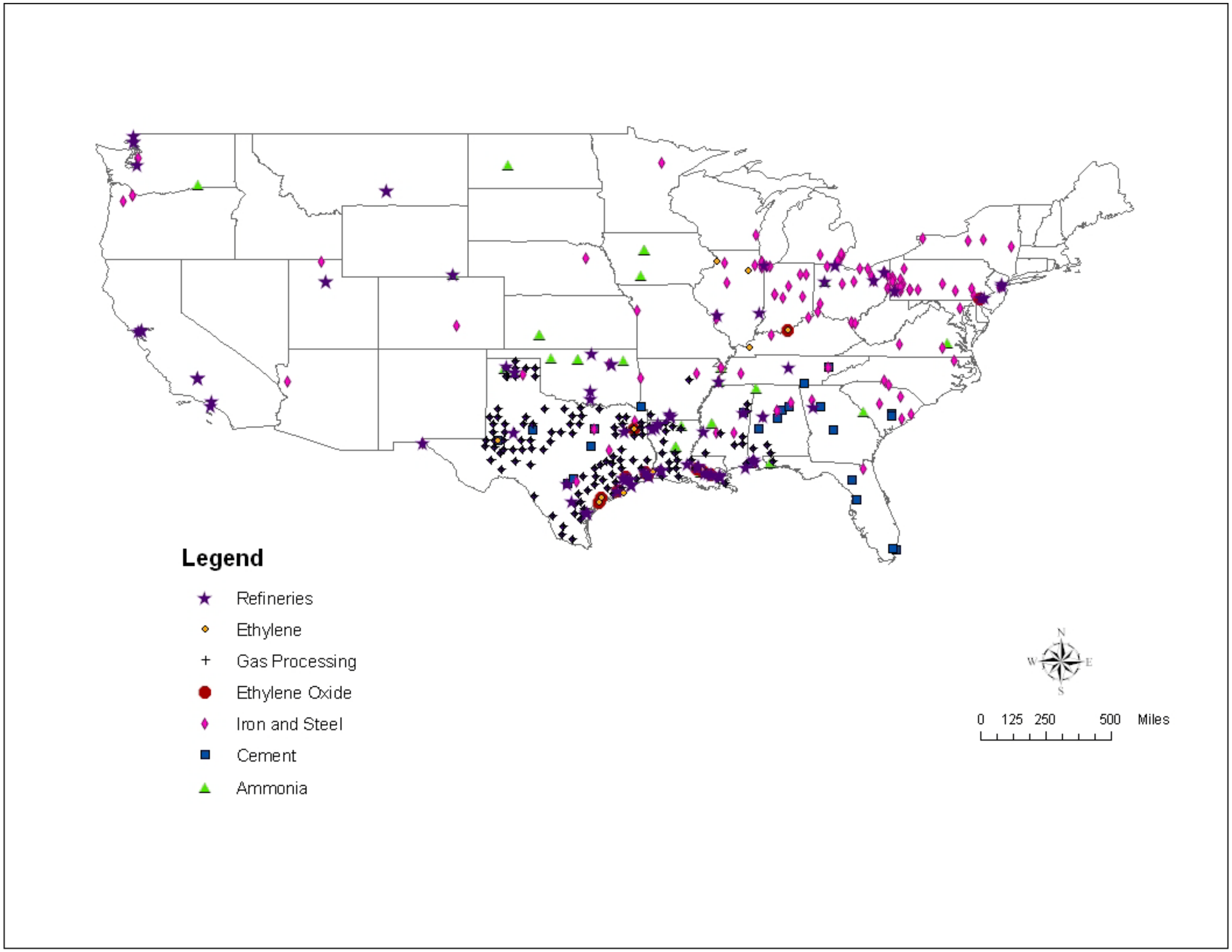


Figure 1-11 Aquifer and Brine Wells for the Continental United States

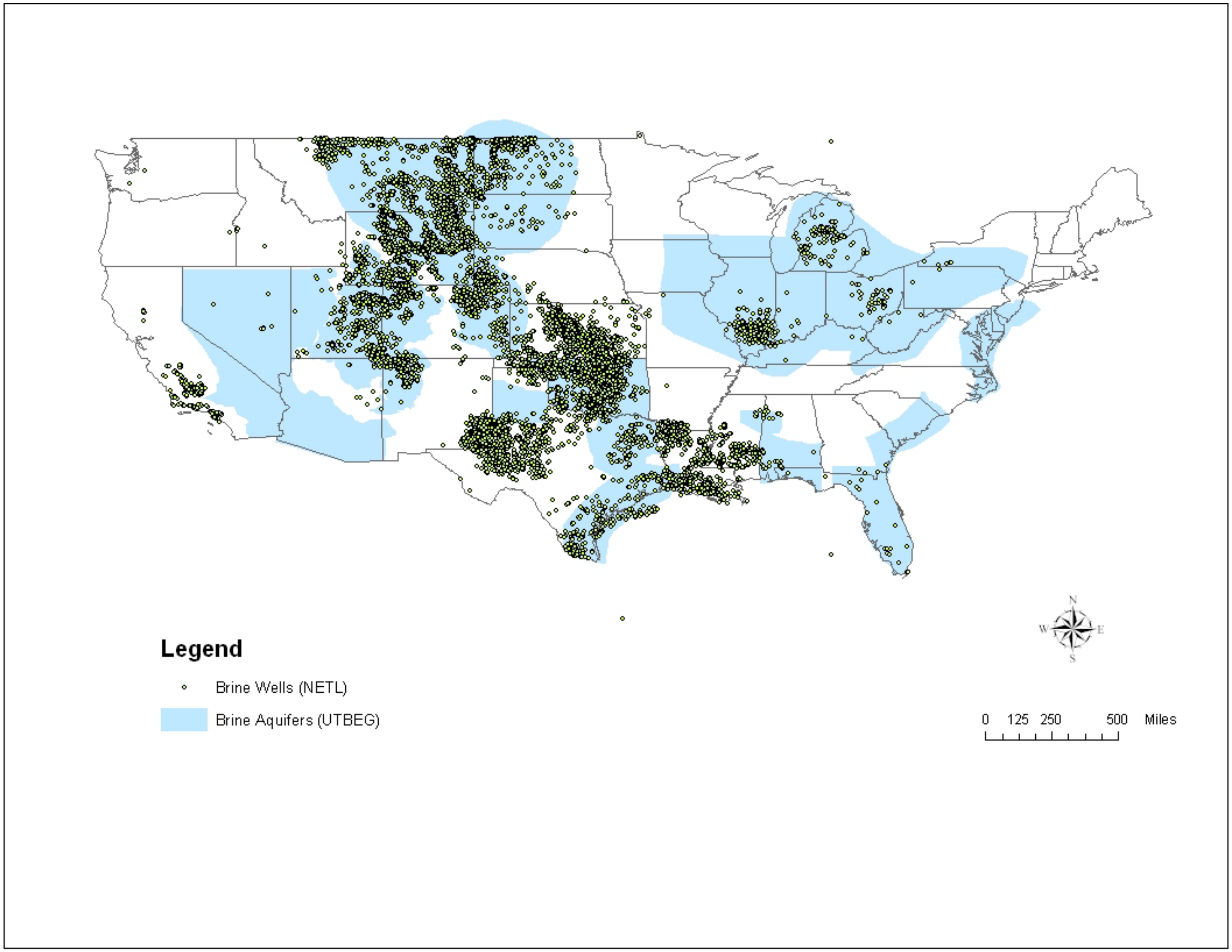


Figure 1-12 Coal Data for the Continental United States

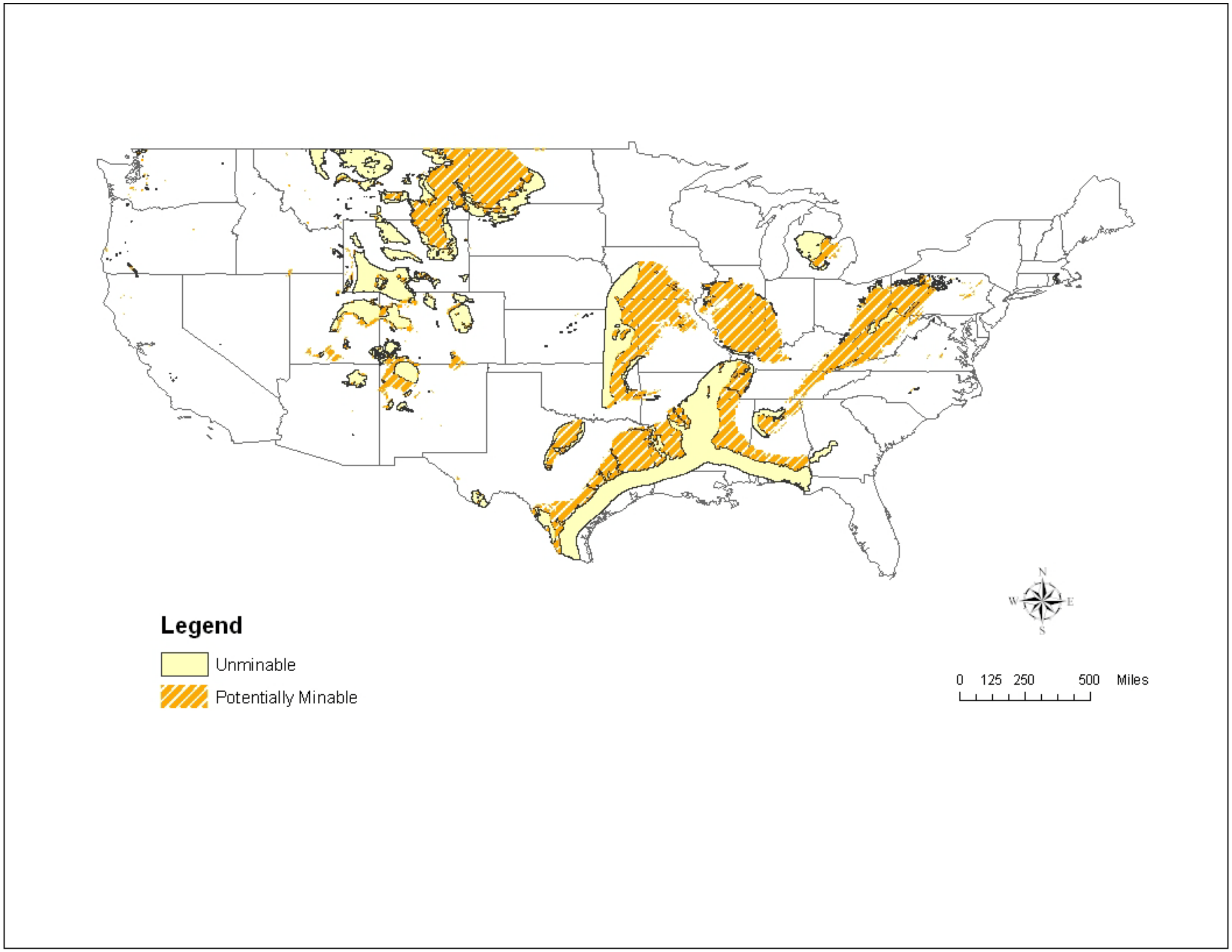
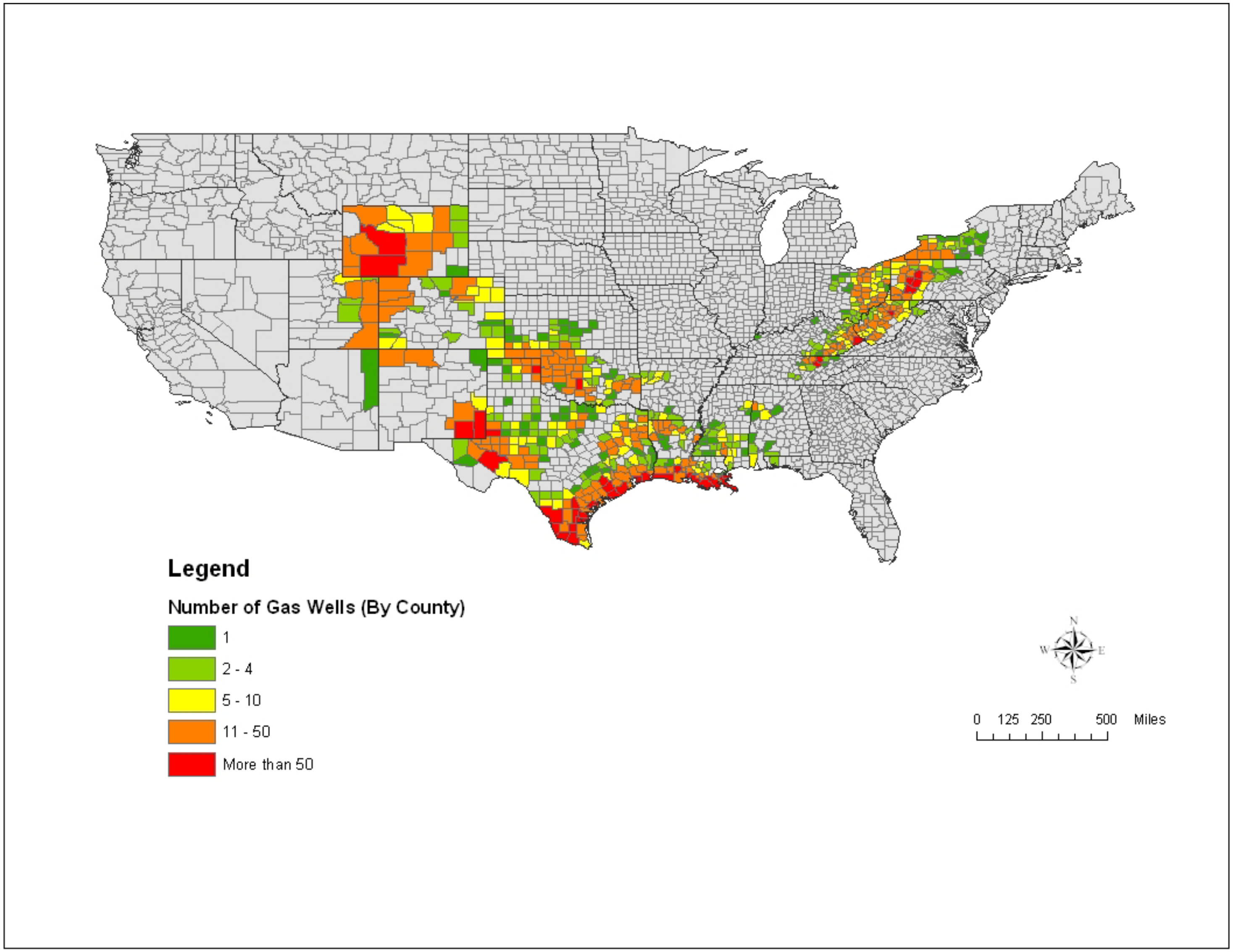


Figure 1-13 Counties in the Continental United States: Classified by Number of GASIS Wells



1.7 Appendix 1-A System Configuration Information

Server 1 (Internet Server)

Network Properties:

Hostname: E40-HJH-SERVER1.MIT.EDU
IP ADDRESS: 18.172.4.89
SUBNET: 255.255.0.0
Gateway: 18.172.0.1
Primary DNS: 18.70.0.160
Secondary DNS: 18.71.0.151

Installation procedure:

1. Install OS: Red Hat Enterprise Linux AS Release 4
2. Install ArcIMS 9.1
3. Install MySQL 5.0.26
4. Install PHP 5.0

Server 2 (Database Server)

Network properties:

Hostname: E40-HJH-SERVER2.MIT.EDU
IP ADDRESS: 18.172.4.90
SUBNET: 255.255.0.0
Gateway: 18.172.0.1
Primary DNS: 18.70.0.160
Secondary DNS: 18.71.0.151

Installation procedure:

1. Install OS: Red Hat Enterprise Linux ES Release 3
2. Install Database: Oracle 9i Enterprise
3. Install SDE software: ESRI ArcSDE 4.2

Server 3 (Backup Server)

Network properties:

Hostname: E40-HJH-SERVER3.MIT.EDU
IP ADDRESS: 18.172.4.228
SUBNET: 255.255.0.0
Gateway: 18.172.0.1
Primary DNS: 18.70.0.160
Secondary DNS: 18.71.0.151

Installation procedure:

1. Install OS: Red Hat Enterprise Linux AS 4
2. Install Database: Oracle 10i Enterprise
3. Install SDE software: ESRI ArcSDE 9.1
4. Install ArcIMS 9.1

E40-481-1 (Main Workstation)
Network properties:
Hostname: E40-481-1.MIT.EDU
IP: 18.172.3.141
Subnet Mask: 255.255.0.0
Gateway: 18.172.0.1
DNS1: 18.70.0.161
DNS2: 18.70.0.151

Installation procedure:

1. Preinstalled version of Windows XP Professional
2. Install ArcIMS

1.8 Appendix 1-B System Installation Documentation

Appendix 1-B.1 – Installation of Red Hat Enterprise Linux (RHEL) ES Release 4

Installed on: E40-HJH-SERVER1, E40-HJH-SERVER3

Among the three servers, server 1 (E40-HJH-SERVER1) and server 3 (E40-HJH-SERVER3) are updated from Linux ES 3 to ES 4. The following procedures were used for the update during July 2006.

URL: http://web.mit.edu/rhel-doc/4/RH-DOCS/rhel-ig-x8664-multi-en-4/index.html

Appendix 1-B.2 Installation of Red Hat Enterprise Linux (RHEL) ES Release 3

Installed on: E40-HJH-SERVER2

Server 2 (E40-HJH-SERVER2) provides stable database services all along. The following is the procedure that was used in the initial installation of the GIS servers during March, 2004.

URL: http://www.redhat.com/now
Product ID: 8d29-65b7-67ad-5313

1. Insert Installation Disk 1 and turn on power
    a. Install Type
        i. Select Graphical Installation
    b. Welcome
        i. Click Next
    c. Language Selection
        i. Select English
        ii. Click Next
    d. Keyboard
        i. Select U.S. English
        ii. Click Next
    e. Mouse Configuration
        i. Select Generic, 2 Button Mouse (PS/2)
        ii. Click Next
    f. Disk Partitioning Setup
        i. Select Automatic Partition
        ii. Click Next
    g. Automatic Partitioning
        i. Select Remove all partitions on this system
        ii. Click Next
        iii. At Warning Popup, Click Yes
    h. Partitioning
        i. Click Next
    i. Boot Loader Configuration
        i. Click Next
    j. Network Configuration
        i. In Network Devices submenu, Check eth0
            1. Click Edit
            2. Uncheck Configure using DHCP
            3. Edit IP ADDRESS using network settings
            4. Edit SUBNET: 255.255.0.0
        ii. In Hostname Submenu
            1. Edit hostname using network settings

iii. In Miscellaneous Settings
1. Edit Gateway: 18.172.0.1
2. Edit Primary DNS: 18.70.0.160
3. Secondary DNS: 18.71.0.151
iv. Click Next
k. Firewall
i. Click Next
l. Additional Language Support
i. Check English (USA)
ii. Click Next
m. Time Zone Selection
i. Select America/New_York
ii. Click Next
n. Set Root Password
i. Set Root Password
ii. Click Next
o. <No Title>
i. Select Accept the current package list
ii. Click Next
p. About to Install
i. ClickNext
2. At Change CD-ROM Popup
a. Insert Disk 2 into CD Drive
b. Click OK
3. At Change CD-ROM Popup
a. Insert Disk 3 into CD Drive
b. Click OK
4. At Change CD-ROM Popup
a. Insert Disk 4 into CD Drive
b. Click OK
5. At Change CD-ROM Popup
a. Insert Disk 1 into CD Drive
b. Click OK
c. Graphical Interface (X) Configuration
i. Click Next
d. Monitor Configuration
i. Click Next
e. Customize Graphical Configuration
i. Click Next
f. Congratulations
i. Click Exit
6. Post installation should begin
a. Welcome
i. Click Next
b. License Agreement
i. Select Yes

        ii. Click Next
    c. Date and Time
        i. Click Next
    d. User Account
        i. Click Next
    e. Red Hat Network
        i. Click Next
        ii. Red Hat Network Configurations Popup
            1. Click OK
        iii. Question Popup
            1. Click Yes
        iv. Up2Date Popup
            1. Click Forward
            2. Click Forward
            3. Select Use Existing
            4. Click Forward
            5. Edit Profile Name: E40-HJH-SERVER.MIT.EDU
            6. Uncheck Include information
            7. Click Forward
            8. Click Forward
    f. Additional CDs
        i. Click Next
    g. Finish Setup
        i. Click Next

At this point RHEL is installed, and most of the configuration can be done remotely through Secure Shell (SSH).

Appendix 1-B.3 Installation of Oracle 10i Enterprise Database

Installed on: E40-HJH-SERVER3

In July 2006, E40-HJH-SERVER3 was set up and Oracle 10i was installed for test purpose and backup service. Since 10i, Oracle database can be downloaded directly from Oracle official website, and do not need site license for usage any more. Following procedures describe the installation procedures of Oracle 10i.

Software Download URL:
http://www.oracle.com/technology/software/products/database/oracle10g/index.htmlURL
Installation Instruction URL:
http://www.oracle-base.com/articles/10g/OracleDB10gR2InstallationOnRedHatAS4.php

Download Software
Download the following software:

- Oracle Database 10g Release 2 (10.2.0.1) Software

Unpack Files
Unzip the files:

```
unzip 10201_database_linux32.zip
```

You should now have a single directory containing installation files. Depending on the age of the download this may either be named "db/Disk1" or "database".

Hosts File

The /etc/hosts file must contain a fully qualified name for the server:

```
<IP-address>  <fully-qualified-machine-name>  <machine-name>
```

Set Kernel Parameters

Add the following lines to the /etc/sysctl.conf file:

```
kernel.shmall = 2097152
kernel.shmmax = 2147483648
kernel.shmmni = 4096
# semaphores: semmsl, semmns, semopm, semmni
kernel.sem = 250 32000 100 128
fs.file-max = 65536
net.ipv4.ip_local_port_range = 1024 65000
net.core.rmem_default=262144
net.core.rmem_max=262144
net.core.wmem_default=262144
net.core.wmem_max=262144
```

Run the following command to change the current kernel parameters:

```
/sbin/sysctl -p
```

Add the following lines to the /etc/security/limits.conf file:

```
*               soft    nproc   2047
*               hard    nproc   16384
*               soft    nofile  1024
*               hard    nofile  65536
```

Add the following line to the /etc/pam.d/login file, if it does not already exist:

```
session    required     /lib/security/pam_limits.so
```

Note by Kent Anderson: In the event that pam_limits.so cannot set privilidged limit settings see Bug 115442.

Disable secure linux by editing the /etc/selinux/config file, making sure the SELINUX flag is set as follows:

```
SELINUX=disabled
```

Alternatively, this alteration can be done using the GUI tool (Applications > System Settings > Security Level). Click on the SELinux tab and disable the feature.

Setup

Install the following packages:

```
# From RedHat AS4 Disk 2
cd /media/cdrom/RedHat/RPMS
rpm -Uvh setarch-1*
rpm -Uvh compat-libstdc++-33-3*
rpm -Uvh make-3*
rpm -Uvh glibc-2*

# From RedHat AS4 Disk 3
cd /media/cdrom/RedHat/RPMS
rpm -Uvh openmotif-2*
rpm -Uvh compat-db-4*
rpm -Uvh libaio-0*
rpm -Uvh gcc-3*

# From RedHat AS4 Disk 4
```

```
cd /media/cdrom/RedHat/RPMS
rpm -Uvh compat-gcc-32-3*
rpm -Uvh compat-gcc-32-c++-3*
```

Create the new groups and users:

```
groupadd oinstall
groupadd dba
groupadd oper

useradd -g oinstall -G dba oracle
passwd oracle
```

Create the directories in which the Oracle software will be installed:

```
mkdir -p /u01/app/oracle/product/10.2.0/db_1
chown -R oracle.oinstall /u01
```

Login as root and issue the following command:

```
xhost +<machine-name>
```

Login as the oracle user and add the following lines at the end of the .bash_profile file:

```
# Oracle Settings
TMP=/tmp; export TMP
TMPDIR=$TMP; export TMPDIR

ORACLE_BASE=/u01/app/oracle; export ORACLE_BASE
ORACLE_HOME=$ORACLE_BASE/product/10.2.0/db_1; export ORACLE_HOME
ORACLE_SID=TSH1; export ORACLE_SID
ORACLE_TERM=xterm; export ORACLE_TERM
PATH=/usr/sbin:$PATH; export PATH
PATH=$ORACLE_HOME/bin:$PATH; export PATH

LD_LIBRARY_PATH=$ORACLE_HOME/lib:/lib:/usr/lib; export LD_LIBRARY_PATH
CLASSPATH=$ORACLE_HOME/JRE:$ORACLE_HOME/jlib:$ORACLE_HOME/rdbms/jlib; export
CLASSPATH
#LD_ASSUME_KERNEL=2.4.1; export LD_ASSUME_KERNEL

if [ $USER = "oracle" ]; then
  if [ $SHELL = "/bin/ksh" ]; then
    ulimit -p 16384
    ulimit -n 65536
  else
    ulimit -u 16384 -n 65536
  fi
fi
```

Installation

Log into the oracle user. If you are using X emulation then set the DISPLAY environmental variable:

```
DISPLAY=<machine-name>:0.0; export DISPLAY
```

Start the Oracle Universal Installer (OUI) by issuing the following command in the database directory:

./runInstaller

During the installation enter the appropriate ORACLE_HOME and name then continue installation. For a more detailed look at the installation process, click on the links below to see screen shots of each stage.

1. Select Installation Method
2. Specify Inventory Directory and Credentials
3. Select Installation Type
4. Specify Home Details
5. Product-Specific Prerequisite Checks
6. Select Configuration Option
7. Select Database Configuration
8. Specify Database Configuration Options
9. Select Database Management Option
10. Specify Database Storage Option
11. Specify Backup and Recovery Options
12. Specify Database Schema Passwords
13. Summary
14. Install
15. Configuration Assistants
16. Database Configuration Assistant
17. Database Configuration Assistant Password Management
18. Execute Configuration Scripts
19. End Of Installation

Post Installation

Edit the /etc/oratab file setting the restart flag for each instance to 'Y':

```
TSH1:/u01/app/oracle/product/10.2.0/db_1:Y
```

For more information see:

- Installation Guide for Linux x86 (10.2)
- Installing Oracle Database 10g Release 1 and 2...
- Automating Database Startup and Shutdown on Linux

Appendix 1-B.4 Installation of Oracle 9i Enterprise Database

Installed on: E40-HJH-SERVER2

The Oracle database was selected because MIT has site licenses and considerable support available for Oracle users.

URL: http://www.oracle-base.com/articles/9i/Oracle9iInstallationOnRedHatAS3.php
URL: http://download-east.oracle.com/docs/html/A96167_01/pre.htm

In the following instructions, `<username>%` is used to indicate that a command should be run in the server while logged in under the specified username.

1. Pre-installation procedures
   a. Login as root
   ```
   root% cd /proc/sys/kernel
   root% echo 250 32000 128 128 > sem
   root% echo 268435456 > shmmax
   root% echo 65536 > /proc/sys/fs/file-max
   root% ulimit -n 65536
   ```

```
root% echo 1024 65000 > /proc/sys/net/ipv4/ip_local_port_range
root% ulimit -u 16384
root% groupadd -r dba
root% groupadd oinstall
root% groupadd oper
root% useradd -c "Oracle Software" -g oinstall -G dba -n oracle
root% passwd oracle
<enter password>
root% useradd -c "Oracle IAS" -g oinstall -G apache -n oias
root% passwd oias
<enter password>
root% mkdir -p /u01/app/oracle/product/9.2.0.1.0
root% chown -R oracle.oinstall /u01
root% ln -s /usr/bin/gcc296 /usr/bin/gcc
root% ln -s /usr/bin/cc /usr/bin/gcc
root% ln -s /usr/bin/g++296 /usr/bin/g++
root% cd /tmp/oracle_patches/
root% unzip p3006854_9204_LINUX.zip
root% cd 3006854
root% sh rhel3_pre_install.sh
```

b. Login as oracle

```
oracle% vi $HOME/.bash_profile
<Insert text according to directions>
oracle% source $HOME/.bash_profile
```

2. Installation
   a. Login as oracle

   ```
   oracle% /mnt/cdrom/runInstaller
   ```

   b. At popup Error: ins_oemagent.mk
   c. Goto shell

   ```
   oracle% cd /tmp/oracle_patches/
   oracle% unzip p3119415_9203_LINUX.zip
   oracle% cd 3119415
   oracle% sh patch.sh
   ```

   d. Login as root

   ```
   root% sh /u01/app/oracle/product/9.2.0.1.0/root.sh
   ```

3. Patch the Installation
   a. Update the Universal Installer

   ```
   oracle% cd /tmp/oracle_patches/9204/Disk1/
   oracle% ./runInstaller
   ```

   b. Patch the database

   ```
   oracle% ./runInstaller
   root% sh /u01/app/oracle/product/9.2.0.1.0/root.sh
   ```

4. Configure the database

```
oracle% vi ~/.bash_profile
export ORACLE_SID=ccstp
export THREADS_FLAG=native
oracle% dbca
  Global Name: ccstp
oracle% cp
/u01/app/oracle/admin/ccstp/pfile/initccstp.ora.211200416742
/u01/app/oracle/product/9.2.0/dbs/initccstp.ora
oracle% netca
  Listener Configuration
  Add
  LISTENER
```

```
      Selected Protocols: TCP
      Use the standard port number of 1521
    oracle% cp /u01/app/oracle/product/9.2.0/root.sh
/u01/app/oracle/product/9.2.0/root.sh.20040311
```

5. Set up initialization script

```
root% vi /etc/services
LISTENER    1521/tcp          # Oracle Net Listener
root% redhat-config-systemlevel-tui
root% vi /etc/init.d/dbora
#!/bin/sh
# chkconfig 03 99 10
# description: Start and stop Oracle 9i database and listener
# Set ORA_HOME to be equivalent to the $ORACLE_HOME
# from which you wish to execute dbstart and dbshut;
#
# Set ORA_OWNER to the user id of the owner of the
# Oracle database in ORA_HOME.
ORA_HOME=/u01/app/oracle/product/9.2.0.1.0
ORA_OWNER=oracle
case "$1" in
     'start')

    # Start the Oracle databases:
    # The following command assumes that the oracle login
    # will not prompt the user for any values

     echo -n "Starting Oracle:"
     su - $ORA_OWNER -c "$ORA_HOME/bin/dbstart ccstp"
     su - $ORA_OWNER -c "$ORA_HOME/bin/lsnrctl start listener"
     ;;

     'stop')

    # Stop the Oracle databases:
    # The following command assumes that the oracle login
    # will not prompt the user for any values

     echo -n "Stopping Oracle:"
     su - $ORA_OWNER -c "$ORA_HOME/bin/dbshut ccstp"
     su - $ORA_OWNER -c "$ORA_HOME/bin/lsnrctl stop listener"
     ;;
     'restart')
     echo -n "Restarting Oracle:"
     $0 stop
     $0 start
     echo
     ;;
     *)
     echo "Usage: dbora (start | stop | restart)"
     exit 1
esac
root% chkconfig --add dbora
```

Appendix 1-B.5 Installation of ArcSDE 4.2

Installed on: E40-HJH-SERVER2

The ArcSDE program has been added to the database server in order to allow connections between ArcGIS software and the Oracle Database.

1. Copy SDE files onto server
    a. FTP the /redhat directory of the ArcSDE software CD onto the server
2. Edit the SDE environment
```
sde% vi .bash.profile
```
3. To fix sdesetupora9i segmentation fault
```
sde% export LD_ASSUME_KERNEL=2.4.19
```
4. Install ArcSDE
```
sde% ./arcsde/install -load
  [/cdrom] /home/sde/arcsde
  [/home/sde/arcsde] /u01/app/esri
  [all] <Enter>
  [yes] <Enter>
  [no] <Enter>
```
5. Patch
```
sde% ./arcsde/patch/apply_patch
  (y): y
  (u01/app/esri/sdeexe82): <Enter>
  [1,2,3,4,5,6]: 6
  (y): n
  (y): y
  Press enter... <Enter>
```
6. Run Post install
```
sde% sdesetupora9i -o install -p <password>
```
7. Set up SDE Roles in database

    <login to database>
```
create role SDE_VIEWER;
create role SDE_EDITOR;
create role SDE_NEWUSER;
create role SDE_CREATOR;
create role SDE_APPLICATION;
create role SDE_UPGRADE;

grant create session
to    SDE_VIEWER;

grant create session
to    SDE_EDITOR;

grant SDE_VIEWER,
      create table, create procedure, create sequence,
      create trigger
to    SDE_NEWUSER;

grant create session, create table,
      create procedure, create sequence,
      create trigger
to    SDE_CREATOR;

grant select any table, create session, create table,
      create any procedure, create any sequence, create trigger
```

```
to    SDE_APPLICATION;

grant ALTER ANY INDEX, ALTER ANY TABLE,
      ANALYZE ANY, CREATE ANY INDEX,
      create any procedure, create any sequence,
      create any trigger, create any view,
      CREATE SESSION, DROP ANY INDEX, drop any view,
      drop any procedure, drop any sequence,
      execute any procedure,
      select any sequence, select any table
to    SDE_UPGRADE;
```

8. Set up initialization script

```
root% vi /etc/init.d/esri_sde
#!/bin/sh
# chkconfig: 35 99 10
# description: Starts and stops ESRI SDE Monitor

# Set SDE_HOME to be equivalent to the $SDEHOME
# from which you wish to execute sdemon;
#
# Set SDE_OWNER to the user id of the SDE Administrator.

SDE_HOME=/u01/app/esri/sdeexe82/
SDE_OWNER=sde

case "$1" in
     'start')

          # Start the SDE Monitor:
          # The following command assumes that the oracle login
          # will not prompt the user for any values
           echo -n "Starting SDE Server: "
     su - $SDE_OWNER -c "$SDE_HOME/bin/sdemon -o start -p tg43ru9"
     ;;

     'stop')

          # Stop the SDE Monitor:
          # The following command assumes that the oracle login
          # will not prompt the user for any values

     echo -n "Stopping SDE Server: "
     su - $SDE_OWNER -c "$SDE_HOME/bin/sdemon -o shutdown -p tg43ru9"
     ;;

     'restart')
     echo -n "Restarting SDE Server: "
     $0 stop
     $0 start
     echo
     ;;
     *)
     echo "Usage: esri_sde (start | stop | restart)"
     exit 1

esac
```

Appendix 1-B.6 Installation of ArcIMS

Installed on: E40-HJH-SERVER1

ArcIMS is installed on E40-HJH-Server1.MIT.EDU in order to support Internet access to the GIS, including the needs of the Regional Carbon Sequestration Partnerships. The following ESRI documentation for ArcIMS installation on Linux was the primary source of instruction for the installation.
http://support.esri.com/index.cfm?fa=knowledgebase.techarticles.articleShow&d=23695

1. Install Java 2 SDK
    a. Installed version is 1.4.2_06
    b. Install location: JAVA_HOME = /usr/java/j2sdk1.4.2_06
2. Install Apache
    a. Installed version is 2.0.52 (httpd-2.0.52.tar.gz)
    b. Install location: APACHE_HOME=/var/www
3. Configure Apache
    a. Edit /etc/httpd/conf/httpd.conf
    ServerName E40-HJH-Server1:80
4. Install Jakarta-Tomcat
    a. Installed version is 4.1.31
    b. Install location CATALINE_HOME=/usr/local/tomcat/jakarta-tomcat-4.1.31
5. Configure Apache for Tomcat
    a. Download and install mod_jk-2.0.42.so
    > mv mod_jk-2.0.42.so $APACHE_HOME/modules/mod_jk.so
    > chmod 755 $APACHE_HOME/modules/mod_jk.so
    b. Download and install workers.properties
    > cp workers.properties $CATALINA_HOME/conf
    > vi $CATALINA_HOME/conf/workers.properties
        Worker.ajp13.host=18.172.4.89
    c. Download and install mod_jk.conf
    > cp mod_jk.conf $CATALINA_HOME/conf
    d. Configure $CATALINA_HOME/conf/web.xml and uncomment the <servlet> and <servlet-mapping> blocks for servlet named invoker
    e. Add line to $APACHE_HOME/conf/httpd.conf
    Include /usr/local/tomcat/jakarta-tomcat-4.1.31/conf/mod_jk.conf
6. Install ArcIMS from CD
    a. Installed using user: esri
    b. Installed to /home/esri/bin/arcims4/
7. Configure ArcIMS
    a. Set up Tomcat classes directory
    mkdir $CATALINA_HOME/webapps/ROOT/WEB-INF/classes
    b. Copy connector files from ArcIMS/Middleware/servlet_connector

1.9 *Appendix 1-C Server Administration and Maintenance*

The servers (E40-HJH-SERVER1.mit.edu and E40-HJH-SERVER2.mit.edu) are configured to be left on at all times. There should be no need to restart the server programs or the server hardware. However, in the case when this is required, the following section gives the procedure for doing that.

ArcIMS Service

Machine Name: E40-HJH-SERVER1.mit.edu
Login as: esri

Start/Stop/Restart
To restart the IMS service, do the following:

a. Logon as *root*
b. Run `/etc/init.d/esri_ims restart`

Apache/Tomcat
Machine Name: E40-HJH-SERVER1.mit.edu
Login as: esri

Start/Stop/Restart
For Apache:

a. Logon as root
b. Run `/etc/init.d/httpd restart`

For Tomcat:

a. Logon as root
b. Run `/etc/init.d/tomcat restart`

The ArcSDE Service

Machine Name: E40-HJH-SERVER2.mit.edu
Login as: root

Start/Stop/Restart
The ArcSDE Service is configured to start and stop automatically during the startup and shutdown of the server. If it is necessary to restart the service, do the following:

a. Logon as *root*
b. Run `/etc/init.d/esri_sde restart`

The Oracle Database

Machine Name: E40-HJH-SERVER2.mit.edu
Login as: root

Start/Stop/Restart
The oracle database is configured to start and stop automatically during the startup and shutdown of the server. If the database becomes unstable, and needs to be restarted, do the following:

a. Logon as *root*
b. Run `/etc/init.d/dbora restart`

Server Machine

*Restart (*CAUTION*)*

Be very careful about restarting the Server, as this will stop all services, and may lose all currently working data. However, if it is necessary to do so, it is very straightforward:

a. Login as *root*
b. Run `reboot`

1.10 Appendix 1-D Database Administration

In using the GIS, it may become necessary to manage the Oracle database directly. Administrative tasks of this sort include the addition of users, granting various accesses to users, and managing the current users, tables, and access requirements. The following sections cover some basic database commands that are useful in administering the database. However, there are various books and online resources on PL/SQL commands that go into greater detail than can be covered in this document.

User Administration

Creating a new user:

New users can be created for each organization providing source data to help organize and partition the data. Additionally, new users can be created for people who would like to access the data in the database.

```
CREATE USER <username>
    IDENTIFIED BY <password>
    DEFAULT TABLESPACE "GIS0"
    TEMPORARY TABLESPACE "TEMP"
    QUOTA 10240 K
    ON "TEMP"
    QUOTA 102400 K
    ON "GIS0"
    ACCOUNT UNLOCK;
```

Create a directory for data:

When there is a need to store data files on the database server, the standard procedure is to create a directory

```
CREATE DIRECTORY D_<username>
   AS '/u01/<username>';
```

Access Administration – Individual users

There are some standard access that can be granted to all users, and other access types that serve specific roles and should be granted only to certain users. Access types can be combined as needed if a user needs them.

For basic connection to the database:

```
GRANT "CONNECT" TO <username>;

GRANT READ ON DIRECTORY D_<username> to <username>;
GRANT WRITE ON DIRECTORY D_<username> to <username>;
```

To grant read access to a particular table:

```
GRANT SELECT ON <tablename> to <username>;
```

Access Administration – Database Roles

Roles are a way to store several different access parameters together and grant them to a user all at once. In our database, roles are used to consolidate access requirements for SDE, users within the group, and external users.

When a user is created who will be connecting to the database via the ArcSDE interface, the following roles should be granted:

```
GRANT SDE_VIEWER TO <username>;
GRANT SDE_NEWUSER TO <username>;
```

After the user connects once, the `SDE_NEWUSER` role may be revoked:

```
REVOKE SDE_NEWUSER FROM <username>;
```

If the user will be creating new tables and shapefiles in the database, an additional role should be granted:

```
GRANT SDE_CREATOR TO <username>;
```

For users within the group, the role CCSTP_VIEWER has been granted `select` on each of the tables that were added to the database

```
GRANT CCSTP_VIEWER TO <username>;
```

For users outside of the group, the role GIS_VIEWER is used and is granted `select` on the tables that are deemed to be public.

```
GRANT GIS_VIEWER TO <username>;
```

When new tables are added to the database, you may want to grant `select` access to relevant roles:

```
GRANT SELECT ON <tablename> to CCSTP_VIEWER;
```

2 Annex 2: Stationary CO_2 Source Database

2.1 Introduction

This annex documents the stationary CO_2 source database that has been updated in June 2009. The database contains the location and capacities of the major stationary sources of CO_2 in the United States. It also includes annual CO_2 emissions. CO_2 emissions from power plants were given in the US Environmental Protection Agency (USEPA) eGRID database. For other CO_2 sources, the emissions were estimated using emissions factors based on annual production.

The database contains the following nine major stationary source categories:

- Power plants
- Ammonia Plants
- Cement plants
- Ethanol
- Ethylene plants
- Ethylene oxide plants
- Gas processing facilities
- Iron & steel plants
- Refineries

In this annex:

- Section 2.2 presents the data sources and CO_2 emissions estimation factors.
- Section 2.3 summarizes the fossil power plants in the database.
- Section 2.4 summarizes each type of non-power stationary CO_2 sources in the database.

2.2 Data Sources and CO_2 Emissions Factors

2.2.1 Facility Data Sources

The USEPA eGRID2007 database was used exclusively for the power plant data in this database. For other major CO_2 sources, the ECOFYS database developed for the IEA GHG program released in 2002 and updated in 2006 was used as an initial starting point. Records within the ECOFYS database were then upgraded using the sources listed in Table 2-1. Specifically, new data sources were used for ammonia plants, cement plants, ethanol plants and refineries. Updated data was also used for gas processing facilities. No changes were made to the data sources for ethylene, ethylene oxide, and iron and steel plants at this time. See Table 2-1 for details on the data sources used for each emissions source category.

The eGRID and ECOFYS databases contain geographic coordinate information for the vast majority of the stationary CO_2 emissions sources. In cases where this data was unavailable, the USGS Geographical Names Information System database (GNIS) was used to lookup the missing data.

Table 2-1 Data Sources

Category	Data Source
Power plants	US Environmental Protection Agency (USEPA) eGRID2007 Database Version 1.1 (released in November, 2008 and revised in February, 2009) http://www.epa.gov/cleanenergy/egrid/index.htm
Ammonia plants	International Fertilizer Development Center Report "North America Fertilizer Capacity" (March, 2009) http://www.ifdc.org/New_Design/Publications/Market_Reports/index.html
Cement plants	NATCARB Cement Database by the Kansas Geological Survey (2006)
Ethanol plants	NATCARB Ethanol Database by the Kansas Geological Survey (2006)
Gas processing facilities	Oil and Gas Journal Worldwide Gas Processing Survey (2006) http://orc.pennnet.com/surveys/aboutsurveys.cfm USGS Organic Geochemistry Database (well CO_2 levels) http://energy.cr.usgs.gov/prov/og/
Refineries	US Department of Energy – Energy Information Administration (June, 2008) http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html
Ethylene plants	*International Survey Of Ethylene From Steam Crackers-2008*, Oil & Gas Journal, July 28, 2008
Ethylene oxide plants	From Ecofys: ChemWeek Website; http://www.chemweek.com, 2001
Iron and steel plants	From Ecofys: *World Steelworks Survey*, SteelEye, 2001

2.2.2 CO_2 Emissions Factors

Only eGRID database gives CO_2 emissions data explicitly. All others are estimated.
The CO_2 emissions data for cement and ethanol plants are already estimated in the databases by NatCarb, while the other data sources in Table 2-1 provide production capacity numbers but do not have information on CO_2 emission rates. In order to convert these capacity numbers to CO_2 emission rates, emission factors for each of the source categories were identified (Table 2-2). It is important to note that the CO_2 emissions estimated from applying these emission factors are very approximate. They are useful for comparing the total emissions from each source type, but may not be an accurate estimate of emissions from any individual source.

Table 2-2 CO_2 Emission Factors

Category	Emission Factor	Units	Source
Power	-	-	CO_2 emissions explicitly given in eGRID database
Ammonia	1.13[3]	kg CO_2/kg Ammonia	Personal communication with J. Polo at International Fertilizer Development Center (IFDC)
Cement	-	-	CO_2 emissions already estimated in NatCarb database [4]
Ethanol	-	-	CO_2 emissions already estimated in NatCarb database
Gas Processing	608	tCO_2/mmcfd/yr	Based on 4% average inlet gas CO_2 concentration and 1% average outlet gas CO_2 concentration
Refineries	9.9[5]	tCO_2/Yr/BPD	ExxonMobil "Report on Energy Trends, Greenhouse Gas Emissions and Alternative Energy," 2004 - Calculated as the company-wide average refinery emission rate
Ethylene	2.43	kg CO_2/kg Ethylene	ECOFYS
Ethylene Oxide	0.51	kg CO_2/kg Ethylene Oxide	ECOFYS[6]
Iron and Steel	1.27 (integrated steelworks) [7] 0.14 (electric arc furnace (EAF))	Kg CO_2/kg Steel	ECOSYS

2.3 Summary of Fossil Power Plants

The database used USEPA eGRID2007 data for power plant capacities, locations, operating factors, and CO_2 emission rates. The database only contains fossil power plants that are fired by coal, oil, or gas. The CO_2 emissions for these power plants were directly reported in the eGRID data and no emission factors were used to calculate total emissions.

The USEPA eGRID2007 database is the best available database of power plant emissions information. The database is updated and re-released on a periodic basis. The analyses within this section are based on the most recent version of the database available which was released in

[3] ECOSYS reported the emission factor for an ammonia steam reforming plant is 1.2 kg per kg ammonia produced.

[4] NATCARB estimated the emission factors of 0.89 -1.24 kg CO_2 /kg Clinker for the wet process based on different energy uses, 0.85 -1.15 kg CO_2 /kg Clinker for the dry process.

[5] ECOSYS reported an emission factor of 0.22 kg CO_2 per kg output based on the fuel mix in a UK refinery, which is equivalent to 12.2 tCO_2/Yr/BPD.

[6] A selectivity of 0.80 kg EO per kg ethylene is assumed.

[7] ECOSYS reported a range of 1.14 -14.40 kg CO_2/kg steel from integrated steelworks, with a mean value of 1.27.

November 2008 and revised in February 2009. It contains updated data for the year 2005. Table 2-3 summarizes the fossil power plants for the year of 2005 and compares with the old database that used the data for the year of 2004 (eGRID2006 data).

Table 2-3 Power Generation Capacity and CO_2 Emissions by Fuel (Year of 2004 and 2005)

		eGRID2006 Database (Year 2004)	**eGRID2007 Database (Year 2005)**
Gas	**Number**	1406	1424
	Capacity (GW)	388	399
	CO_2 Emissions (Mt)	390	356
Oil	**Number**	704	751
	Capacity (GW)	65	64
	CO_2 Emissions (Mt)	77	76
Coal	**Number**	631	576
	Capacity (GW)	370	361
	CO_2 Emissions (Mt)	2147	2121

Figure 2-1 shows the geographical distribution and the CO_2 emissions for fossil power plants in the continental states.

Figure 2-1 Fossil-Fired Power Plants

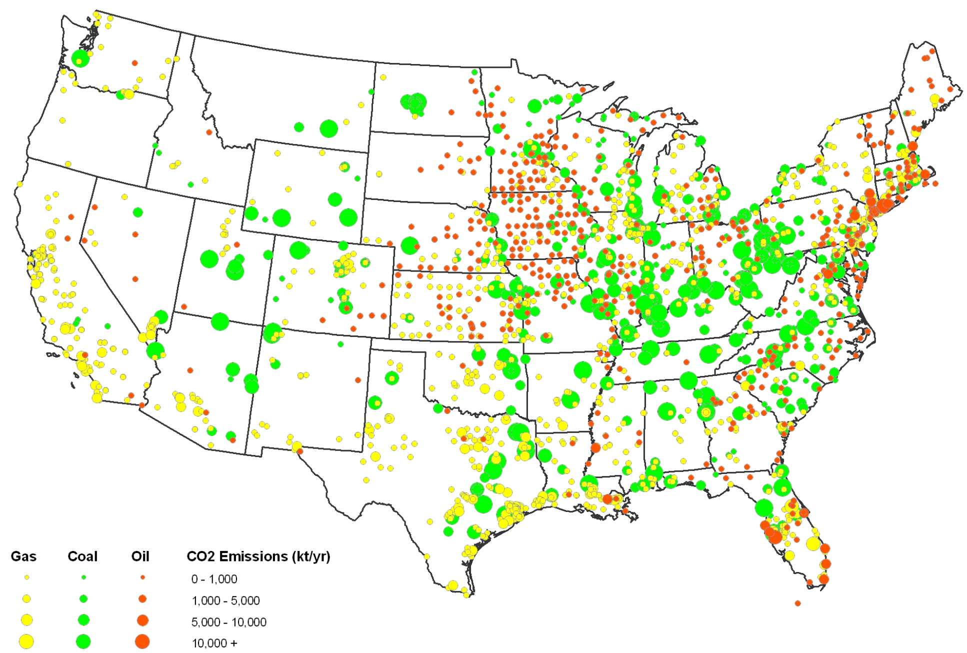
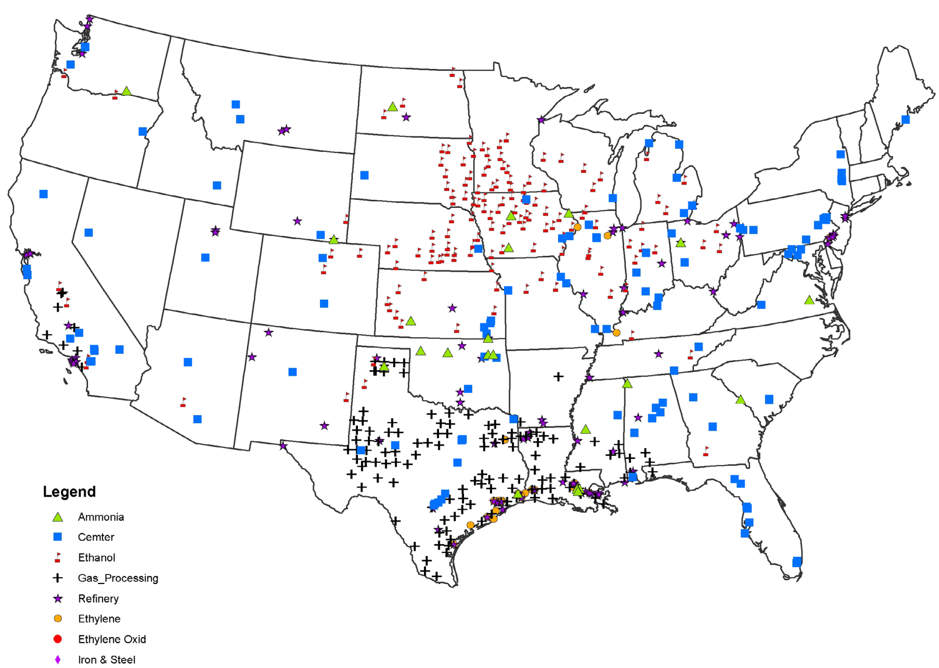


Figure 2-2: Non-Power Stationary CO_2 Sources



2.4 *Summary of Non-power Stationary CO_2 Sources*

The updated database also includes a variety of non-power stationary CO_2 sources. Figure 2-2 shows the geographical distribution of the non-power stationary CO_2 sources included in the database. The following of this section briefly summarizes each type of these non-power stationary CO_2 sources in the database and compares them with the old database.

2.4.1 Ammonia Plants

The ammonia plant database was updated with the latest available numbers from the *North America Fertilizer Capacity* by International Fertilizer Development Commission (IFDC). The most recent numbers were released in March 2009. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-4 compares the ammonia plant database with the old one that used the data for year of 2006.

Table 2-4 Ammonia Plant Comparison

	Current Database (Year of 2009)	Old Database (Year of 2006)
Number	29	34
Capacity (Mt/yr)	11	13
Estimated CO_2 Emissions (Mt/yr)	12	15

2.4.2 Cement Plants

The cement plant database was updated with new data set from NatCarb by the Kansas Geological Survey in 2006. Table 2-5 compares the cement plant database with old database that used the data for year of 2002. It is notable that although the total capacities remain almost the same, the estimated CO_2 emissions increase by one third. It is most likely that the change was caused by the difference in CO_2 emissions estimation methods[8].

Table 2-5 Cement Plant Comparison

	Current Database (Year of 2006)	Old Database (Year of 2002)
Number	117	100*
Capacity (Mt/yr)	87	86
Estimated CO_2 Emissions (Mt/yr)	97	64

* Only 29 plants have location information.

[8] The old database used an emission factor of 0.75 kg CO_2/kg Clinker for cement plants. However, the CO_2 emissions data for cement plants in this updated database was already estimated by the Kansas Geological Survey. A much complicated method was used.

2.4.3 Ethanol Plants

The ethanol plant database was obtained from NatCarb by the Kansas Geological Survey in 2006. There was no ethanol plant data included in the old database. Table 2-6 summarizes the ethanol production facilities.

Table 2-6 Ethanol Plant Summary

	Current Database (Year of 2006)
Number	140
Capacity (mmgy)	7,652
Estimated CO_2 Emissions (Mt/yr)	43

2.4.4 Refineries

The online database by the Energy Information Agency (EIA) of the US Department of Energy (DOE) was used to update capacity estimates of refineries in 2008. The ECOFYS database was then used for plant locations, with the USGS GNIS used to verify and update the location of new facilities. Table 2-7 compares the refinery database with the old database that used the data for year of 2006.

Table 2-7 Refinery Comparison

	Current Database (Year of 2008)	Old Database (Year of 2006)
Number	145	141
Capacity (1000 barrels / stream day)	18,321	17,319
Estimated CO_2 Emissions (Mt/yr)	181	171

2.4.5 Gas Processing Facilities

The database for gas processing facilities used data from the 2006 Oil and Gas Journal Gas Processing survey. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-8 compares the database with the old database that used the data from 2003 Oil and Gas Journal Gas Processing survey. The estimated CO_2 emissions are calculated using the CO_2 emission factor given in Table 2-2.

Table 2-8 Gas Processing Facility Comparison

	Current Database (Year of 2006)	Old Database (Year of 2003)
Number	566*	635**
Capacity (MMCFD)	69,815	79,170
Estimated CO_2 Emissions (Mt/yr)	42	48

* Only 253 facilities have location information.
** Only 276 facilities have location information.

However, the CO_2 emission rate from gas processing facilities is highly dependent on the percentage of CO_2 in the gas being processed by each facility. In order to better estimate these emissions, the USGS organic geochemistry database has been obtained. This database contains the CO_2 concentrations of the gas wells in the study area. By revising the CO_2 emissions factors using the USGS organic geochemistry database, we are working to provide better CO_2 emissions estimates for the gas processing facilities.

2.4.6 Ethylene, Ethylene Oxide, and Iron and Steel Plants

The ethylene plant database was updated with the latest available information from the Oil & Gas Journal's *International Survey of Ethylene* (July 2008). This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database.

The ECOFYS database released in 2002 contained the detailed datasets for ethylene oxide, and iron and steel plants. ECOFYS got the ethylene oxide information from the ChemWeek (www.chemweek.com), and the iron and steel information from the 2001 *World Steelworks Survey*. The information from these sources was used in old database. At this time, we decided not to update it due to the relatively small amount of CO_2 emissions from these sources.

Table 2-9 summarizes the plant capacity and the estimated CO_2 emissions for these three types of non-power CO_2 sources.

Table 2-9 Summary of Iron and Steel, Ethylene and Ethylene Oxide Plants

	Iron and Steel	Ethylene	Ethylene Oxide
Number	130	41	13
Capacity (kt/yr)	120,138	28,793	4,085
Estimated CO_2 Emissions (Mt/yr)	83	70	2

3 Annex 3: Regulatory Data for CCS in United States

3.1 Introduction

This annex provides the basic documentation for the regulatory data for carbon capture and storage in the United States. It is based on Adam Smith's (2004) thesis "*Regulatory Issues Controlling Carbon Capture and Storage*". The data include the Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Program, state-level action on climate change, and several types of protected and restricted land use areas to evaluate the possibility and difficulty in siting the future CCS projects.

3.2 Data Access and Summary

The data are stored as ArcSDE features in the MIT LFEE Carbon Sequestration Management ArcSDE database server and can be accessed via ArcGIS. Here are the instructions to access the data:

1) Go to ***ArcGIS → ArcCatalog***
2) On the left window, find ***Database Connections***, double click **Add Spatial Database Connections,** the screen should be similar to the one in page 3.
3) Enter the following account information:

IP:	e40-hjh-server2.mit.edu
Service:	port: 5151
Database:	(leave black)
User Name:	DOE_REG
Password:	DOE_REG

Figure 3-1 shows the connection property and Table 3-1 summarizes the data in the server.

Figure 3-1 Data Access Connection Property

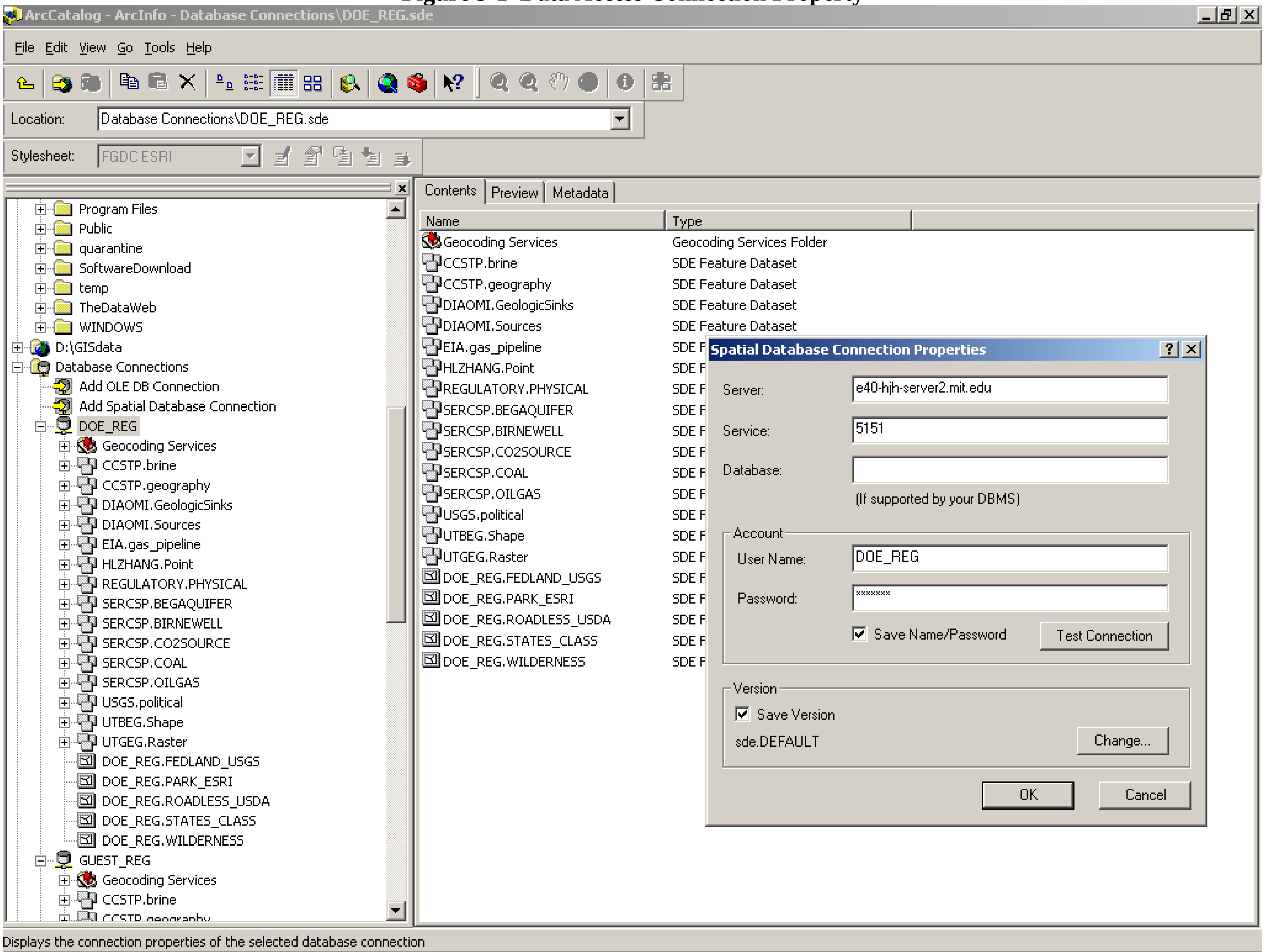


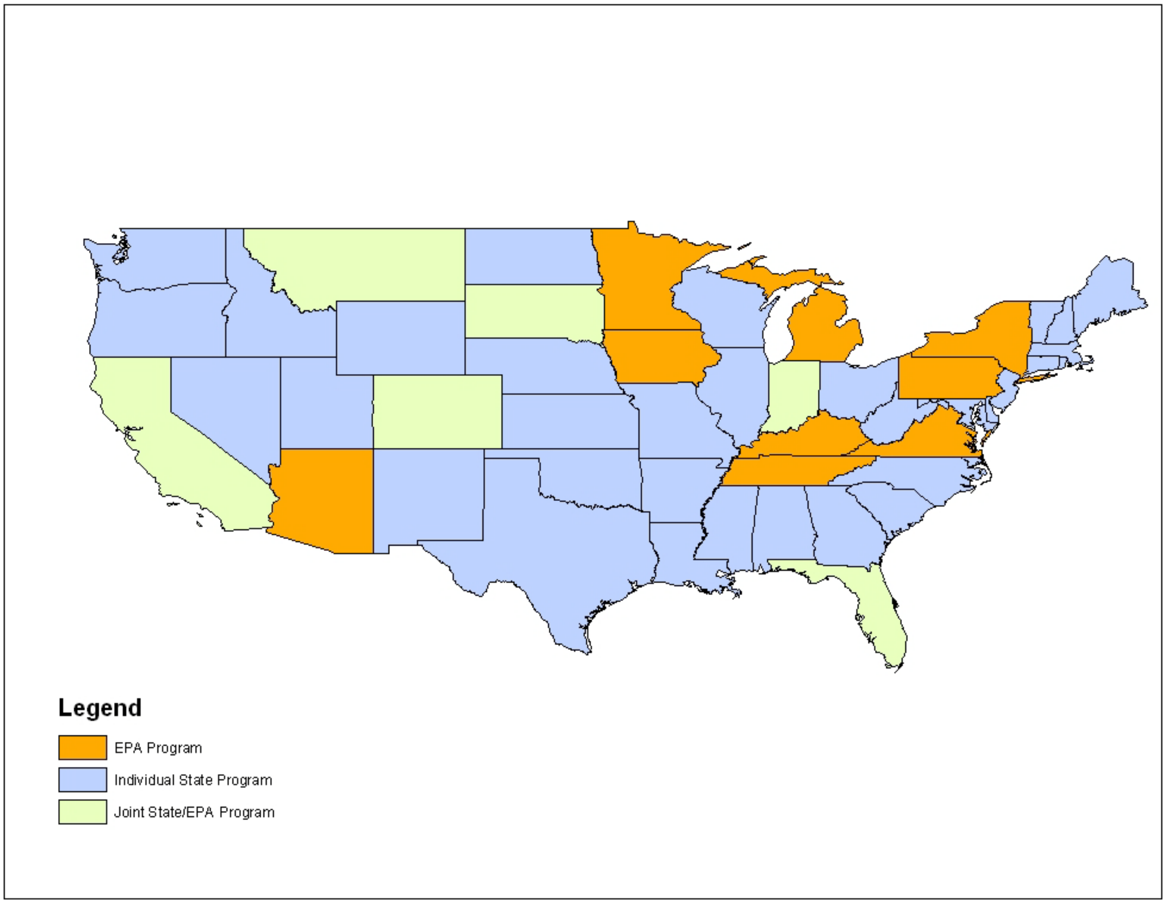
Table 3-1 Summary Table for Regulatory

SDE Features	Key Fields	Description	Coding
DOE_REG.PARKS_ESRI	FCC	Park Classification	D83-National Parks D85 Local Parks
DOE_REG.WILDERNESS	FEATURE	Wilderness Land Classification	Wilderness Non-wilderness
DOE_REG.FEDLAND_USGS	FEATURE1	63 types of federal-owned land	Details are available in the database
DOE_REG.ROADLESS_USDA	CATEGORY	Categories by Restrictions	1B: Inventoried Roadless Areas where road construction and reconstruction is prohibited 1B1: Inventoried Roadless Areas that are recommended for wilderness designation in the forest plan and where road construction and reconstruction is prohibited 1C: Inventoried Roadless Areas where road construction and reconstruction is not prohibited
DOE_REG.STATES_CLASS	UIC_REG	States Classified by Their Underground Injection Control Programs	Individual State Program Joint State/EPA Program EPA Program
	HW_WELL_CLS1	States Categories by Number of UIC Class I Hazardous Waste Wells	No HW Wells 1-10 HW Wells 11-20 HW Wells >70 HW Wells
	OG_WELL_CLS2	States Categories by Number of UIC Class II Oil & Gas Wells	No Known Wells 1-100 Wells 101-5,000 Wells 5,001-25,000 Wells >25,000 Wells
		State Categories on Climate Change Action	Class I: Most Proactive Class II Class III Class IV:Least Proactive

3.3 EPA Underground Injection Control (UIC) Program

The UIC program regulates the injection of wastes into the subsurface to protect current and potential sources of drinking water. States can apply to the EPA to run their own UIC programs if they meet basic proficiency criteria. Currently, 34 states run their own program, 6 share responsibilities with the EPA, and 10 are administered directly by the regional EPA office (see Figure 2).

Figure 3-2 Categories of States with UIC Primacy in the Continental United States



The UIC divides underground injection into five major classes. The nature of the waste and its disposal location determine what class an injection project will fall under (see Smith (2004) for details). EPA has statistics for the number of Class I and Class II wells at the state level and classifies states by the number of Class I and Class II wells, respectively. Figure 3-3 shows the distribution of Class I Hazardous wells in the United States. Class I wells are technologically sophisticated and inject hazardous and non-hazardous wastes below the lowermost underground source of drinking water (USDW).

Figure 3-3 UIC Class I Hazardous Waste Wells in the Continental United States

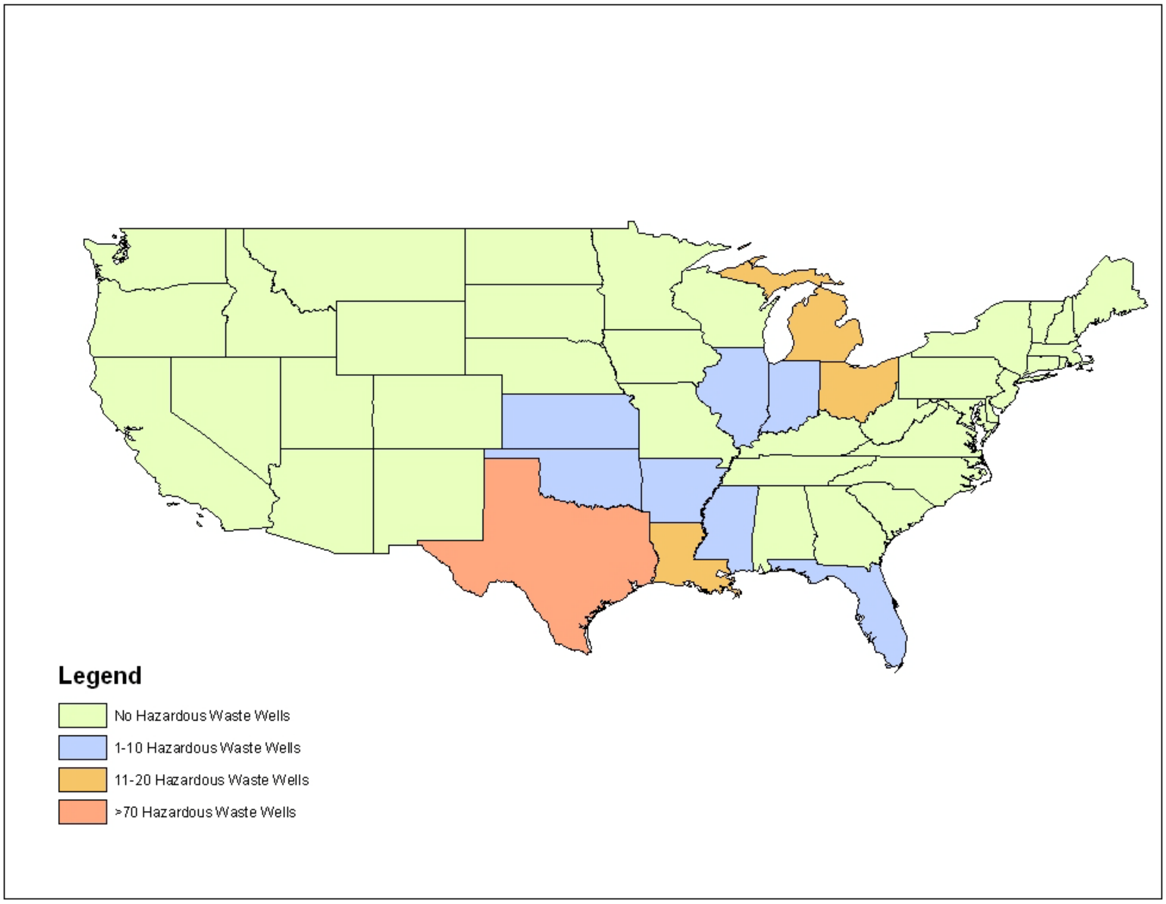
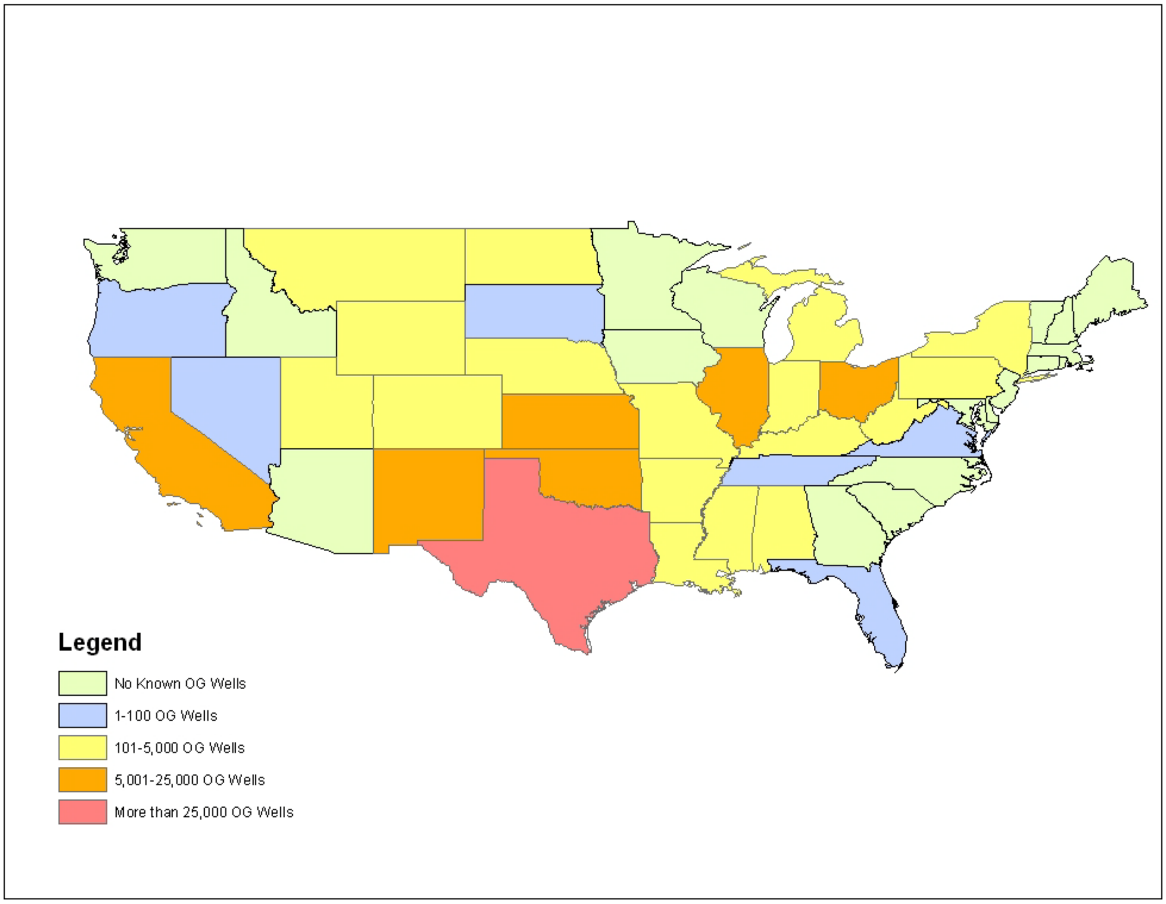


Figure 3-4 shows the distribution of UIC Class II Oil & Gas wells in the US. Class II wells are oil and gas production, brine disposal, and other related wells. Many Class II wells are enhanced oil recovery projects.

Figure 3-4 UIC Class II Oil & Gas Wells in the Continental United States

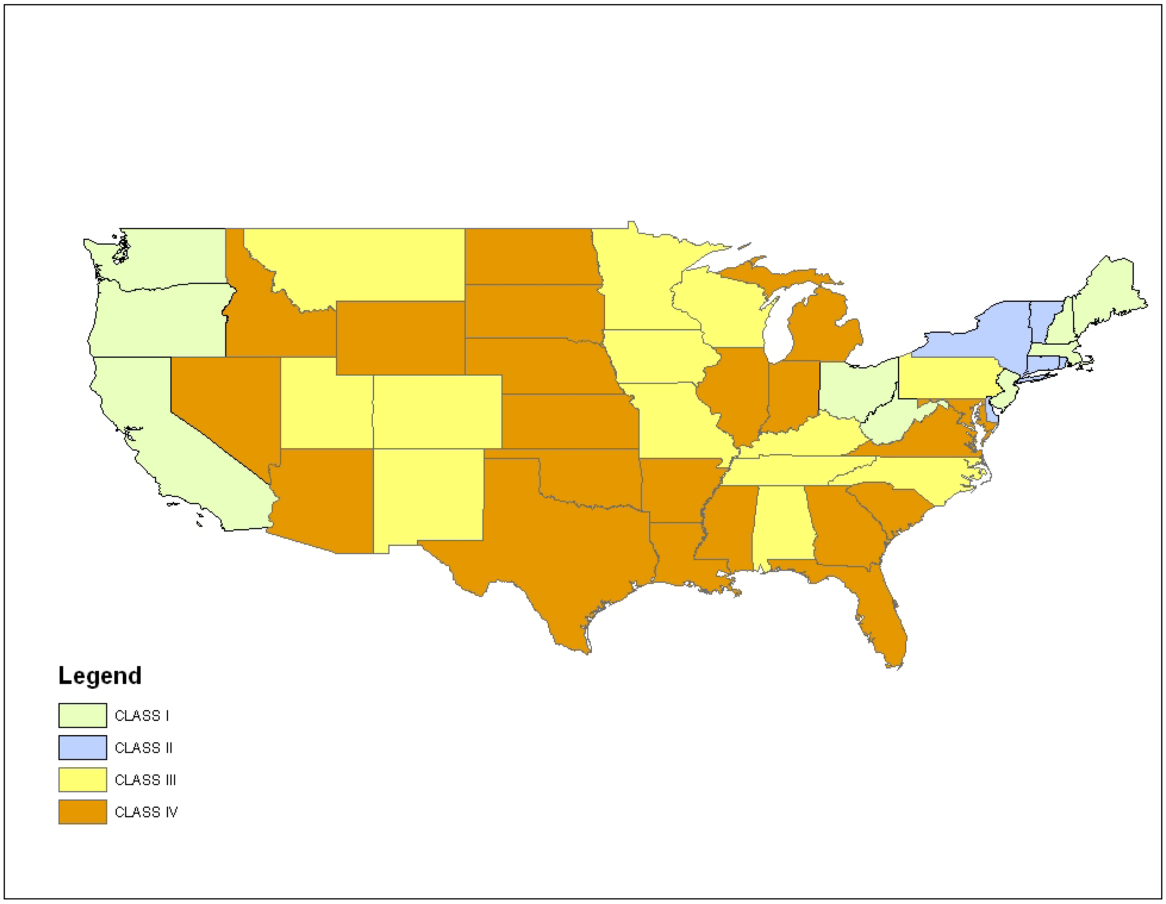


3.4 State Action on Climate Change

Adam Smith (2004) categorizes states by how proactive they are in addressing climate change (see Figure 3-5). States have been ranked as:

- Category I, states with legislation in place that controls greenhouse gas (GHG) emissions specifically;
- Category II, states in the process of planning controls on GHG emissions;
- Category III, states that have an action plan for greenhouse gas mitigation;
- Category IV, states that do not have, and are not actively planning to control GHG emissions nor do they have a greenhouse gas action plan.

Figure 3-5 State Categories on Climate Change Action in the Continental United States



3.5 Protected Areas

Carbon capture and storage projects in the future need to consider a combination of land ownership and regulation policies. Land use policies that constrain or forbid development projects are likely to affect the future of CCS projects. The regulatory data that we have incorporated so far into the GIS system include:

- National, state, and local park system (Figure 3-6);
- Inventoried roadless area (Figure 3-7);
- Wilderness area (Figure 3-8);
- Federal-owned lands (Figure 3-9).

Figure 3-6 National Parks and State and Local Parks in the Continental United States

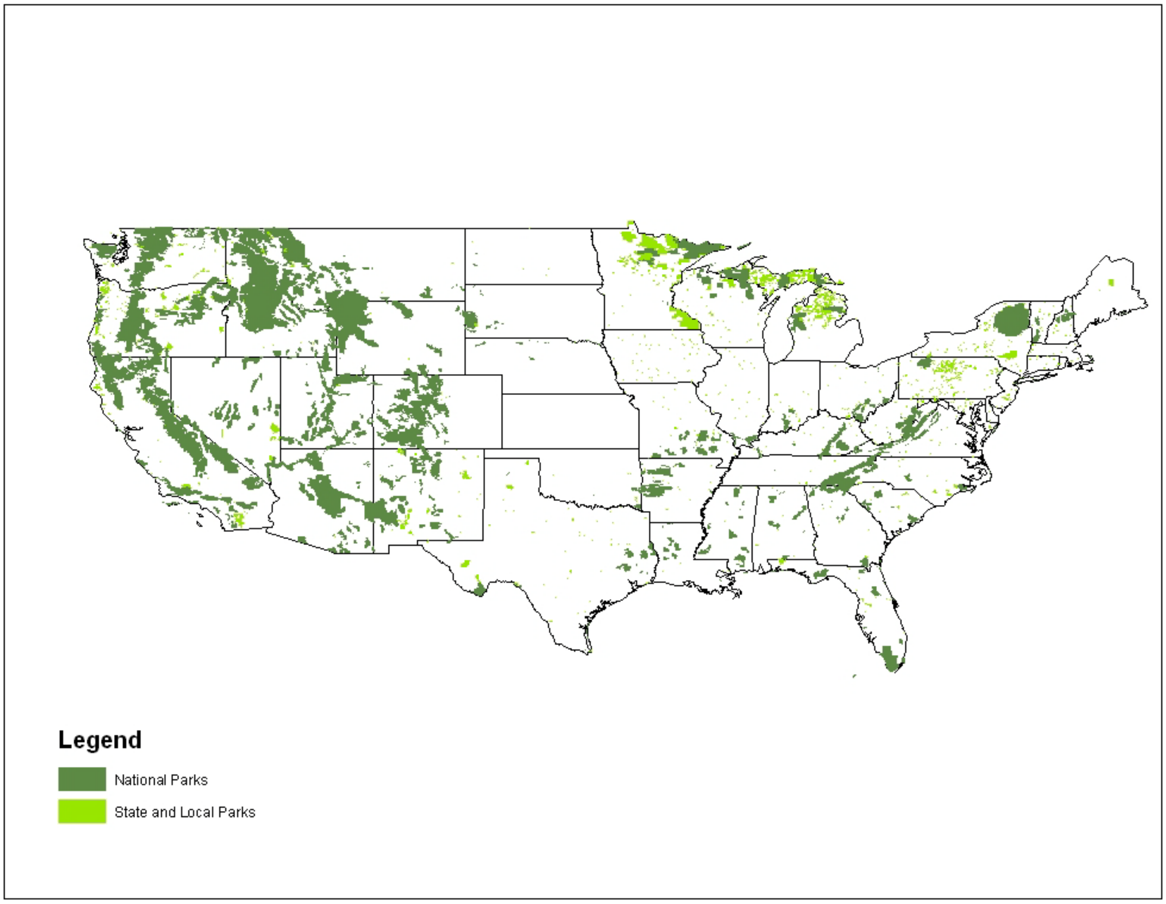


Figure 3-7 Inventoried Roadless Areas in the Continental United States

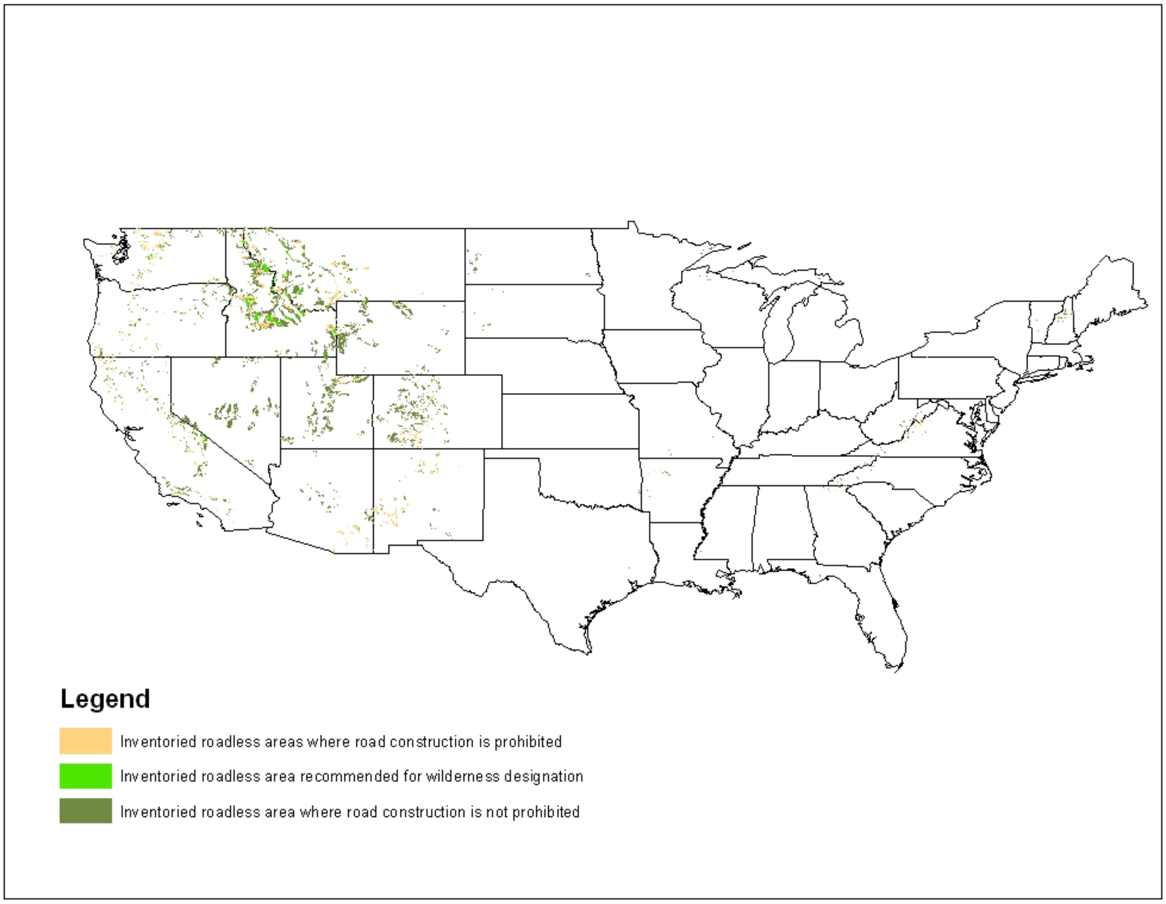


Figure 3-8 Wilderness Areas in the Continental United States

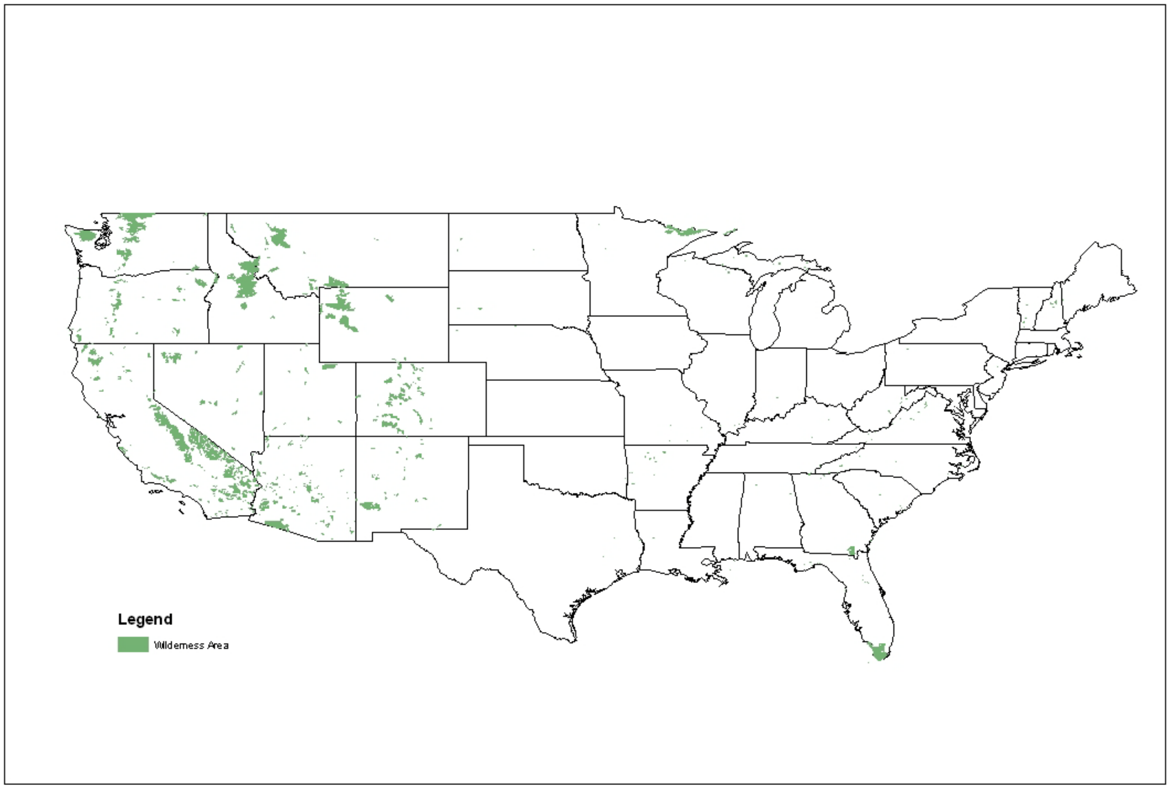
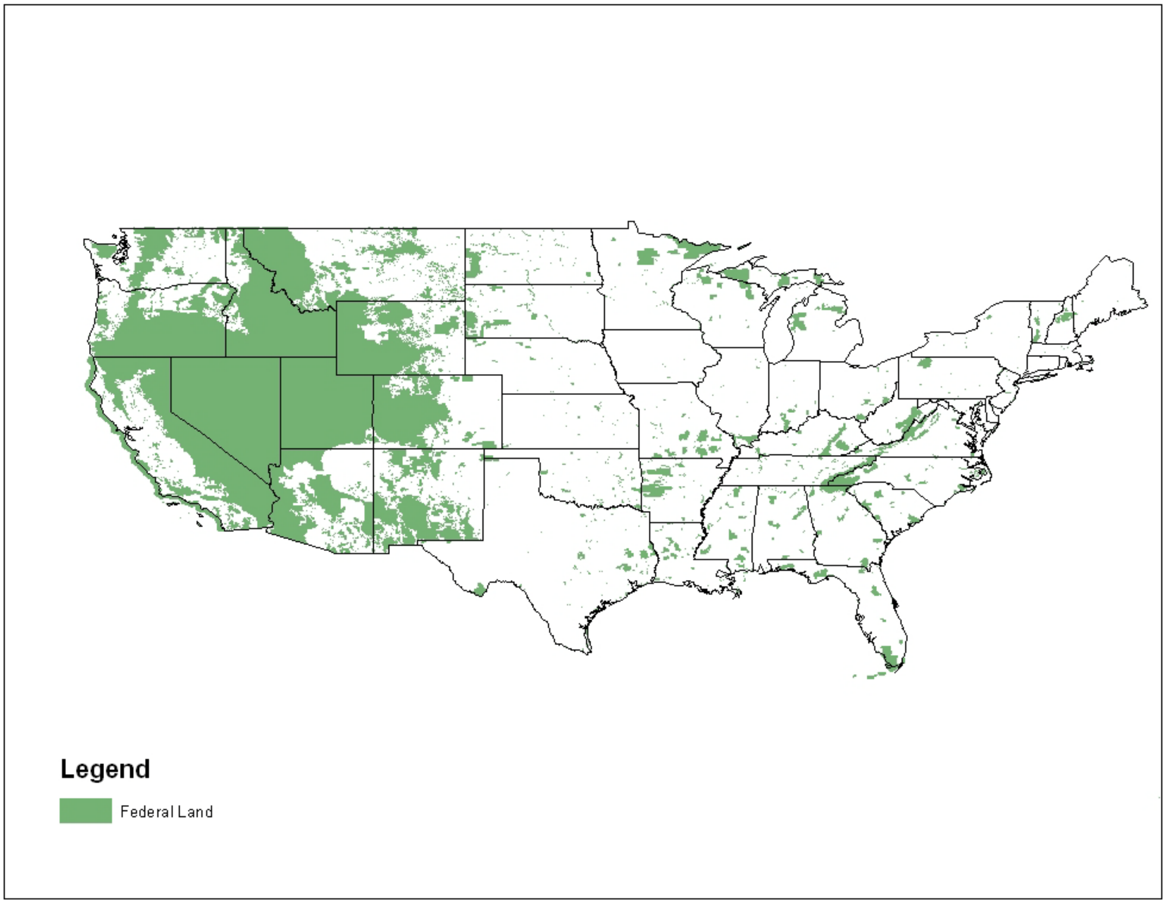


Figure 3-9 Federal Land in the Continental United States
(Database breaks down by 63 separate categories.)



References

Smith, Adam M. 2004. "Regulatory Issues Controlling Carbon Capture and Storage," *MIT Masters Thesis* (http://sequestration.mit.edu/pdf/Adam_Smith_thesis_June2004.pdf)

4 Annex 4: CO_2 Capture Cost Estimation

4.1 Introduction

This annex documents the CO_2 capture cost estimation tool.

In this annex:

- Section 4.2 presents the methodology used to calculate the CO_2 capture cost for stationary CO_2 sources. The study uses SFA Pacific capture cost tool as the basis to estimate the CO_2 capture cost in terms of both CO_2 captured and CO_2 avoided.
- Section 4.3 presents the estimated formula for CO_2 capture and avoidance costs as functions of power plant design capacity for coal-fired, gas-fired and oil-fired power plants.
- Section 4.4 presents the estimated formula for CO_2 capture and avoidance costs as functions of design capacity for four non-power CO_2 sources: ammonia plants, cement plants, gas processing facilities, and refineries.

4.2 Methodology

The study uses the "*Generic* CO_2 *Capture Retrofit*" spreadsheet prepared by *SFA Pacific, Inc*. as the basis for calculating the CO_2 capture cost for stationary CO_2 sources (see Figure 4-1). These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour); (2) the flue gas composition (volume share or weight share of CO_2 in flue gas); and (3) the annual load factor.

The SFA Pacific spreadsheet provides estimates of capture cost in terms of both CO_2 captured and CO_2 avoided. CO_2 captured is the amount of CO_2 captured by the absorber and kept out of the atmosphere; assumed to be 90% of the CO_2 in the flue gas except for ammonia and gas processing facilities, for which capture factor was assumed to be 100% as their flue gas only consists of pure CO_2. However, since the CO_2 capture process requires energy for purification and compression, the CO_2 avoided term subtracts the CO_2 emitted producing this process energy from the total amount of CO_2 captured. The two terms are used differently in CO_2 sequestration analysis. The CO_2 captured term is used for calculations involving the amount of CO_2 being handled, such as for pipeline transportation costs; while theCO_2 avoided term is used for calculations involving the amount of CO_2 withheld from the atmosphere and therefore eligible for possible CO_2 emissions credits.

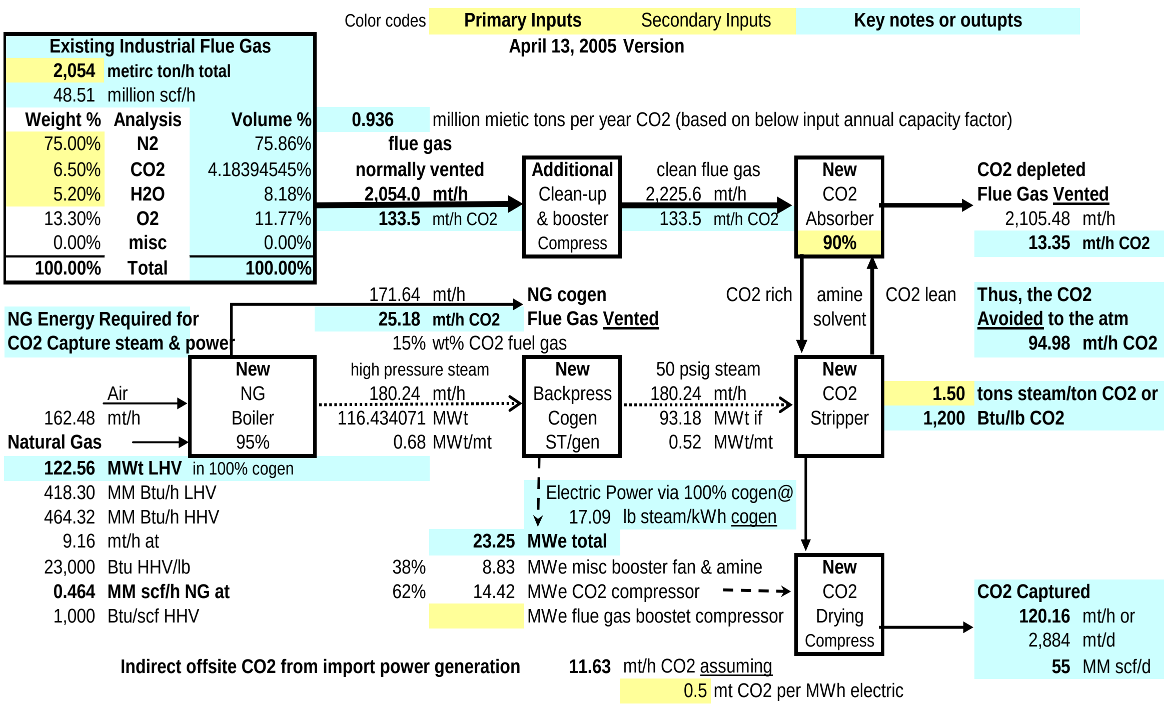
According to these two measurements, there are also two definitions on the per unit CO_2 capture cost. To avoid ambiguity, this section uses "CO_2 capture cost" to refer to the capture cost measured in per tonne CO_2 captured while "CO_2 avoidance cost" to refer to the capture cost measured in per tonne CO_2 avoided.

Figure 4-1 SFA Pacific CO_2 Capture Cost Tool

Generic Industrial CO2 Capture for Any Large CO2 Flue Gas Stream

April 2005 working draft by Dale Simbeck at SFA Pacific, Inc

Key assumption is that NG is use as the added energy source to make the steam & power required for CO2 capture
This avoides the loss of capacity or increased off-site CO2 emission of supplying additional electric power
Also the high demand of low pressure stripping steam for the amine CO2 stripper, favors a NG cogen boiler



		Unit cost basis at		cost/size	Actual unit cost at		millions of $	
Capital Costs		60	mt/h CO2	factors	120	mt/h CO2	2003 dollars	Notes
NG boiler	$	15	/lb/hr steam	75%	$13	/lb/hr steam	5.0	
cogen ST gen	$	500	/kWe	75%	$420	/kWe	9.8	
Additional cleanup	$	-	mt/h flue gas	75%	$0	mt/h flue gas	-	if SO2, NOx cleanup
Booster compressor	$	800	/kWe	75%	$672	/kWe	-	needed in many cases
CO2 absorber	$	25,000	mt/h flue gas	75%	$21,015	mt/h flue gas	46.8	
CO2 Stripper	$	200,000	mt/h CO2	75%	$168,124	mt/h CO2	20.2	
CO2 Compressor	$	1,000	/kW	75%	$841	/kW	12.1	
					Total process units		93.9	
General Facilities		20%	of process units				18.8	20-40% typical
Eng. Permitting & Startup		10%	of process units				9.4	10-20% typical
Contingencies		10%	of process units				9.4	10-20% typical
Working Capital, Land & Misc.		5%	of process units				4.7	5-10% typical
					U.S. Gulf Coast Capital Costs		136.1	
Site specific factor		110%	of US Gulf Coast		Total Capital Costs		149.7	CA costs are likely higher than Gulf Coast

					$/Mscf CO2	$/mt CO2 Cost		Notes
CO2 Costs		80%	ann load factor	MM $/yr	Capture	Capture	Avoided	high ann load is critical to cost
Variable Non-fuel O&M		1.0%	/yr of capital	1.5	0.09	1.78	2.25	0.5-1.5% typical
Natural Gas	$	5.00	/MM Btu HHV	16.3	1.02	19.32	24.44	$4- 7/MM Btu **industrial** rate
Carbon Tax	$	10.00	/ton Carbon	0.3	0.02	0.30	0.38	all electric power made onsite
Total Variable Operating Cost				18.0	1.13	21.40	27.08	
Fixed Operating Cost		5.0%	/yr of capital	7.5	0.47	8.89	11.25	4-7% typical for refining
Capital Charges		15%	/yr of capital	22.5	1.40	26.67	33.74	15-25% typical for private investment
			Total CO2 Costs	48.0	3.00	56.97	72.07	including return on investment

Note that the difference between capture and avoided CO2 costs is due to the energy required for CO2 capture steam & power

Source SFA Pacific, Inc. **April 13, 2005**

4.3 CO_2 Capture Cost for Fossil Fuel Power Plants

In order to use the SFA Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made *that power plants would operate at 80% of their designed capacity once the capture facility has been installed.* So for each fuel type the CO_2 capture cost only varies based on the plant's design capacity. The fossil power plants were grouped into three categories by fuel type: coal-fired, gas-fired, and oil-fired.[9] The study only analyzed power plants with a design capacity greater than 100MWe.

Two key input variables needed to estimate the CO_2 capture cost for the fossil fuel power plants are the flue gas flow rate and the flue gas composition. Since this specific information was unavailable for all of the power facilities, two further assumptions were used to derive reasonable values for these variables. The two flue gas assumptions were that: (*1) the flue gas flow increases linearly with the design capacity of a power plant; (2) within each fuel-type category, the flue gas composition is independent of the design capacity.* Table 4-1 provides the flue gas flow rate and composition used in the data for each type of fossil fuel power plant.

Table 4-1 Flue Gas Flow Rate and Composition for Coal-, Gas-, and Oil-Fired Power Plants

		Coal-fired PP	Gas-fired PP	Oil-fired PP[1]
Flow Rate (mt/h per 100MW design capacity)		4.06	5.14	4.6
Flue Gas Composition (% in Volume)				
	N_2	73.81%	75.86%	74.84%
	CO_2	15.15%	4.18%	9.67%
	H_2O	8.33%	8.18%	8.26%
	O_2	2.54%	11.77%	7.16%
	misc	0.16%	0.00%	0.08%

Note: [1]Data about oil-fired power plants are MIT Carbon Capture and Sequestration Technologies Program estimates. Others are from SFA, Pacific "*Generic CO2 Capture Retrofit* "and *"Existing Coal Power Plant CO2 Migration* "spreadsheets.

Using data derived from the SFA Pacific capture cost estimation tool, Figure 4-2 plots both the CO_2 capture cost and avoidance cost for coal-fired power plants as functions of the plant design capacity. The relationship between CO_2 capture and avoidance costs and the design capacity of the coal-fired power plant can be represented by the following two power functions (with R^2 close to 1):

$$yc = 78.57 * x^{-0.1168} \qquad (1)$$

$$ya = 99.40 * x^{-0.1168} \qquad (2)$$

[9] There are few power plants using BL (black liquid) or MWC (municipal waste solid) as primary fuels that have a design capacity slightly above 100 MWe. But the CO_2 emissions from those plants are substantially lower than plants using oil, gas, or coal as primary fuel. Therefore, the analysis is restricted to oil-, gas-, and coal-fueled power plants with design capacity of at least 100MWe.

where yc = cost per tonne of CO_2 captured ($/t)
ya = cost per tonne of CO_2 avoided ($/t)
x = design capacity of the coal-fired power plant (MWe)

Taking derivatives on both sides of Equation (1), the CO_2 capture/avoidance cost elasticity with respect to plant design capacity is $\frac{dy/y}{dx/x} = -0.1168$. In practical terms this means that due to economies of scale the per unit CO_2 capture/avoidance cost decreases by 0.1168 percent for every 1 percent increase in power plant design capacity.

Figure 4-3 and Figure 4-4 plot the relationship between the CO_2 capture and avoidance costs and plant design capacity for gas-fired and oil-fired power plants, respectively. Table 4-2 summarizes the estimated formula for CO_2 capture and avoidance costs as functions of power plant design capacity for each fuel type category.

Figure 4-2 Estimated CO_2 Capture and Avoidance Costs for Coal-fired Power Plants

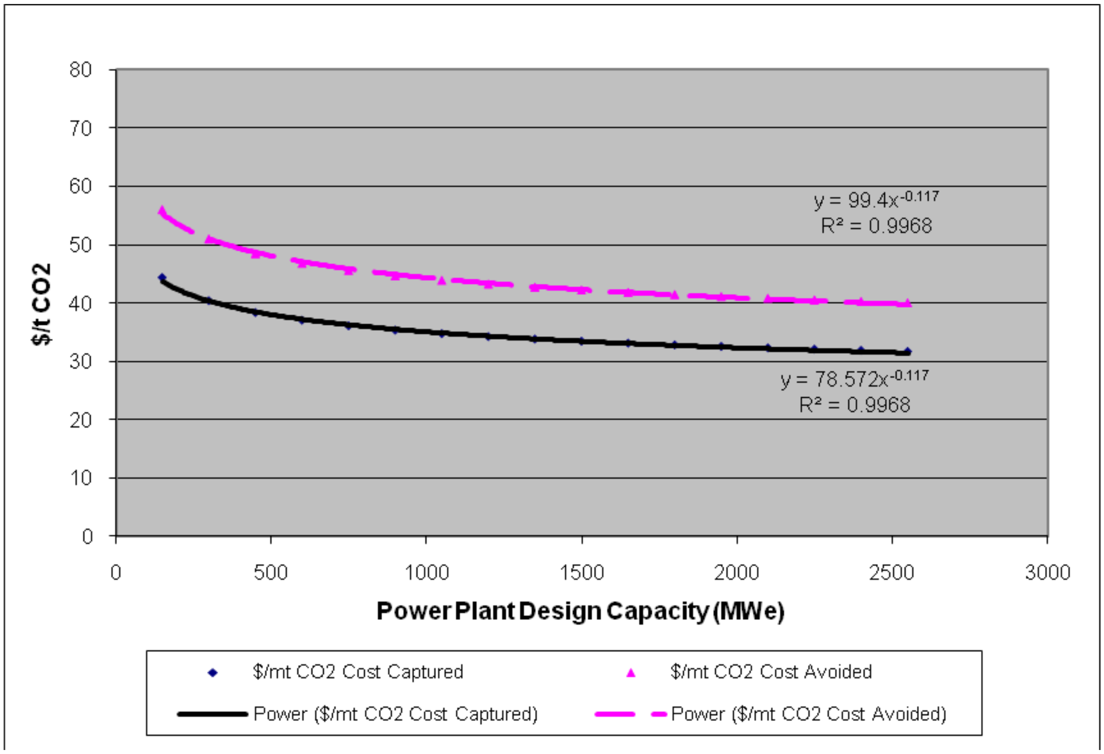


Figure 4-3 Estimated CO_2 Capture and Avoidance Costs for Gas-fired Power Plants

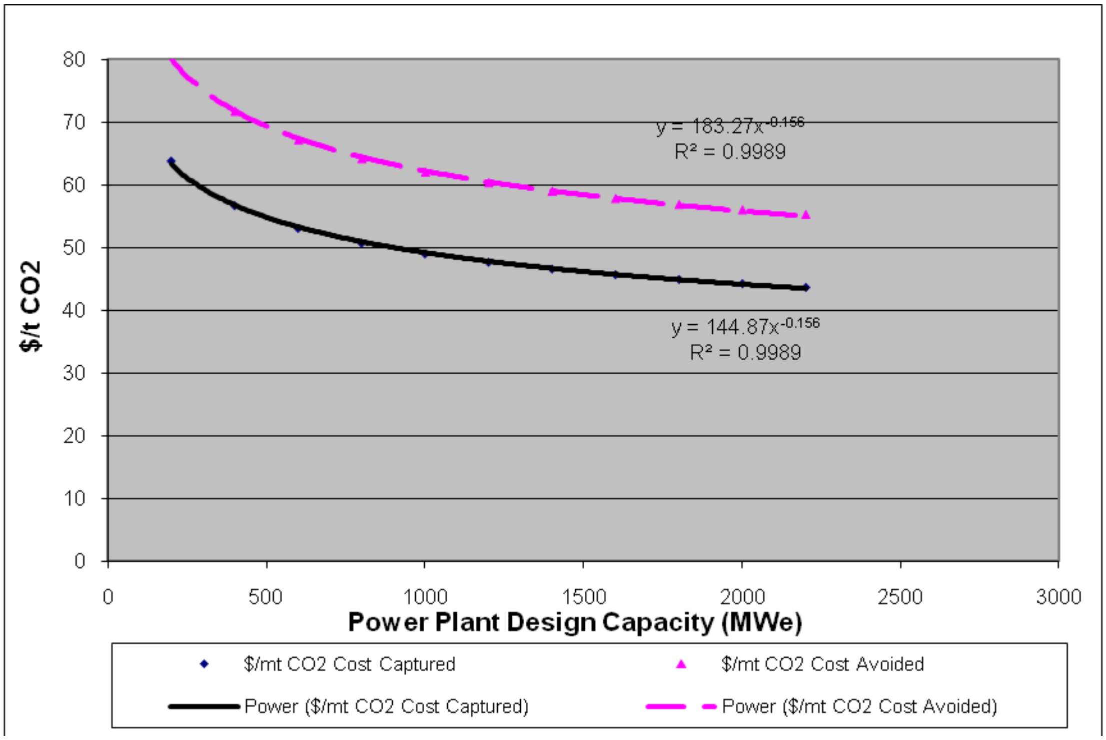


Figure 4-4 Estimated CO2 Capture and Avoidance Costs Oil-fired Power Plants

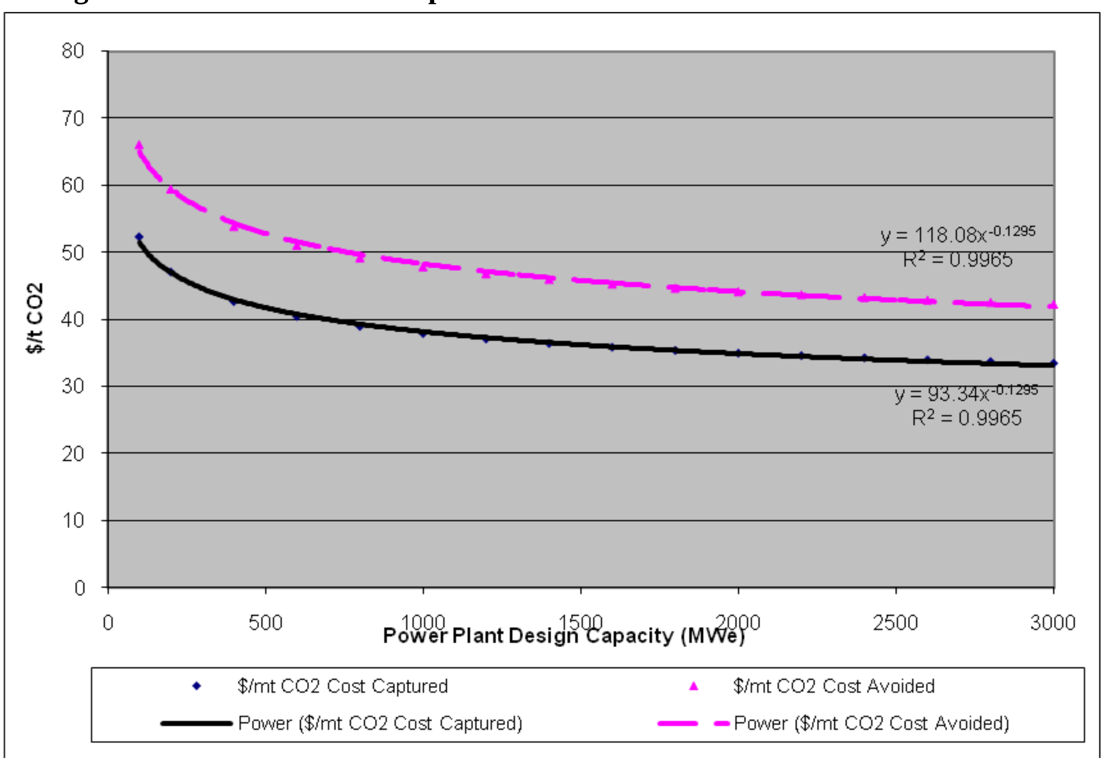


Table 4-2 Formula of per tonne CO2 Capture and Avoidance Cost for Power Plants

Category	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
$/t CO2 Captured Formula	$78.57x^{-0.1168}$	$144.87x^{-0.1564}$	$93.34\ x^{-0.1295}$
$/t CO2 Avoided Formula	$99.40x^{-0.1168}$	$183.27x^{-0.1564}$	$118.08x^{-0.1295}$

Note: x is the power plant design capacity in MWe.

4.4 CO_2 Capture Cost for Non-power Stationary Sources

The capture cost estimation tool from SFA Pacific, Inc. was adapted so that it could be used with the non-power sources in the SECARB region. As discussed, three key variables were needed for the estimation: (1) the flue gas flow rate; (2) the flue gas composition; and (3) the annual load factor. The flue gas composition information was only available for the following four facility types: ammonia plants, cement plants, gas processing facilities, and refineries. As a result the analysis was limited to estimating the capture cost for the four facility types listed.

Table 4-3 Assumed CO2 Emission Factor, Flue Gas Component and Load Factor for Non-power CO2 Sources

Facility Type	CO2 Emission Factor	Flue Gas Component (volume)	Annual Load Factor
Ammonia	1.13t CO_2/t Ammonia	100% CO_2	100%
Cement	0.75t CO_2/t Clinker	25% CO_2, 75%N_2	100%
Gas Processing	608t CO_2/mmcfd	100% CO_2	100%
Refineries	9.9t CO_2/BPD	10% CO_2, 90% N_2	100%

Table 4-3 lists the assumed CO_2 emission rates per unit of primary product production, the flue gas composition, and the annual load factor used for each of the four types of non-power CO_2 sources evaluated. The actual flue gas flow rates were unknown, but they were estimated based on plant capacity, the CO_2 emissions factor, and the flue gas composition.

Using these assumptions with the generic SFA CO_2 capture model, Figure 4-5 through Figure 4-8 plot the per unit CO_2 capture cost and avoidance cost as power functions of facility capacity for each type.

Figure 4-5 Estimated CO_2 Capture and Avoidance Costs for Ammonia Plants

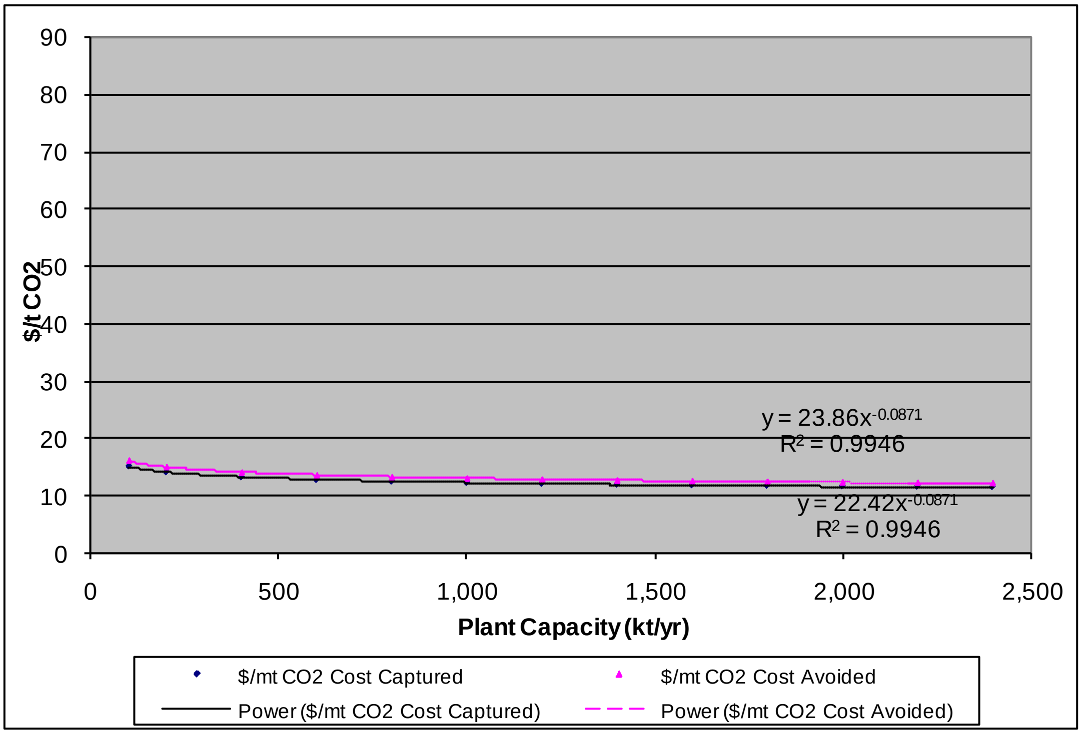


Figure 4-6 Estimated CO_2 Capture and Avoidance Costs for Cement Plants

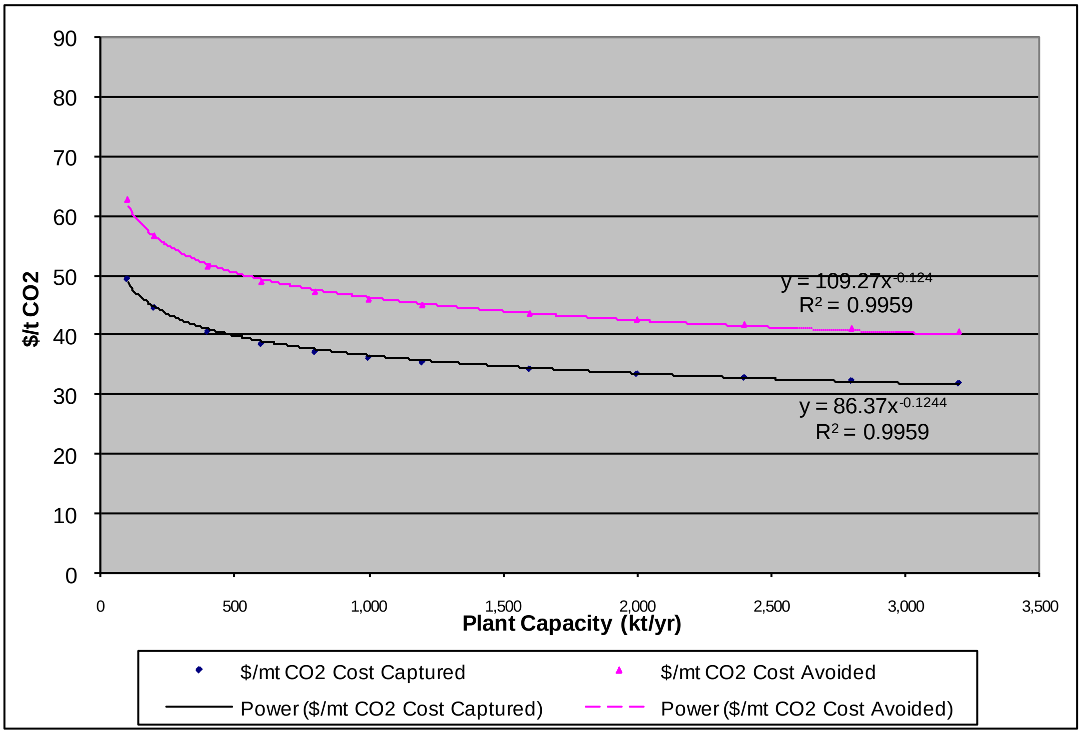


Figure 4-7 Estimated CO_2 Capture and Avoidance Costs for Gas Processing Plants

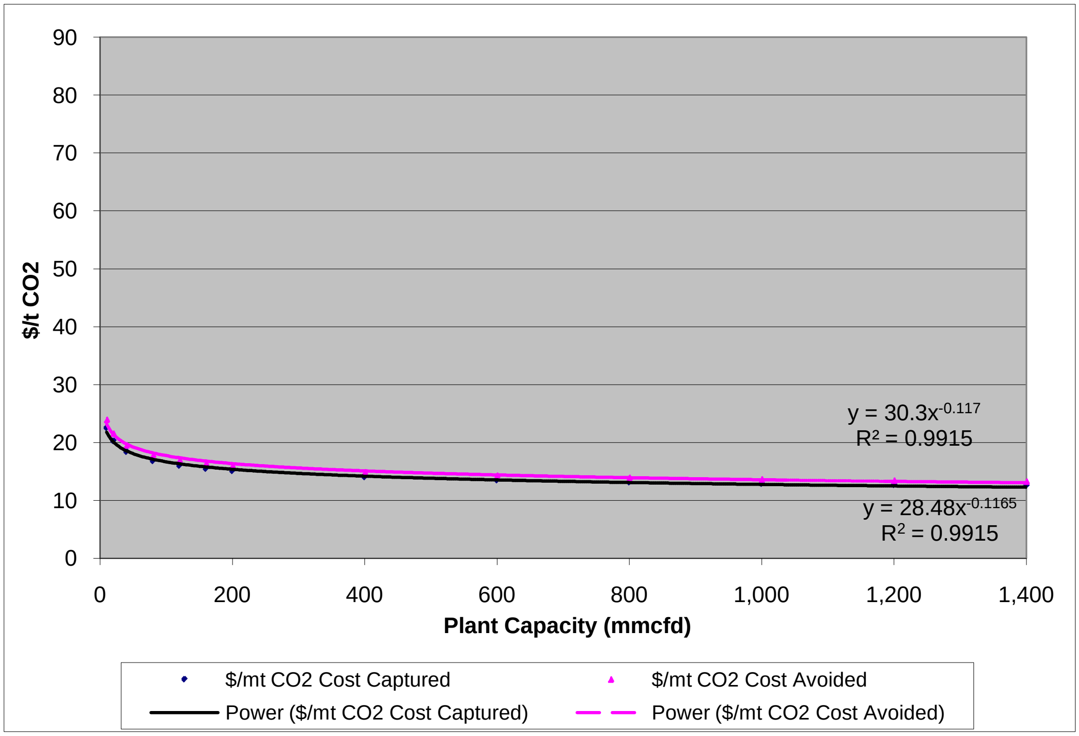


Figure 4-8 Estimated CO_2 Capture and Avoidance Costs for Refineries

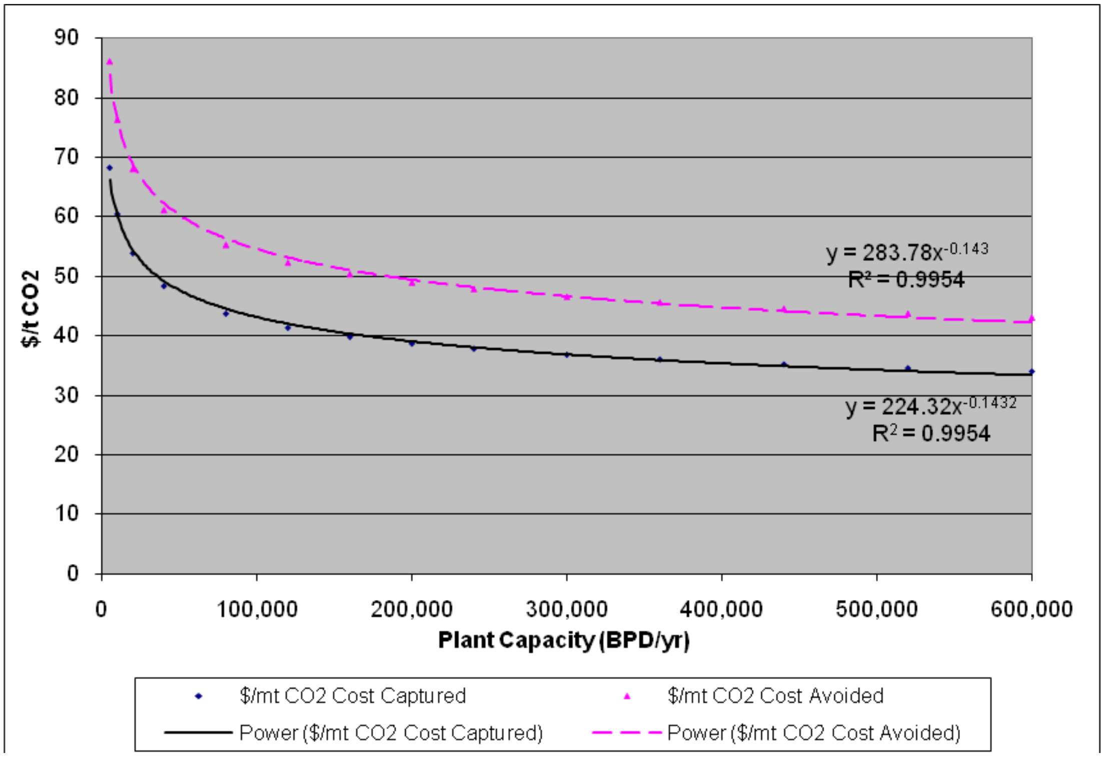


Table 4-4 summarizes the estimated formula for CO_2 capture and avoidance costs as functions of design capacity for the four non-power CO_2 sources. Since both ammonia and gas processing facilities produce pure CO_2 byproduct streams, CO_2 capture at these facilities only requires gas compression but not gas separation. As a result the CO_2 capture cost at these facilities is less than at either cement or refinery facilities.

Table 4-4 Formula of per tonne CO2 Capture and Avoidance Cost for Four Non-Power Sources

Category	**Ammonia**	**Cement**	**Gas Processing**	**Refineries**
Capacity Unit	kt/yr	kt/yr	MMCFD	BPD/yr
$/t CO2 Captured Formula	$22.425x^{-0.0871}$	$86.37x^{-0.1244}$	$28.48x^{-0.1165}$	$224.32x^{-0.1432}$
$/t CO2 avoided Formula	$23.856x^{-0.0871}$	$109.27x^{-0.1244}$	$30.3x^{-0.1165}$	$283.78x^{-0.1432}$

Note: x is the design capacity expressed by the unit listed.

References

Simbeck, D. 2005. *Generic Industrial CO_2 Capture for Any Large CO_2 Flue Gas Stream*.

5 Annex 5: CO_2 Storage Capacity Tools Documentation

5.1 Introduction

This annex documents the CO_2 storage capacity estimation tools developed. In the Carbon Management GIS project, we have developed standardized capacity tools to estimate the CO_2 storage capacity for each of the following three types of geological CO_2 storage sinks:

- Hydrocarbon (oil & gas) reservoirs (Section 5.2)
- Saline aquifers (Section 5.3)
- Coalbeds (Section 5.4)

We have spent further efforts to build the ArcGIS models for the hydrocarbon reservoirs and saline aquifers capacity tools and integrated them into the ArcGIS system.

5.2 CO_2 Storage in Hydrocarbon Reservoirs

5.2.1 CO_2 Storage Capacity of Hydrocarbon Reservoirs

A significant amount of pore space is vacated in underground hydrocarbon reservoirs when hydrocarbons are produced from the reservoir. CO_2 can be stored in the pore space left vacant by the hydrocarbon production. The CO_2 storage capacity of each reservoir depends on the amount of hydrocarbon fuel produced from the reservoir, with the total expected future storage capacity dependant on the total expected hydrocarbon production. In order to estimate storage capacity an assumption was made in this study that the entire underground volume of the hydrocarbons produced from a reservoir can be replaced by CO_2. Therefore, the future CO_2 storage capacity of a hydrocarbon reservoir can be calculated from ***the underground volume of the ultimately recoverable oil and gas***.

Not every hydrocarbon reservoir is suitable for CO_2 storage, and reservoirs were only analyzed for CO_2 storage if the initial pressure and temperature were above the critical point of CO_2. If the pressure and temperature of the reservoir were unknown, the reservoirs were only analyzed if they were at a depth of 3,000 feet or greater. The generalized theoretical formula adopted in estimating the CO_2 storage capacity of a hydrocarbon field with depth over 3,000 feet can be expressed as:

$$Q_{CO2} = (V_{Uoil} + V_{Ugas}) * \rho_{CO_2} \tag{1}$$

where Q_{CO2} = CO_2 storage capacity (Mt CO_2)
V_{Uoil} = underground volume of the ultimately recoverable oil (km^3)
V_{Ugas} = underground volume of the ultimately recoverable gas (km^3)
ρ_{CO_2} = CO_2 density at the reservoir conditions (kg/m^3)

The CO_2 density at the reservoir conditions was calculated using correlations from V. V. Altunin (1975) that assumes the CO_2 density is a function of the pressure and temperature of the reservoir[10].

The underground volumes of oil and gas in equation (1) are calculated from the standard volumes of oil and gas based on the following conversion formula:

$$V_{Uoil} = V_{oil(st)} * B_o \tag{2}$$

$$V_{Ugas} = V_{gas(st)} * B_g \tag{3}$$

where $V_{oil(st)}$ = volume of oil at standard conditions (km^3)
$V_{gas(st)}$= volume of gas at standard conditions (km^3)
B_o = oil formation volume factor
B_g = gas formation volume factor

In this study, a default B_o of 1.2 is applied for oil. B_g is estimated using the following equation:

$$\mathrm{B_g} = (4.8\,\mathrm{P} + 93.1)^{-1} \tag{4}$$

where P = the reservoir pressure (MPa).

Data on the underground volume of the ultimately recoverable oil and gas in a field is generally not available, so equation (1) usually cannot be directly applied to estimate the CO_2 storage capacity of hydrocarbon fields. But in cases information on the amount of original oil in place (OOIP) or original gas in place (OGIP) is known, the ultimately recoverable oil or gas can be estimated as a proportion of OOIP or OGIP.

$$V_{Uoil} = V_{OOIP} * p_{oil} \tag{5}$$

$$V_{Ugas} = V_{OGIP} * p_{gas} \tag{6}$$

where V_{OOIP} = underground volume of original oil in place (km^3)
V_{OGIP} = underground volume of original gas in place (km^3)
$p_{oil/gas}$ = volume percentage of OOIP/OGIP that are recoverable (%)

According to the JOULE II report, the average underground volumes of the ultimately recoverable oil and gas are approximately 35% of OOIP and 80-90% of OGIP, respectively. Therefore, when OOIP and OGIP information is available, equation (1), together with equations (5) and (6) give the formula to estimate the CO_2 storage capacity in hydrocarbon fields.

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[10] The CO_2 density was calculated using a computer code developed by Victor Malkovsky of the Institute of Geology of Ore Deposits, Petrography, Mineralogy and Geochemistry (IGEM) of the Russian Academy of Sciences, Moscow. We converted his FORTRAN code into Visual Basic.

5.2.2 The Adopted "Conservative" Approach

In most cases, information on the OOIP and OGIP for a reservoir is unavailable. The best data that is available is the cumulative oil and gas production up to the date when the data was collected. To make use of this data, the cumulative production of oil and gas was used to replace the ultimately recoverable oil and gas in equation (1). This methodology will result in an underestimation of the CO_2 storage capacity, particularly for fields that are in early stages of production. However, this approach provides the ability to calculate consistent estimates of the CO_2 storage capacity for most of the oil and gas fields using available data. Using this methodology, equation (1) can be rewritten as:

$$\tilde{Q}_{CO2} = (\tilde{V}_{Uoil} + \tilde{V}_{Ugas}) * \rho_{CO_2} \tag{7}$$

where $\tilde{Q}_{CO2}$ = CO_2 storage capacity (Mt CO_2)

$\tilde{V}_{Uoil}$ = underground volume of the cumulative oil production (km^3)

$\tilde{V}_{Ugas}$ = underground volume of the cumulative gas production (km^3)

Equation (7) was then used as the baseline formula in estimating the CO_2 storage capacity for hydrocarbon reservoirs.

5.2.3 Categorizing the CO_2 Storage Potential for Hydrocarbon Reservoirs

Oil and gas reservoirs were classified into different types in terms of their depths and API gravities. Reservoirs that are at least 3000 feet[11] deep are under enough pressure for supercritical CO_2 injection, so this depth is used as an initial criterion for determining whether hydrocarbon fields have CO_2 storage potential. The API gravity, a measurement of oil density which indicates CO_2 miscibility, is used to determine the EOR potential for oil fields. Oil fields with API gravity more than 25^o are classified as fields with miscible CO_2-EOR potential. Oil fields with API gravity between 17.5^o and 25^o are classified as fields with immiscible CO_2-EOR potential. Based on these criteria, the oil fields can be divided into five categories:

(1) Fields with miscible CO_2-EOR potential (depth > 3000 feet, API>25)
(2) Fields with immiscible CO_2-EOR potential (depth > 3000 feet, 17.5<API<25)
(3) Fields with CO_2 storage potential but no EOR potential (depth > 3000 feet, API<17.5)
(4) Fields without CO_2 storage potential (depth < 3000 feet)
(5) Undetermined Fields (depth or API missing)

The gas fields are classified into three categories based on the depth information:

(6) Fields with CO_2 storage potential (depth > 3000 feet)
(7) Fields without CO_2 storage potential (depth < 3000 feet)
(8) Undetermined Fields (Unknown depth)

[11] 3,000 feet (approx. 914 m) is chosen as a conservative depth threshold. Some studies suggest using 800 m as depth threshold. The result does not differ much from using 800 m as the depth threshold as few fields have depth between 800 m and 914 m.

5.3 CO_2 Storage in Saline Aquifers

Deep saline aquifers have the greatest CO_2 sequestration potential since they are the most common and most voluminous type of reservoirs. Two preliminary screening criteria are used to evaluate the CO_2 storage suitability of saline aquifers. The first screening criterion is similar to hydrocarbon reservoirs that the depth of the aquifer needs to be more than 800 m to ensure that the injected CO_2 can be kept at the supercritical phase. Second, the aquifer needs to have good seal properties so that the injected CO_2 can be sufficiently trapped in the aquifer.

If the above two screening criteria are satisfied, the CO_2 storage capacity of a saline aquifer can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO_2} \tag{8}$$

where Q_{aqui} = storage capacity of entire aquifer (Mt CO_2)
V_{aqui} = total volume of entire aquifer (km^3)
p = reservoir porosity (%)
e = CO_2 storage efficiency (%)
ρ_{CO_2} = CO_2 density at reservoir conditions (kg/m^3)

If accurate spatial data are available for an aquifer, then the aquifer volume used in equation (8) can be calculated as an integral of the surface area and the thickness of the aquifer:

$$V_{aqui} = \sum_i S_i T_i \tag{9}$$

where S_i is the area of the raster cell,
T_i is the thickness of the cell,

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For the "closed" aquifer, the storage efficiency is estimated as 2% (Holloway, 1996).

5.4 CO_2 Storage in Coalbeds

The CO_2 storage capacity of coalbeds used for CO_2-Enhanced Coalbed Methane Recovery (ECBMR) operations can be estimated using a methodology based on work by Scott R. Reeves (2003). The original methodology developed by Reeves is useful for estimates of storage capacity at the basin level. In this study Reeve's methodology was adapted for use with data collected at the coalfield level.

The principle idea of the CO_2 disposal in coalbeds is that CO_2 can be adsorbed more readily onto the coal matrix than methane. Therefore, the CO_2-ECBMR operation involves absorbing the injected CO_2 at the expense of methane. The displaced methane can be recovered as a free gas at production wells.

The CO_2 storage potential of a Coalbed results from the two primary mechanisms listed below:

- Storage capacity via methane replacement
  In this process, the primary methane production is assumed to create a voidage in the coal reservoir, which can be replaced by CO_2 up to the original pressure of the coal reservoir.

- Incremental storage capacity via ECBMR
  The secondary methane production through CO_2 injection produces additional methane which enables some additional CO_2 storage capacity.

Coalfields are categorized as either "commercial" or "non-commercial" according to the economic feasibility of producing methane from the field. "Non-commercial" areas are areas where ECBMR and CO_2 storage is technically feasible, yet unprofitable. "Commercial" coalfields are those where ECBMR operations are both technically and financially feasible. "Non-commercial" areas are usually deeper, have thinner coals, and are less permeable than the "commercial" areas. The storage capacity of "commercial" coalfields results from both primary and incremental methane replacement, whereas the capacity of "non-commercial" coalfields is from incremental methane replacement. Accordingly, different parameters are used to calculate the storage capacity of the two types of fields via ECBMR. Section 5.4.1 and Section 5.4.2 discuss details of the methodology for estimating the CO_2 storage capacity for "commercial" methane fields and "non-commercial" methane fields, respectively.

5.4.1 CO_2 Storage in "Commercial" Methane Fields

5.4.1.1 Storage Capacity via Methane Replacement

CO_2 storage capacity available due to methane displacement can be estimated using a coal-rank based ratio that specifies the ratio of the volume of CO_2 that can be injected per volume of CH_4 produced and the primary recovery factor of methane. Due to concerns about reservoir over-pressurization or the ability to gain adequate reservoir access a Voidage Replacement Efficiency Factor (*e*) is used to reflect the percentage of void space occupied by CO_2.

$$Q_{replacement} = r * e * V_{OGIP} * PRF * \rho_{CO_2} \tag{10}$$

where $Q_{replacement}$ = CO_2 storage capacity via methane replacement
r = CO_2/CH_4 ratio
e = Voidage replacement efficiency
V_{OGIP} = original gas in place (volume in standard condition)
PRF = primary recovery factor of methane (%)
ρ_{CO_2} = CO_2 density (in standard condition)

According to Reeves (2003), the baseline value of e is 0.75 and the baseline value of PRF is 65%. Column (2) of Table 5-1 gives the CO_2/CH_4 ratio based on the coal rank.

5.4.1.2 Incremental Storage Capacity via ECBMR

Additional CO_2 storage capacity due to the incremental methane production is estimated using a coal-rank based ratio and the ECBMR recovery factor (expressed as a percentage of in-place resource at the start of CO_2 injection).

$$Q_{ECBM} = r * e * V_{OGIP} * (1 - PRF) * ERF * \rho_{CO_2} \qquad (11)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery
r = CO_2/CH_4 ratio
e = Voidage replacement and ECBMR efficiency factor
V_{OGIP} = original gas in place (volume in standard condition)
PRF = primary recovery factor
ERF = ECBM recovery factor
ρ_{CO_2} = CO_2 density (in standard condition)

The baseline values for e and PRF are 0.75 and 65%, respectively while the ERF depends on the coal rank. Column (3) of Table 5-1 gives the ECBM recovery factor for each type of coal rank.

5.4.1.3 Overall Storage Capacity for "Commercial" Methane Fields

The overall CO_2 storage capacity for "commercial" methane fields is the sum of equation (10) and equation (11):

$$Q_{CO_2} = Q_{replacement} + Q_{ECBM} \qquad (12)$$

Table 5-1 Coal Rank, CO2/CH4 Ratio, and ECBM Recovery Factors

(1) Coal Rank	(2) CO2/CH4 Ratio	(3) ECBM Recovery Factor ("Commercial" Methane Fields)	(4) ECBM Recovery Factor ("Non-Commercial" Methane Fields)
Low-volatile (LV)	1:1	50%	25%
Medium-volatile (MV)	1.5:1	55%	32%
High-volatile A (HVA)	3:1	61%	37%
High-volatile (HV)	6:1	67%	42%
Sub-bituminous (Sub)	10:1	100%	74%

5.4.2 CO_2 Storage in "Non-Commercial" Methane Fields

"Non-commercial' methane fields, though not economically viable for primary methane production, can generate room for CO_2 storage via CO_2-ECBMR. By substituting a zero for the PRF in equation (11), a modified version of the equation (13) can be used to estimate the CO_2 storage capacity for "non-commercial" methane fields.

$$Q_{ECBM} = r * e * V_{OGIP} * ERF * \rho_{CO_2} \qquad (13)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery
R = CO_2/CH_4 ratio
e = accessible portion of 'non-commercial' area
V_{OGIP} = original gas in place (volume in standard condition)
ERF =ECBM recovery factor (%)
ρ_{CO_2} = CO_2 density (in standard condition)

The default value for *e* for "non-commercial" methane fields is 0.5 (unlike 0.75 for "commercial" fields). Column (4) of Table 5-1 gives the ECBM recovery factor for "non-commercial" methane fields by coal rank, which is less than the corresponding ECBM recovery factor for "commercial" methane fields within each coal rank type.

5.4.3 The "Adopted" Approach to Estimate the CO_2 Storage Capacity for "Commercial" Methane Fields

Equations (10) and (13) use data on the original gas in place in order to estimate the CO_2 storage capacity of methane fields. Just like the case with hydrocarbon fields, however, this data is generally unavailable. For "commercial" methane fields, however data usually available regarding cumulative gas production to date. This cumulative gas production data is used as a lower bound of the ultimately recoverable gas—equivalent to the term "V_{OGIP}*PRF" in equation (4.1). By using this lower bound value of the ultimately recoverable gas, equation (14) gives a very conservative estimate of the CO_2 storage capacity for "commercial" methane fields. Since little data is available for "noncommercial" methane fields, equation (13) is used to estimate the CO_2 storage capacity:

$$Q_{ECBM} = r * e * \tilde{V}_{CGP} * [\frac{PRF + (1 - PRF) * ERF}{PRF}] * \rho_{CO_2} \tag{14}$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery
r = CO_2/CH_4 ratio
e = Voidage replacement and ECBMR efficiency factor
$\tilde{V}_{CGP}$ = cumulative gas production (volume in standard condition)
PRF = primary recovery factor
ERF = ECBM recovery factor
ρ_{CO_2} = CO_2 density (in standard condition)

Equation (14) was used to estimate the CO_2 storage capacity of "commercial" methane fields using cumulative gas production data. The limitation of this approach was that it underestimated the CO_2 storage capacity for "commercial" methane fields, particularly for those in their early stage of production. Moreover, it could not be applied to "noncommercial" methane fields since these fields have no gas production. In Phase II of the study, effort will be put into collecting original gas in place data for methane fields so that the theoretically more sound formulas (4.3) and (4.4) can be used for both "commercial" and "noncommercial" methane fields.

References

Altunin V.V. *Thermophysical properties of carbon dioxide*. Moscow: Publishing House of Standards, 1975 (in Russian).

Holloway, Sam, et.al. 1996. *The Underground Disposal of Carbon Dioxide*, Report for the JOULE II Project CT92-0031.

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6 Annex 6: CO_2 Injection Cost Modeling

6.1 Introduction

This annex documents the CO_2 injection cost estimation tools. The cost estimation modeling for the geologic CO_2 storage options can be broken down into two components: CO_2 injectivity model and storage cost model. We adopt two different methods in developing the CO_2 injectivity model: Law & Bachu method and ARI method.

In this annex:

- Section 6.2 summarizes and compares the Law & Bachu method and ARI method in developing the CO_2 injectivity model based on the CO_2 injection in deep saline aquifers. The injectivity model is used to calculate the injection rate per well and thus the number of wells required.
- Section 6.3 provides a set of capital and O&M cost factors that are used to determine total storage cost based on well number.

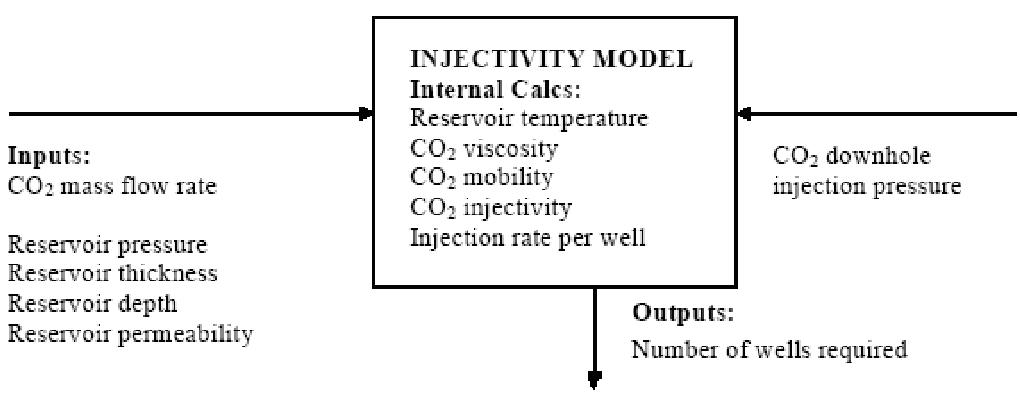
6.2 CO_2 Injectivity Model

We adopt two different methods in developing the CO_2 injectivity model: Law & Bachu method and ARI method. This section summarizes and compares the two methods.

6.2.1 Law & Bachu Method

The Law & Bachu method in developing the CO_2 injectivity model is based on the basic relationship for calculating CO_2 injectivity, downholde injection pressure, and the number of wells required for a given CO_2 flow rate derived by Law and Bachu (1996). It requires inputs for CO_2 mass flow rate, CO_2 downhole injection pressure, and reservoir pressure, thickness, depth and permeability. Figure 6-1 provides the overview of the model, which will be described below in greater detail.

Figure 6-1 Law & Bachu CO_2 Injectivity Model Overview



Given the depth of the reservoir, the downhole injection pressure (dinjprs) is assumed to be equal to the reservoir fracture pressure, which by default is set to be dinjprs (psi) = 0.6*depth (feet).

Step 1: Viscosity Calculation

The viscosity of the CO_2 (visct) at the reservoir conditions is calculated using correlations from V. V. Altunin (1975) that assumes the CO_2 viscosity is a function of the pressure and temperature of the reservoir[12]. In case the reservoir temperature is not given, we estimate the reservoir temperature assuming a surface temperature of 15ºC and a geothermal gradient of 25 ºC /km. In case the reservoir pressure (rsvrprs) is not given, it is by default set to the hydrostatic pressure by the following formula:

rsvrprs (psi) = 0.435*depth (feet).

Step 2: Absolute Permeability Calculation

Next, the absolute permeability is found from (Law and Bachu, 1996)

$absperm = (perm_h \times perm_v)^{0.5}$

where absperm = absolute permeability (mD)

$perm_v$ = the vertical permeability and is equal to 0.3 times the horizontal permeability (mD)

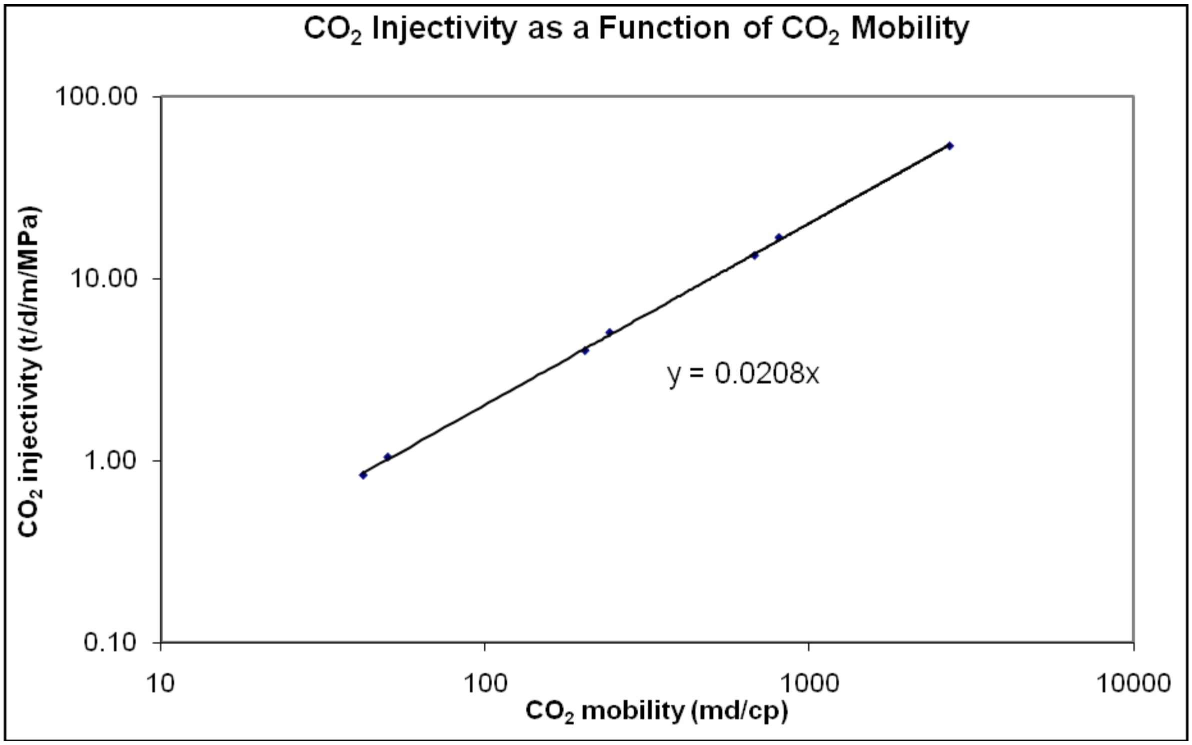
$perm_h$ = the given horizontal permeability (mD)

Step 3: Injectivity Calculation

A relationship, derived by Law and Bachu (1996), is used to determine CO_2 injectivity from CO_2 mobility. This relationship is shown in Figure 6-2.

[12] The CO_2 viscosity was calculated using a computer code (CO_2 Property Calculator) developed by Victor Malkovsky of the Institute of Geology of Ore Deposits, Petrography, Mineralogy and Geochemistry (IGEM) of the Russian Academy of Sciences, Moscow. We converted his FORTRAN code into Visual Basic.

Figure 6-2 CO_2 Injectivity as a Function of CO_2 Mobility



The equation for CO_2 injectivity is

injectivity=0.0208*mobility
mobility= absperm/visct

where injectivity = the mass flow rate of CO_2 that can be injected per unit of reservoir thickness (thickness) and per unit of downhole pressure difference (dinjprs – rsvrprs) (t/d/m/MPa)

mobility = CO_2 mobility (mD/cp)

Step 4: Well Number Calculation

Given the CO_2 injectivity, the CO_2 injection rate per well (injtd) and then the number of well required for a given CO_2 flow rate (numwell) could be found from:

numwell = CO_2flow / injtd
Injtd = injectivity x thickness x (dinjprs – rsvrprs)

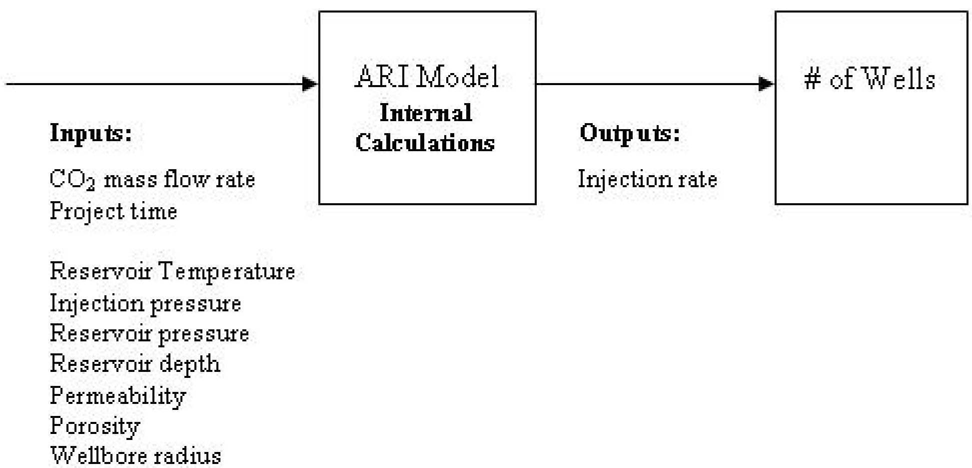
where numwell = number of wells required for a given CO_2 flow rate
CO_2flow = given CO_2 flow rate (tonne/day)
injtd = CO_2 injection rate per well (tonne/day)
thickness= reservoir thickness (m)
dinjprs = downhole injection pressure (MPa)

rsvrprs = initial reservoir pressure (MPa)

6.2.2 ARI Method

The method developed by Advanced Resources International, Inc. (ARI) is based on the injection of CO_2 at super-critical conditions into a liquid-filled, possibly infinite aquifer. The ARI method wants to find out the CO_2 injection rate into the aquifer in a given period. Figure 6-3 provides the overview of the ARI model, which will be described below in greater detail.

Figure 6-3 ARI Injectivity Model Overview



The ARI method defines the domain of interest as:
An infinitely large aquifer system with one well located in the center

- $r = r_w$ at wellbore
- $r = \infty$ infinite at the reservoir boundary
- $P = P_i$ (initial reservoir pressure) at $r = \infty$
- $P = P_i$ at t=0 for any r

Using the above boundary conditions, the ARI injectivity model can solve the flow equation in terms of dimensionless variables.

Step 1: Pseudo Pressure Calculation

$$\Psi = \int_0^p \frac{2pdp}{\mu_i z_i}$$

Where Ψ = pseudo pressure (psia^2/cp)

μ_i = viscosity (cp)

z_i = compressibility factor

We calculate μ_i and z_i corresponding to each pressure (p) and then take integral to calculate the pseudo pressures. The viscosity and compressibility factor at each reservoir pressure condition are calculated using correlations from V. V. Altunin (1975) that assumes both CO_2 viscosity and compressibility factor are functions of the pressure and temperature[13]. We need to calculate pseudo pressures corresponding to initial reservoir pressure (p_1) and downhole injection pressure (p_2) in each case.

Step 2: t_d Calculation

$$t_D = \frac{\lambda k t}{\Phi \mu c r_w^2}$$

where

λ = constant ($2.637*10^{-4}$)

k = permeability (mD)

t = project time (hours) (default: 87600 hours or 10 years)

Φ = porosity

μ = viscosity at the reservoir condition[14] (cp) (note: this is a constant number for each reservoir)

c = compressibility ($psia^{-1}$) (note: this is different to compressibility factor and is constant for each reservoir) (default: 0.000079 psi^{-1})

r_w = radius of wellbore (ft) (default: 0.33 ft)

Step 3: Injection Rate Calculation

$$q_{sc} = \frac{(\Psi_2 - \Psi_1) k h}{\gamma T P_t}$$

where q_{sc}= average CO_2 injection rate (MMscfd)

Ψ_1 = lower pseudo pressure ($psia^2$/cp) (calculated in step 1 corresponding to initial reservoir pressure)

Ψ_2 = higher pseudo pressure ($psia^2$/cp) (calculated in step 1 corresponding to downhole injection pressure)

---

[13] The CO_2 viscosity and compressibility factor were also calculated using the CO_2 Property Calculator.
[14] The CO_2 viscosity at the reservoir condition was also calculated using the CO_2 Property Calculator.

K = permeability (mD)

γ = constant ($1.422*10^6$)

T = temperature (°R = °F+460)

P_t = ½($\ln t_D$+0.80907) given $1/4t_D << 0.01$ (t_D calculated in step 2)

Step 4: Well Number Calculation

$n = m / q_{sc}$

where n = number of wells required for a given CO_2 flow rate

m = given CO_2 flow rate (tonne/day)

q_{sc} = average CO_2 injection rate per well (tonne/day)

6.2.3 Comparison

Table 6-1 presents a comparison of the results estimated by the two methods for 4 different illustrative cases.

Table 6-1 Comparison of Law & Bachu Method and ARI Method

		Case 1	Case 2	Case 3	Case 4
Law & Bachu Method					
Depth	m	1094	2209	1239	1784
Thickness	m	76.20	65.84	171	42
Temperature	°F	95.5	95.5	95.5	95.5
Permeability	mD	40	20	22	0.8
Initial Reservior Pressure	Mpa	10.78	25.00	8.4	11.8
Downhole Inection Pressure	Mpa	14.86	30.00	16.83	24.23
Intermediate Pressure	Mpa	12.82	27.50	12.61	18.02
Viscosity	cp	0.062	0.093	0.043	0.065
CO2 injection rate per well	**t/d**	**2300**	**809**	**8376**	**73**
ARI Method					
Depth(ft)	ft	3590	7247	4065	5853
Thickness(ft)	ft	250	216	561	138
Temperature	°F	95.5	95.5	95.5	95.5
Temperature	°R	555.5	555.5	555.5	555.5
Time	hours	87600	87600	87600	87600
Porosity	fraction	0.13	0.1	0.1	0.1
Permeability	mD	40	20	22	0.8
•	constant	0.0002637	0.0002637	0.0002637	0.0002637
•	constant	1422000	1422000	1422000	1422000
Wellbore Radius	ft	0.33	0.33	0.33	0.33
Compressibility	$psia^{-1}$	0.000079	0.000079	0.000079	0.000079
Viscosity	cp	0.062	0.093	0.043	0.065
Initial Reservior Pressure (p1)	psia	1562	3623	1217	1710
Downhole Inection Pressure (p2)	psia	2154	4348	2439	3512
• 1	$psia^2/cp$	198046314	566799068	125009188	227487563
• 2	$psia^2/cp$	311985578	683197195	363953386	548514888
tD		13406538049	5790666951	13702079976	327955642
1/4tD<<0.01		yes	yes	yes	yes
Pt		12.06	11.64	12.07	10.21
Qsc	MMscfd	119.56	54.67	309.18	4.39
CO2 injection rate per well	**t/d**	**6642**	**3037**	**17177**	**244**

6.3 Cost Model

The injection cost model consists of two types of costs, each with several components. The costs are classified as either capital or annual costs. Capital costs include: site evaluation and screening; drilling; and injection equipment. Annual costs include ongoing operating and maintenance costs for the injection wells. This cost model builds and extends from the original injection cost model proposed in *Heddle et al., 2003*. Each of the components is described below.

The model was for the most part built on two main sources of information, which were the best available to us at the time: the 2004 AIP Joint Association Survey on Drilling Costs, and the 2005 EIA Costs and Indices (see references for full details). In addition, we have applied costing methodology from ARI Basin Studies reports in this model (where indicated below).

Capital Costs

Capital costs include detailed site characterisation, drilling, and injection equipment costs. Each of these is described below.

Detailed Site Characterization Cost

The total site characterisation / evaluation cost was estimated by Smith *et al.* (2001) to be $1,685,000 (per site). This estimate is based on the following activities (extracted from the above-mentioned publication):

Preliminary site screening: $330,000

- Definition of screening factors
- Collection of documents describing candidate areas
- Evaluation of candidates with respect to screening factors
- Prepare report identifying and ranking suitable sites.

Candidate evaluation: $1,355,000

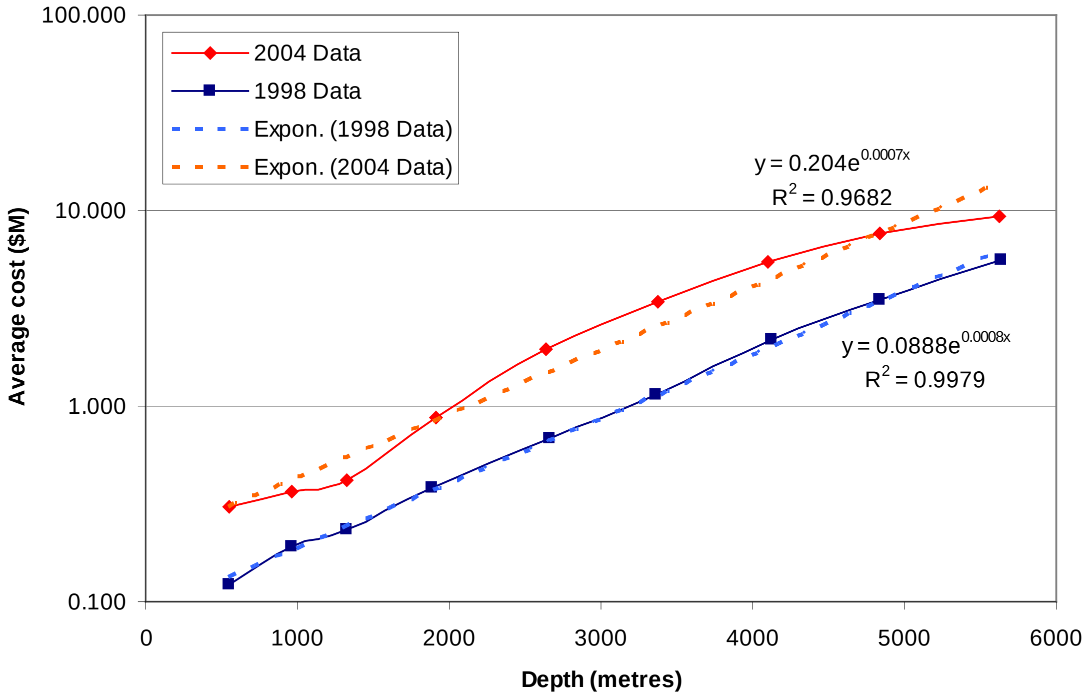
- Install 10 groundwater sampling wells in USDW associated with the site
- Collect and analyze water samples from the USDW
- Install one test well in the saline aquifer
- Log the test well
- Collect and analyze liquid samples from the injection zone
- Collect and analyze mineral samples from the injection zone
- Perform an injectivity test in the injection zone
- Perform surface geophysical (e.g. seismic) testing of the area
- Install geophones and perform seismic monitoring
- Perform site modelling
- Perform site seismic evaluation
- Prepare candidate evaluation report.

This site characterisation cost was used by the IPCC in preparation of the Special Report on Carbon Dioxide Capture and Storage (2005), and we have also adopted the figure of **$US 1, 685,000 per site** for the current version of the injection costs model.

Drilling Cost

The 2004 API Joint Association Survey on Drilling Costs summary data for the United States was used to produce the drilling costs model for new wells to be used for carbon dioxide sequestration. The methodology laid out it Heddle *et al.* (2003) was followed, and the costs updated from the 1998 figure to the 2004 figures (Figure 6-4). Using aggregate US-wide data, which was reported as number of wells, total footage, and total cost by depth interval, the chart below was produced, for wells of depth 554-5633m (following Heddle et al., 2003).

Figure 6-4 Average drilling cost per well for wells of depth 554-5633m, aggregated over the U.S.



Previous drilling cost (from 1998, blue) and updated cost (2004, red) are shown on the chart. Equations of the trendlines give the cost calculation.

Using then a line of best fit, the drilling cost for any onshore location in the US becomes:
Drilling Cost ($M/well) = $0.204e^{0.0007x}$ (where x is the depth of the well in meters).

Lease Equipment Cost

The lease equipment cost includes gathering lines, header, electrical service, and water pumping system. The lease equipment cost in the injection costs model has been revised and simplified from the version found in Heddle et al., 2003. In the current model, we have used the Advanced Resources International (ARI) method, which can be found in the ARI "Basin Studies for EOR, Permian Basin" report (ARI, 2005). Although ARI adapt this calculation to each different region, we have used only the base case, for which there was data (west Texas). The ARI method is based on EIA Cost and Indices report (2005), as below:
Lease Equipment Cost ($/well) = 9,277 + 48 × depth (meters)

Ongoing (annual) costs

The annual costs part of the injection cost model consists of the ongoing operation and maintenance work associated with injection of CO_2. These costs are all based on the EIA Costs and Indices dataset. hese activities include: normal daily expenses (such as consumables – fuel, water, chemicals, power; labour, supplies; supervision and overhead), surface maintenance and repair (layout, supplies and services, equipment usage, etc.); and subsurface maintenance and repair, including periodic well workovers. In our previous model (Heddle et al., 2003), these costs were all reported and calculated separately. e have decided to update this by adapting ARI's O&M cost, as below, to simplify this part of the model.

The O&M cost for this version of the injection cost model has been adapted from that developed by ARI in their Basin Studies reports. RI used the base case from East Texas EOR operations to calculate the O&M costs and adapt them to different regions in the US. e have applied simply the base case East Texas cost to the entire US, so there will be areas which are underestimating the cost (most likely), and areas where the cost is overestimated. The cost calculation is based on the EIA Costs and Indices report and is as follows:
O&M Cost ($ / well / year) = 20,720 + 25.61 × depth (meters)

A capital charge of 0.15 was used to annualize the capital cost over the operating life of the injection so that the annual injection cost was 0.15 of its capital cost plus the annual O&M cost.

References

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Smith, L.A., Gupta, N., Sass, B.M., Bubenik, T.A., Byrer, C., Bergman, P., 2001. *Engineering and Economic Assessment of Carbon Dioxide Sequestration in Saline Formations*, presented at the First National Conference on Carbon Sequestration, Washington D.C. http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/IPCCSpecialReportonCarbondioxideCaptureandStorage.htm

7 Annex 7: MIT CO_2 Pipeline Transport and Cost Model

7.1 Overview

This annex documents the CO_2 pipeline transport technology transfer package. The package contains the following contents:

- National CO_2 transportation obstacle layers;
- Module to calculate pipeline diameter;
- Module to identify the least-cost route connecting a CO_2 source to a given sink;
- Economic module to calculate the CO_2 transport pipeline construction cost and O&M cost.

Figure 7-1 Pipeline Transport Overview Diagram

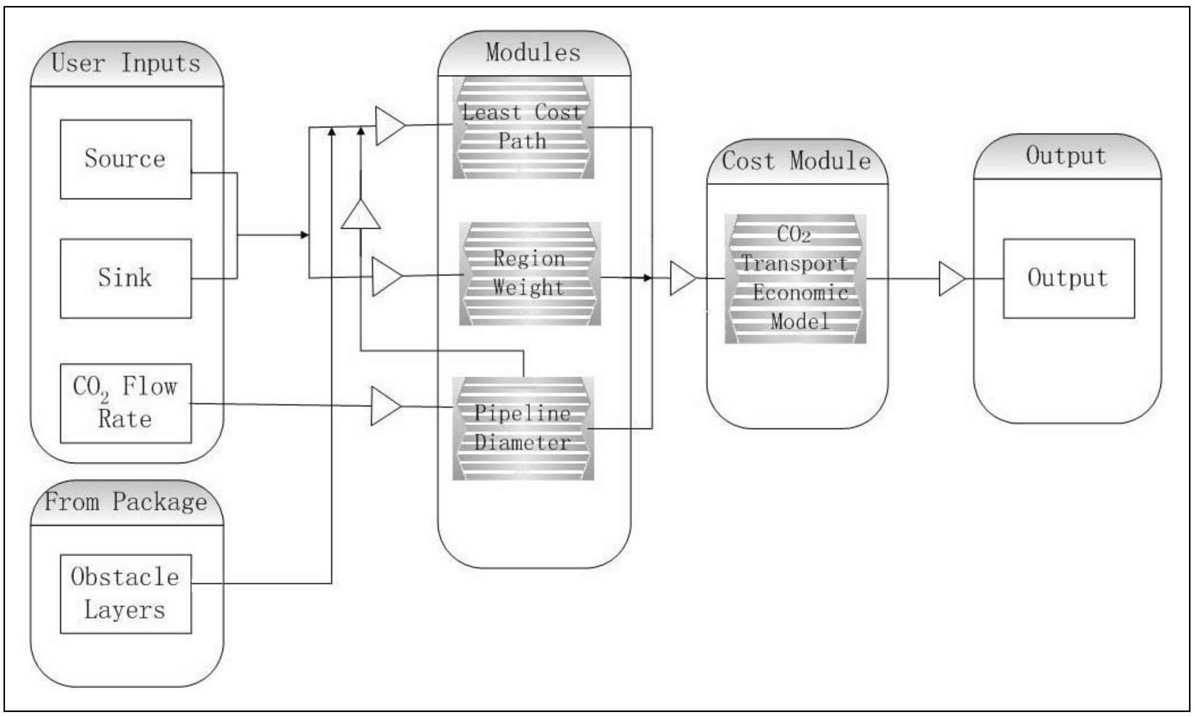


Figure 7-1 gives an overview of the structure of the CO_2 transport package. The package delivers users with a data CD that contains national obstacle layers and an ArcGIS program that calculates the least cost CO_2 transport path.

In this annex:

- Section 7.2 provides a user manual for the CO_2 transport package;
- Section 7.3 presents the methodology to calculate CO_2 pipeline diameter, the national CO_2 transport obstacle layers construction, and the least-cost route selection;
- Section 7.4 documents two economic correlations (MIT & CMU) used to calculate the CO_2 transport pipeline construction and O&M costs.

7.2 *Manual*

7.2.1 What is inside the package CD

A CD will be delivered for ArcGIS CO2 Transport Package. In the CD, there are two folders, named "Program" and "ReferencedData". "Program" folder contains an ArcGIS document file "co2packagev1.mxd", and two required data layers for running the program: states (polygon), and pathcost (raster). "ReferencedData" folder contains 7 data layers which were used to generate the pathcost (raster) layer: urban, water, state parks, slope, rail, highway, federal parks. Please note that the layers in "ReferencedData" folder are just for users' reference, and are not needed for the transport tool to run.

7.2.2 System Requirements

Hardware

Minimum Requirements

- Platform PC-Intel
- Memory 128 MB RAM
- Processor 450 MHz

Recommended Requirements

1) Same as above except for item(s) identified below:
2) Memory 256 MB RAM (or higher)
3) Processor 650 MHz (or higher)

Software

- Operating System Windows NT 4.0 with Service Pack 6a (or) Windows 2000 (or)Windows XP (Home Edition and Professional)
- ESRI ArcGIS 9.1 with Spatial Analysis Extension

7.2.3 Installation

MIT CO_2 Transportation Package was developed as a tool within ArcGIS 9.1. There is no need to install this tool. Just copy the "program" folder in the delivered CD to your working directory, and double click "co2packagev1.mxd" to open ArcGIS and run the tool.

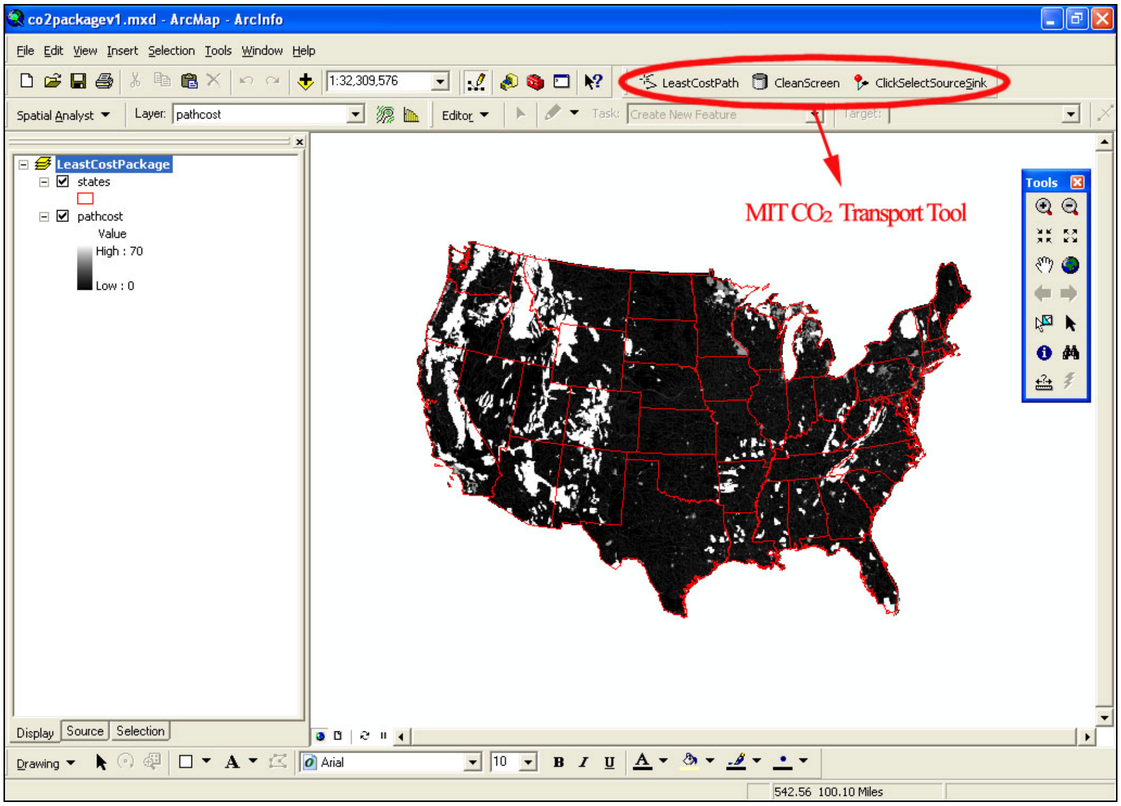
7.2.4 Manual

Please follow below procedures to use the tool:

(1) Open the document

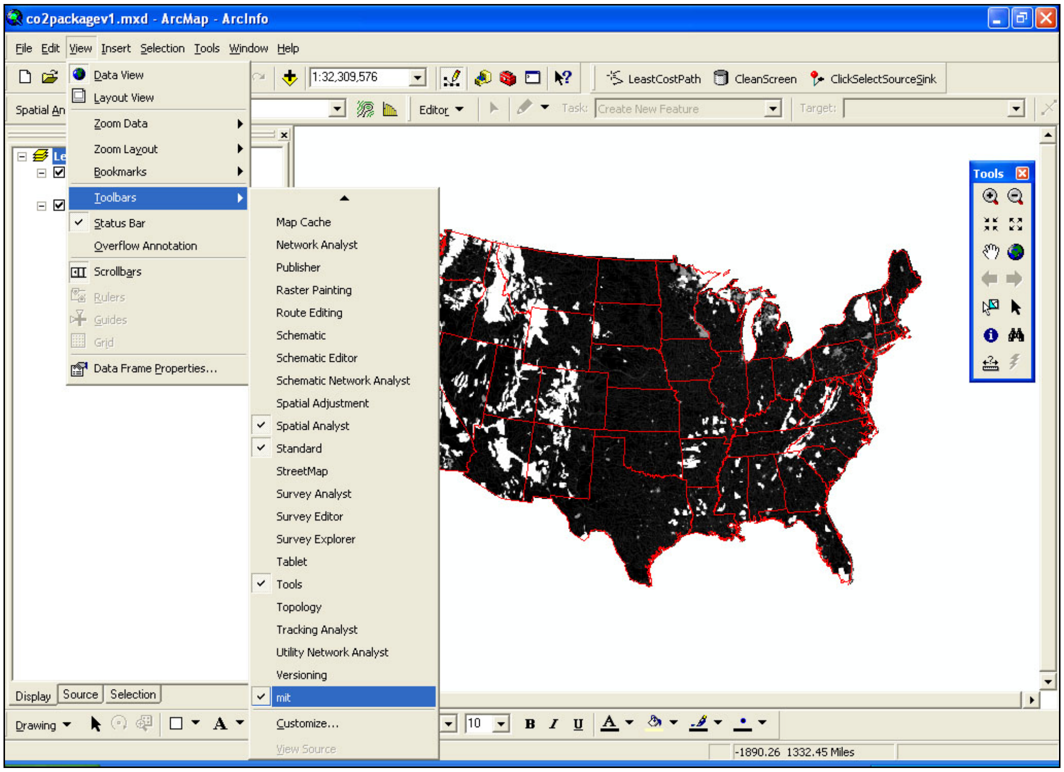
Double-click "co2packagev1.mxd" to open it in ArcGIS 9.1. After you open it, you should see the MIT CO_2 tool bar as shown in Figure 7-2.

Figure 7-2 MIT CO_2 Transport Package Toolbar



If you cannot find this toolbar, please go to the menu View/Toolbars, (shown as Figure 7-3), select "mit" to display the tool bar.

Figure 7-3 Load the CO_2 Transport tool bar



(2) Open the package

Three tools: LeastCostPath , CleanScreen , ClickSelectSourceSink can be found in the tool bar.

- *LeastCostPath* is the only entry to the Package. Click it to start the transport package, and the interface of the package is shown as Figure 7-4.
- *CleanScreen* is the tool used to clean the temporary source/sink points left on the screen from previous runnings.
- *ClickSelectSourceSink* is used by the program to select a source/sink location by mouse-click on the screen. Users will use it indirectly by clicking "Select by Mouse" on the tool interface (please see Figure 7-4).

(3) Set parameters for the calculation

To calculate the cost, four groups of parameters need to be set at first. They are: locations of source and since points (this version just supports one source and one sink); CO_2 flow rate; cost correlation to be used; and the directory for saving the least cost path (optional).

<u>Set location of source and sink</u>

There are two ways to select the locations of source and sink. Users can click the "Select by Mouse" button, and click on the screen. The current location of the mouse pointer will be stored and a message box will appear to tell user "You selected a source point" (or "You selected a sink point" depending on whether you click button 2 or 4 in Figure 7-5);

Or, users can use a point layer to choose the source/sink location. Choose the layer name from the drop-down menu (as 1, 3 in Figure 7-5). If the layer contains one point, this point will be used as the source/sink location (1 for the source, 3 for the sink); If the layer contains more than one point, and one point is selected, the selected point will be used as the source/sink location (1 for the source, 3 for the sink); If the layer contains more than one point, and no point is selected or more than one points are selected, an error message will be displayed.

Set the CO_2 flow rate
Flow rate of the pipe can be defined in the text box beside "Flow Rate" (as 5 in Figure 7-5). Only numbers are allowed, otherwise, an error message will be displayed. The unit of flow rate can also be set by choose from the drop-down menu as labeled 6 in Figure 7-5.

Choose cost calculation method
There are three methods provided in the tool to calculate the estimated cost for CO_2 transport pipe: CMU Correlation, MIT Correlation, and User Defined Method. (please reference to chapter 4 in this document for details). If User Defined Method is to be used, users need to input the cost per inch per mile.

Save the least cost path shape (optional)
After running the tool, a polyline represents the least cost shape will be generated to be saved in a layer. If you want it to be saved in specific location, please select "save least cost path shape", and define the directory in the box as 8 in fig. 2.4. Otherwise a temporarily layer named "Pipe_LeastCostPath" will be generated to save the shape, which will be replaced at next running.

(4) Run the calculation
When it is ready to run the tool, just click the "Run" button on the tool interface. Figure 7-6 shows an example result page for one running. The cost results will appear in the "Results" section in the tool, and the least cost path shape will be saved in a layer named "Pipe_LeastCostPath".

If users want to compare the results from different methods, they can rerun the tool after changing the methods but use the same source and sink.

Note: If you just see a "toolpolygontemp" layer, but cannot see the result, first make sure you are running ArcGIS 9.1 with Spatial extension, then clear your user temporary folder, which is: C:\Documents and Settings\<<your-computer-user-name>>\Local Settings\Temp, then rerun the program. If the program still does not work, please see section 2.5.

Figure 7-4 CO_2 Transportation Tool Interface

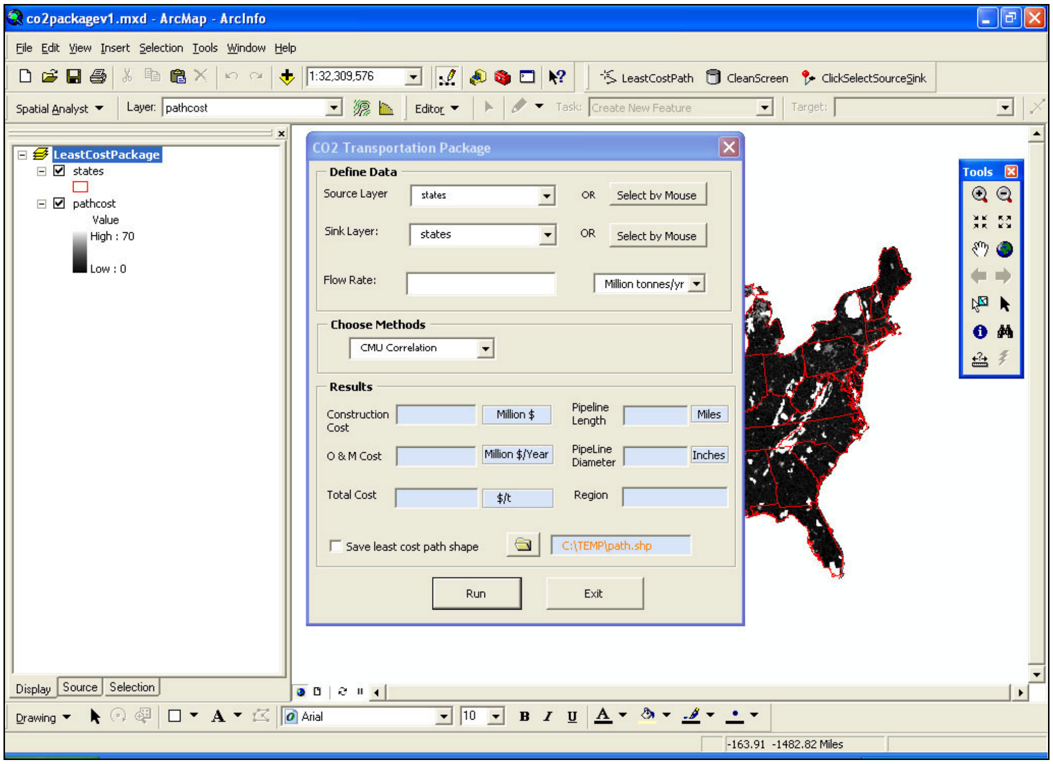


Figure 7-5 CO_2 Transportation Tool Interface components

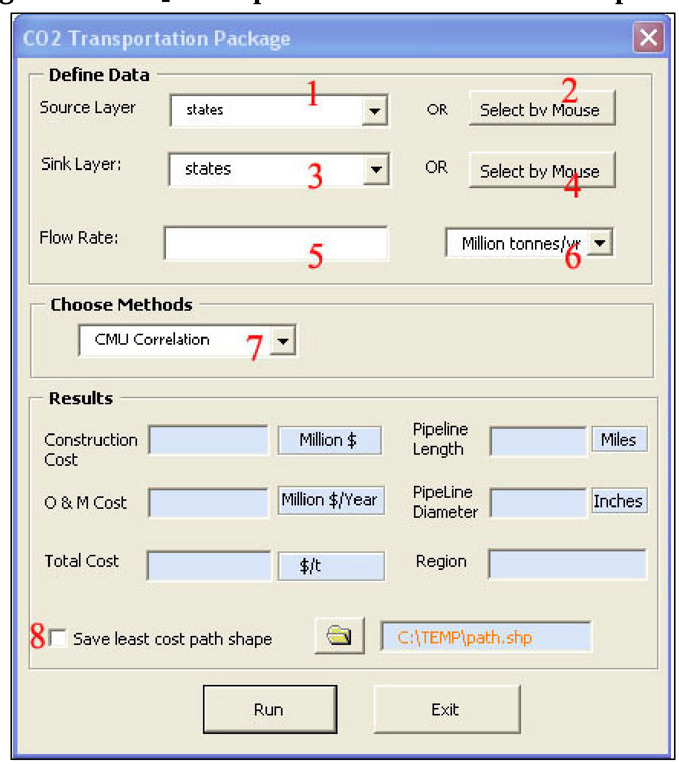
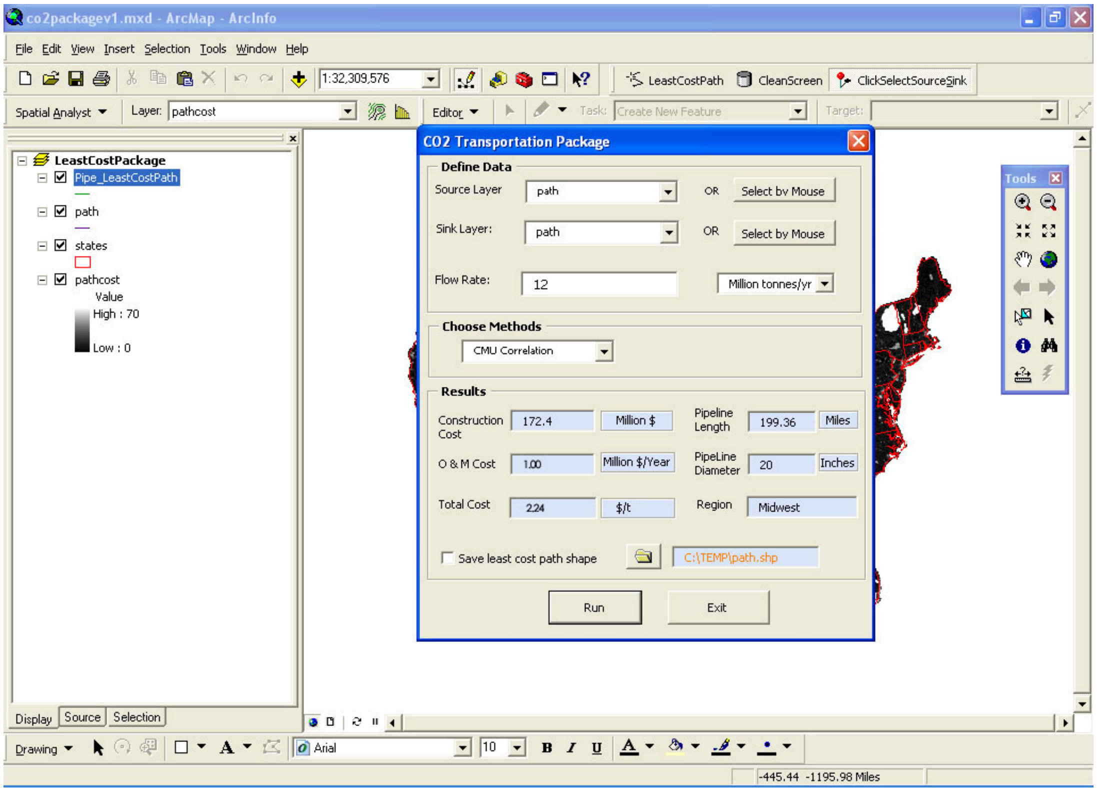


Figure 7-6 An Example Result



7.3 Methodology: Pipeline Diameter and Least-cost Route

7.3.1 Pipeline Diameter Calculation

The pipeline design capacity is one of the first design criteria needed for CO_2 transport cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transport requirements of their corresponding CO_2 emissions sources.

Equation (1) gives the relationship among pipeline diameter (*D*), maximum allowable pressure drop (• *P*/• *L*), CO_2 mass flow rate ($\dot{m}$), CO_2 density (•), and the Fanning friction pressure (*f*) can be characterized by the following formula (Heddle *et.al.*, 2003):

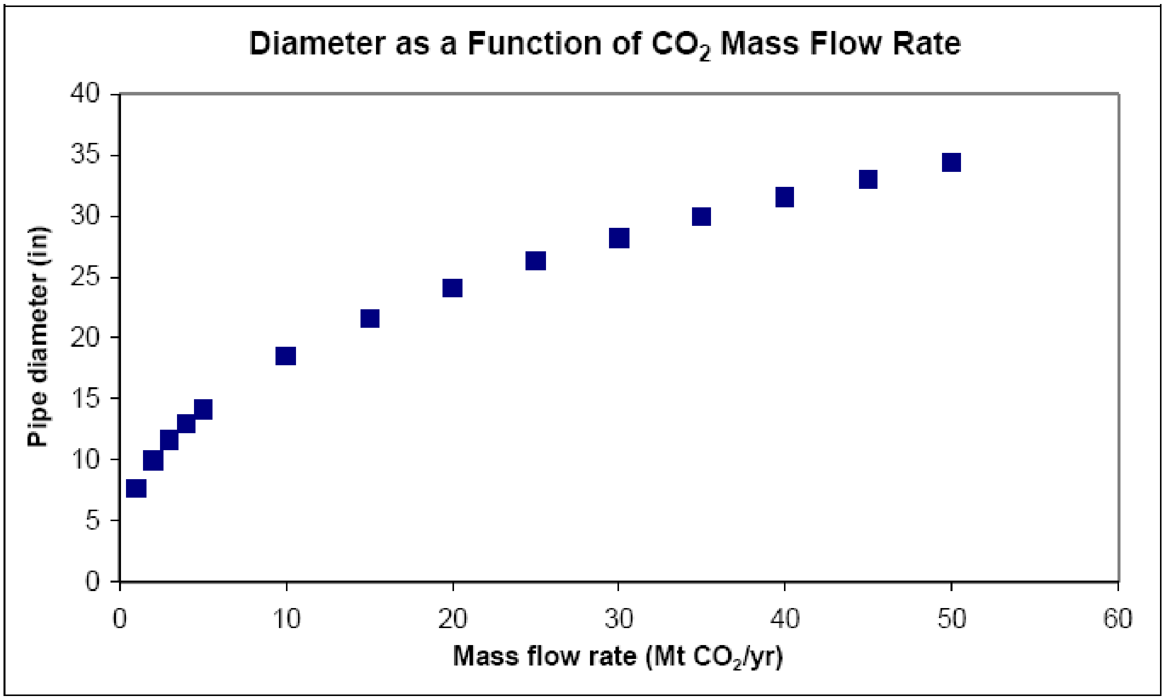
$$\frac{\Delta P}{\Delta L} = \frac{32 f \dot{m}^2}{\pi^2 \rho D^5} \qquad (1)$$

In equation (1), the default maximum allowable pressure drop per unit length (• *P*/• *L*) is set to be 49Pa/m. The default CO_2 density (•) is assumed to be 884 kg/m. calculated from MIT CO_2

property calculator[315], The Fanning friction pressure is found by using the relationship based on the Moody chart (see Heddle *et.al.*, 2003).

Figure 7-7 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. In this study it is assumed that standard type gas industry pipelines will be used for CO_2 transportation. Based on the power function in Figure 7-7, Table 7-1 gives the breakdown of the CO_2 flow rate for each pipeline standard diameter within the range from 4 to 36 inches. For any given maximum CO_2 flow rate, Table 7-1 provides a look-up table to determine the appropriate pipeline diameter. In the future work, the package will allow users to define the maximum allowable pressure drop.

Figure 7-7 Maximum Mass CO_2 Flow Rate as a Function of Pipeline Diameter



[15] According to the MIT CO2 property calculator, the CO2 density of 884 kg/m^3 corresponds to the status of a temperature of 25 ºC and a pressure of 158 bar.

Table 7-1 Pipeline Diameter and the CO2 Flow Rate Range

Pipeline Diameter (inch)	CO_2 Flow Rate (Mt/yr)	
	lower bound	upper bound
4		0.19
6	0.19	0.54
8	0.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

7.3.2 National CO_2 Transport Obstacle Layers Construction

In addition to the diameter and capacity, pipeline construction costs vary considerably according to local terrains, crossings (waterways, railways and highways), protected areas (wetland, national or state parks), and populated places[16]. The data CD of the CO_2 transport package contains three types of obstacles: land slope, protected areas, and crossings. In order to use this land obstacle data to help select the optimal pipeline routes, the continuous obstacle layers were rasterized into 1km by 1km cells. Table 7-2 lists the obstacle layers, their raw data sources, and the associated relative cost factors corresponding to an 8 inch pipe.

[16] The populated places data is from US Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

Table 7-2 Obstacle Conditions and Their Relative Cost Factors

Construction Condition		Raw Data Source	Cost Factor
Base Case			1
Slope		ESRI Digital Elevation Model	
	10-20%		0.1
	20-30%		0.4
	>30%		0.8
Protected Area			
	Populated Place	ESRI Data & Maps	15
	Wetland	USGS LULC Data	15
	National Park	ESRI Data & Maps	30
	State Park	ESRI Data & Maps	15
Crossing			
	Wateway Crossing	ESRI Data & Maps	10
	Railroad Crossing	ESRI Data & Maps	3
	Highway Crossing	ESRI Data & Maps	3

Note: [1]Values and/or methodology may be updated after working with Kinder Morgan later.
[2]Values are based on 8-inch diameter pipelines.

7.3.3 Least-cost Pipeline Route Selection and Length Calculation

The total pipeline construction cost factor for a cell is the sum of the base case cost factor and the cost factors of all of the obstacles that exist in the cell. The CO_2 transport package assumes that the ***absolute*** additional obstacle costs are independent of pipeline diameter. So the ***relative*** cost factors have a reverse relationship with pipeline diameter. Using the weighted cost layer calculated above, the CO_2 transport package calls the spatial analysis function in ArcGIS determine the least-cost pipeline route for connecting each source and sink. Figure 7-8 shows the procedures to identify the least-cost CO_2 pipeline transport route in ArcGIS. The least-cost route length and the pipeline diameter will be used in the CO_2 transport economic model to determine the pipeline construction and O&M costs.

Figure 7-8 Procedures to Identify the Least-cost Route

1. Pipeline diameter is calculated based on CO_2 flow rate;
2. Obstacle layers' relative cost factors are adjusted according to pipeline diameters;
3. All obstacle layers are aggregated to get a total cost raster layer;
4. Direction (back link) raster layer is calculated;
5. Least-cost path is identified by using *CostPath* function in ArcObject;
6. Least-cost route length is fed back to the total cost model to get the total cost.

7.4 Methodology: CO_2 Pipeline Transport Cost

The amount of cost data on CO_2 pipelines in the open literature is very limited. But there is an abundance of cost data for natural gas pipelines. For this reason, land construction cost data for natural gas pipelines were used to estimate the construction costs for CO_2 pipelines. This should be adequate for the screening study as there is little difference between land construction costs for these two types of pipelines. It is worth noting, however, that CO_2 pipelines might be slightly more expensive because of the greater wall thickness needed to contain CO_2, which is transported at higher pressures.

The CO_2 transport package divides the pipeline transport cost into two components: the land construction cost and the O&M cost. Equation (2) gives the formula to annualize the land construction cost over the operating life of the pipeline:

$$\text{Annualized Cost} = \text{Land Construction Cost} * \text{Capital Charge Factor} + \text{O\&M Cost} \quad (2)$$

The package uses a default capital charge of 0.15 and assumes the pipeline O&M cost to be $5,000/mile per year, independent of pipeline diameter (Heddle, *et.al.*, 2003). The package adopts two correlations to estimate the land construction costs for CO_2 pipelines: the MIT correlation and the CMU correlation, which are discussed in details below.

7.4.1 MIT Correlation

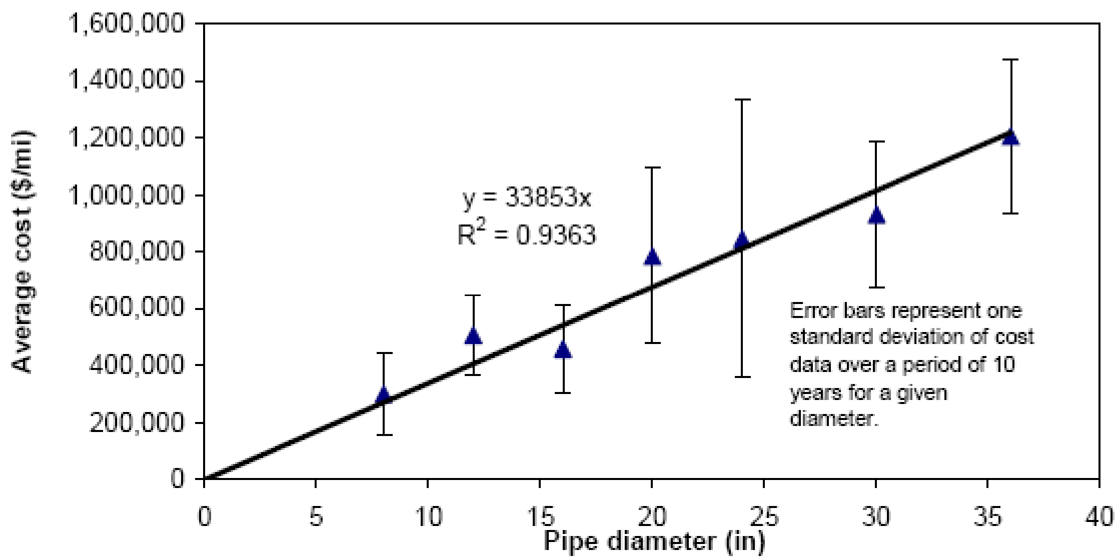
The MIT correlation was developed by the Carbon Capture and Sequestration Technologies Program (CCSTP) at the Massachusetts Institute of Technology. It assumes that the CO_2 pipeline land construction cost has a linear correlation with pipeline diameter and length. Using data for natural gas pipelines consists of cost estimates filed with the United States Federal Energy Regulatory Commission (FERC) and reported in the Oil and Gas Journal, Heddle *et.al.* (2003) estimate the CO_2 pipeline construction cost to be $33,900/in/mile. Figure 7-9 shows the regression analysis of pipeline land construction cost data. Equation (3) provides the formula for the MIT correlation used in the transport package:

$$LCC = \alpha * D * L \tag{3}$$

where α = \$33,853;
D: pipeline diameter in inches (function of CO_2 flow rate);
L: least-cost pipeline route length in miles;

In addition, the package also allows users to replace parameter α with their self-defined values.

Figure 7-9 Regression Analysis of Pipeline Land Construction Cost Data



7.4.2 CMU Correlation

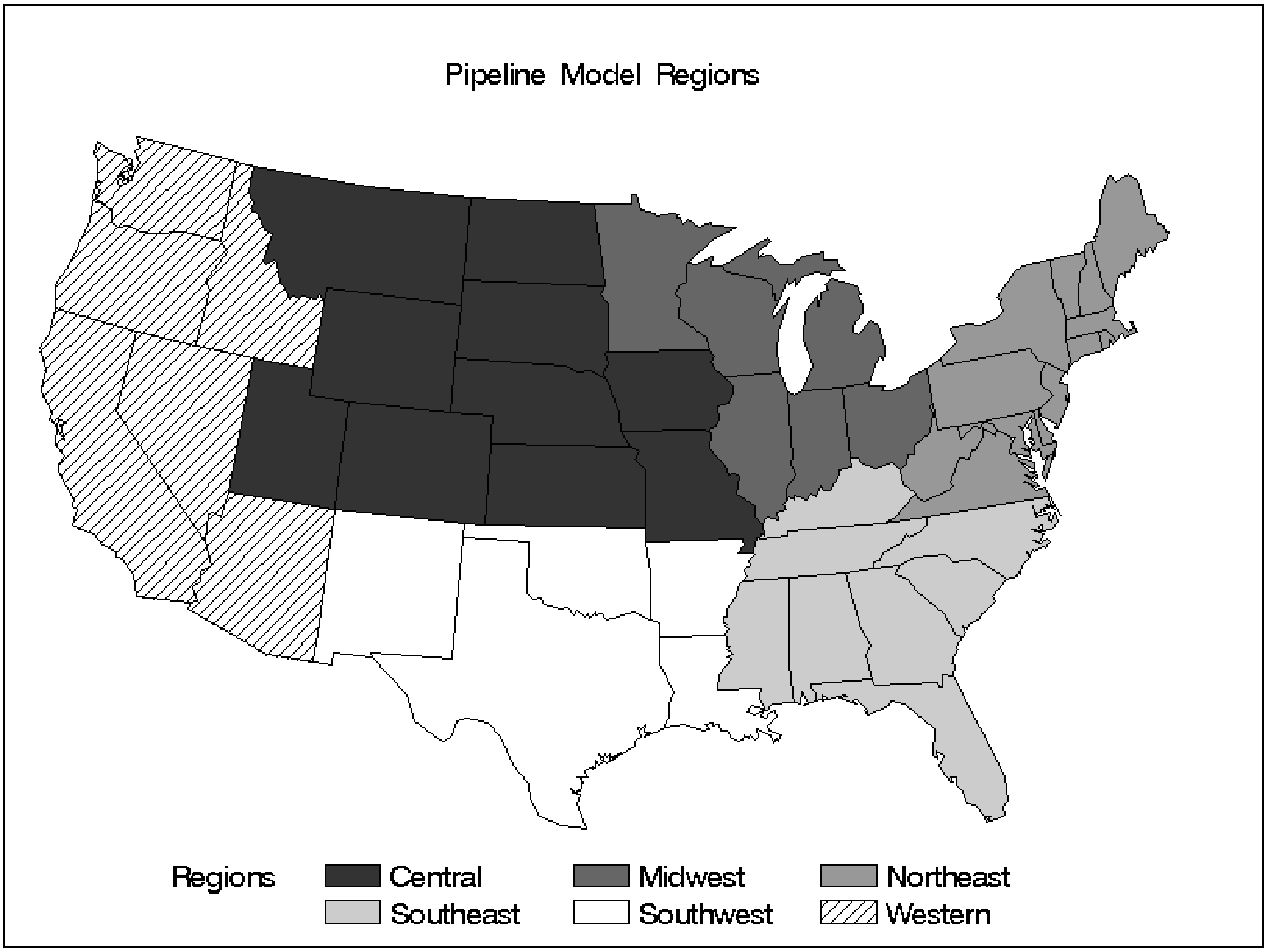
A recent study by Sean McCoy (2006) at the Carnegie Mellon University reexamines the CO_2 pipeline land construction cost using an updated data set—natural gas pipeline project costs published in the Oil and Gas Journal between 1994 and 2003. The CMU correlation looses the linearity restriction in the MIT correlation and allows a double-log (nonlinear) relationship between pipeline land construction cost and pipeline diameter and length. In addition, the CMU correlation takes into account regional differences in CO_2 pipeline land construction costs by using regional dummy variables (see Figure 7-10 for region definitions). Equation (4) provides the formula for the CMU correlation used the transport package:

$$LCC = \beta * D^x * L^y * z \quad (4)$$

where β = \$42,404;
x = 1.035
y = 0.853
z: regional weights

Region	Central	Southwest	West	Midwest	Southeast	Northeast
z values	1.000	1.248	1.341	1.516	1.687	1.783

Figure 7-10 CMU CO2 Pipeline Model Regions



7.4.3 MIT-CMU Comparison

In the CMU correlation, a coefficient estimate of 1.035 for pipeline diameter indicates that the linearity assumption between land construction cost and diameter may be acceptable. However, the coefficient estimate for pipeline length is much less than 1, suggesting that there exist significant economies of scales for pipeline construction. The CMU correlation also indicates substantial regional differences in land construction cost. On average, the pipeline land construction cost in Northeast is 78 percent higher than in Central.

Table 7-3 compares the MIT and CMU prediction results. The CMU predictions of per inch-mile pipeline land construction cost are insensitive to the pipeline diameter but are very sensitive to pipeline length. Given that the pipeline lengths studied in the original MIT correlation range between 100km and 300km, the CMU predictions for pipeline length of 100 mile are more relevant for comparison purposes. It is easy to see that the MIT prediction ranks at the median of the CMU predictions of the 100 mile pipeline case for different regions, indicating that the two prediction results are indeed very similar.

Table 7-3 MIT-CMU Comparison

MIT Correlation Prediction ($/in/mile): $33,853

CMU Correlation Predictions ($/in/mile):

	Central		**Southwest**		**West**	
	100 mile	1,000 mile	100 mile	1,000 mile	100 mile	1,000 mile
8 inch	$23,210	$16,560	$28,962	$20,664	$31,117	$22,202
16 inch	$23,777	$16,965	$29,671	$21,170	$31,879	$22,745
24 inch	$24,116	$17,207	$30,093	$21,471	$32,332	$23,069

	Midwest		**Southeast**		**Northeast**	
	100 mile	1,000 mile	100 mile	1,000 mile	100 mile	1,000 mile
8 inch	$35,194	$25,111	$39,151	$27,934	$41,376	$29,522
16 inch	$36,055	$25,725	$40,108	$28,617	$42,388	$30,244
24 inch	$36,568	$26,091	$40,679	$29,024	$42,992	$30,674

References

Heddle, Gemma, Howard Herzog & Michael Klett. 2003. *The Economics of CO_2 Storage.* MIT LFEE 2003-003 RP.

McCoy, Sean. 2006. *Pipeline Transport of CO_2—Model Documentation and Illustrative Results,* Carnegie Mellon University Manuscript.

8 Annex 8: CO_2 Source-Sink Matching Analysis

8.1 Introduction

This annex documents the CO_2 source-sink matching GIS tools. Based on the previous work on CO_2 source capture and CO_2 sink storage capacity estimation, this section further explores the source-sink allocation and the CO_2 transportation to build up an optimal source-sink matching network that minimizes the full sequestration cost for the network system subject to constraints of the sinks' storage capacity.

In this annex:

- Section 8.2 briefly summarizes the CO_2 source capture and CO_2 sink capacity estimation.
- Section 8.3 presents the CO_2 pipeline transportation cost estimation algorithm.
- Section 8.4 presents an iterative model we developed to (approximately) "optimize" the source-sink matching using the ArcGIS *"spatial analysis tool"*. In practice, the iterative allocation algorithm is performed for EOR sinks and non-EOR sinks separately.

8.2 CO_2 Source Capture and Sink Storage Capacity Estimation

A prerequisite for CO_2 source-sink matching analysis is to determine the targeted source set and sink set and their associated capture or storage capacities. he methodologies the study has developed to estimate the CO_2 source capture capacity and sink storage capacity are documented in details in previous memos. This section, however, briefly summarizes the key features of the process to prepare the targeted CO_2 source set and sink set for the matching analysis.

8.2.1 CO_2 Source Set and Capture Capacity

The targeted CO_2 source set analyzed in the study consists of two major categories: fossil fuel power plants and non-power stationary CO_2 sources. Fossil fuel power plants include three major types: coal-, gas-, and oil-fired power plants. Our database only has information for seven types of non-power stationary CO_2 sources: ammonia, cement, ethylene, ethylene oxide, gas processing, iron & steel, and refineries.

To calculate the amount of captured CO_2 we need to sequestrate from each source, the study assumes a 25-year project lifetime. For concerns of economies of scale in CO_2 capture and sequestration, we restrict power sources to power plants with design capacity over 100MWe and further assume that power plants would operate at 80% of their designed capacity once the capture facility has been installed. eGRID database has the annual CO_2 emission from each power plant under its 2000 operation factor. Based on this information, we calculate the *adjusted annual CO_2 emission* from each power plant when operating at the default 80% operation factor. For non-power CO_2 sources, we estimate the annual CO_2 emission based on the full production capacity of the facilities[17]. The CO_2 capture efficiency is assumed to be 90% all

[17] Certain criteria apply to exclude non-power CO2 sources with the 25-year CO2 capture capacity below a threshold. The threshold was chosen to be 20 Mt for our California study and 5 Mt for our eastern Texas study.

non-pure CO_2 sources and 100% for pure CO_2 sources[18]. The total amount of CO_2 from each source we need to handle therefore equals to the product of the project lifetime, the (adjusted) annual CO_2 emission and the CO_2 capture efficiency.

8.2.2 CO_2 Sink Set and Storage Capacity

The database includes three types of geological sinks: hydrocarbon (oil & gas) reservoirs, saline aquifers, and coalbeds. The previous memo has well-documented the methods we developed to estimate the CO_2 storage capacity for each of these three types of geological sinks. The targeted CO_2 sink set included in the source-sink matching analysis includes all sinks with estimated CO_2 storage capacity beyond the minimum of the 25-year CO_2 capture capacities from sources in the targeted CO_2 source set described above.

8.3 CO_2 Pipeline Transportation Costs

In cases where the CO_2 source is not co-located with an appropriate sink, large quantities of CO_2 will need to be transported from the source to the sink for sequestration. Underground pipelines are considered the most economical means of transporting such large quantities of CO_2, and a pipeline network would be necessary for carbon sequestration to be feasible. Pipeline construction entails significant capital costs, and this section presents models and methods to estimate the CO_2 pipeline transportation costs based on key pipeline variables.

8.3.1 Transport Pipeline Design Capacity

The pipeline design capacity is one of the first design criteria needed for cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transportation requirements of their corresponding CO_2 emissions sources. For pipelines originating at refineries, cement, and lime plants, the pipeline design capacity is set equal to the 2002 CO_2 emission multiplied by a default capture efficiency (90%). For power plants, the pipeline design capacity is calculated as follows:

$$VC_{CO2} = \frac{VE_{CO2}^{2002}}{OE^{2002}} * CE_0 \qquad (1)$$

where VC_{CO2} = Maximum CO_2 flow rate (t/yr);
VE_{CO2}^{2002} = 2002 annual CO_2 emission (t);
OE^{2002} = 2002 plant operating factor;
CE_0 = Default CO_2 capture efficiency (90%)

Equation (1) gives the maximum CO_2 flow rate (in terms of tonne/yr) for a power plant operating at its full design capacity. The required pipeline capacity is an overestimate since plants usually operate below their maximum design capacity.

[18] In the database we analyzed, pure CO_2 sources include ammonia and gas processing plants

8.3.2 Pipeline Diameter Calculation

Figure 8-1 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. In this study it is assumed that standard type gas industry pipelines will be used for CO_2 transportation (True, 1998). Based on the power function in Figure 8-1, Table 8-1 gives the breakdown of the CO_2 flow rate for each pipeline standard diameter within the range from 4 to 36 inches. For any given maximum CO_2 flow rate, **Error! Reference source not found.** provides a look-up table to determine the appropriate pipeline diameter.

Figure 8-1 Maximum Mass CO_2 Flow Rate as a Function of Pipeline Diameter

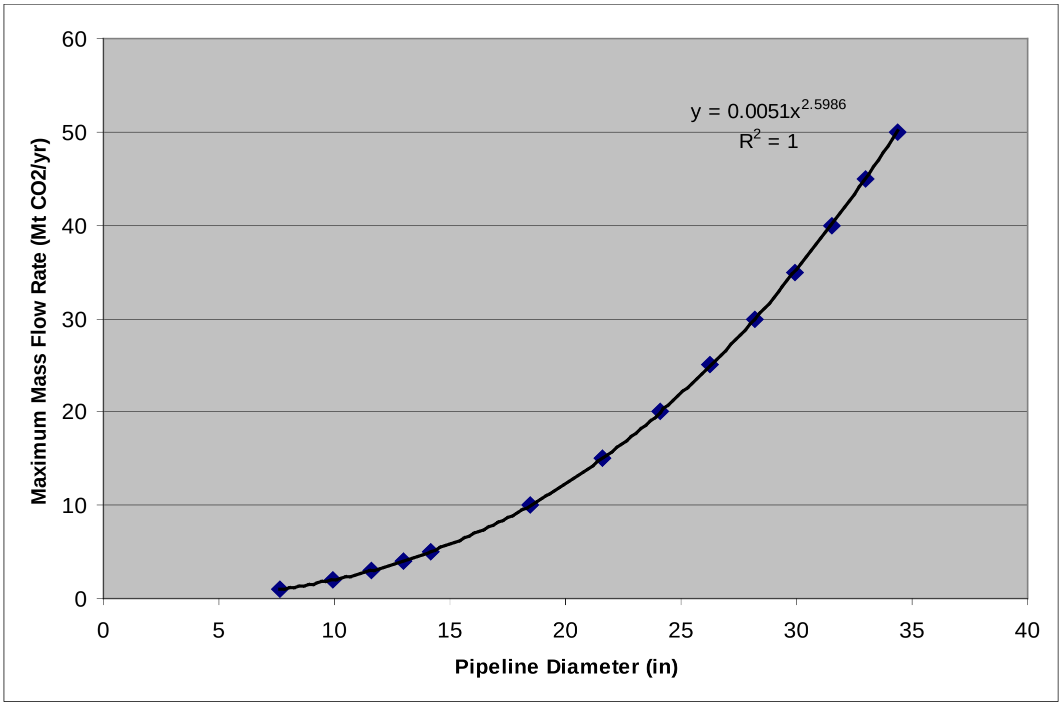


Table 8-1 Pipeline Diameter and the CO2 Flow Rate Range

Pipeline Diameter (inch)	CO_2 Flow Rate (Mt/yr)	
	lower bound	upper bound
4		0.19
6	0.19	0.54
8	0.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

8.3.3 Obstacle Layer Construction

In addition to the diameter and capacity, the terrain being traversed by a pipeline is another significant pipeline construction cost variable. These costs vary considerably according to the local terrain and are also affected by the presence of buildings or infrastructure. Pipeline construction is more expensive in hilly areas than on flat plains. In order to reduce complications and costs, a pipeline's route should avoid passing through populated places[19], wetlands, and national or state parks. In order to account for such obstacles in the study, the locations and characteristics of these obstacles were loaded into Geographic Information System (GIS) software. Using the GIS software the costs for traversing such obstacles during pipeline construction were combined into a single obstacle data layer. This obstacle layer reflected three types of general obstacles: land slope, protected areas, and crossings and three line type obstacles: waterways, railroads, and highways.

In order to use this land obstacle data to help calculate optimal pipeline routes, the continuous obstacle data layer was rasterized into 1km by 1km cells. If there were no transportation obstacles contained within a given 1 km^2 cell, then the construction costs of a pipeline traversing the cell was assumed to be "1". From this base case construction cost, relative weights were then assigned to each obstacle in Table 8-2 according to the difficulty of traversing the obstacle. These relative weights were then added to the base case construction cost to form a combined pipeline construction cost factor.

Table 8-2 Estimated Relative Construction Cost Factor

Construction Condition		Cost Factor
Base Case		1
Slope		
	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area		
	Populated Area	15
	Wetland	15
	National Park	30
	State Park	15
Crossing		
	Wateway Crossing	10
	Railroad Crossing	3
	Highway Crossing	3

Note: The relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base case construction cost for an 8 inch pipeline.

[19] The populated places data is from US Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

The total pipeline construction cost factor for a cell is then the sum of the base case cost factor and the cost factors of all of the obstacles that exist in that cell. For example, the relative cost of a 8 inch pipeline crossing a river in the national park would be 41: 1 (base case) + 30 (national park) + 10 (river crossing). Using the weighted cost layer calculated above, the spatial analysis function in ArcGIS was used to determine the least cost pipeline path for connecting each source and sink.

8.3.4 Pipeline Transport Cost Estimation

The model decomposes the pipeline construction cost into two components: the basic pipeline construction cost (diameter-dependent) and the additional obstacle cost (diameter-independent). The basic pipeline construction cost is estimated to be $12,000/in/km[20]. The additional obstacle cost was calculated as the product of the relative weight assigned in Table 8-2 and the basic construction cost of an 8 inch pipeline[21]. The additional obstacle cost does not vary with the pipeline diameter, since the amount of site preparation required for pipeline construction does not vary according to pipeline size. The cumulative pipeline construction cost was then calculated as the sum of the basic construction cost and the additional obstacle cost.

For pipeline operations the pipeline O&M cost were estimated to be $3,100/km per year, regardless of pipeline diameter (Heddle, *et.al.*, 2003). A capital charge of 0.15 was used to annualize the construction cost over the operating life of the pipeline so that the annual pipeline transportation was 0.15 of its construction cost plus the annual O&M cost.

8.4 Source-Sink Matching Methodology

The source-sink matching methodology approximates the optimal source-sink allocation among a set of CO_2 sources and CO_2 sinks within a defined study area. For this analysis, each CO_2 source will be linked to a least cost geological sink based on a least-cost transportation route and an estimated injection cost. The linking algorithm also considers reservoir storage capacity and ensures that each linked sink had sufficient storage capacity for all sources matched with it.

The list of geographical sinks used in the matching analysis includes hydrocarbon fields with EOR potential, hydrocarbon fields without EOR potential, saline aquifers, and coalbeds. While all of these sinks are suitable for sequestration, the cost of sequestration varies for each sink type. The sinks can be grouped into two basic categories: (1) oil fields with EOR potential that are eligible for oil production credits, and (2) non-EOR hydrocarbon fields, saline aquifers and coal beds that will have to bear the full cost for CO_2 transportation, compression, and injection. Projects are assumed to have 25 year lifetime, and sources are only matched up to a sink if the sink's remaining storage capacity exceed the source's 25-year CO_2 flow.

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[20] Heddle et al., (2003) estimate that the average pipeline construction cost (including obstacle crossing cost) is $20,989/in/km. For sparsely populated areas average pipeline construction costs are estimated to be $12,400/in/km.

[21] For a 100km 8 inch pipeline with 6 waterway crossings, 1 railroad crossing, 1 highway crossing, and pass 1 km wetland. The estimated construction cost is ($12,000/in/km)*(8 in)*(100km) (base case construction) + $960,000*6 (waterway crossing) + $288,000 (railroad crossing) + $288,000 (highway crossing) + $1,440,000 (wetland crossing) = $17,376,000, which is similar to the average number provided by Heddle: ($20,989/in/km)*(8in)*(100km) = $16,791,200.

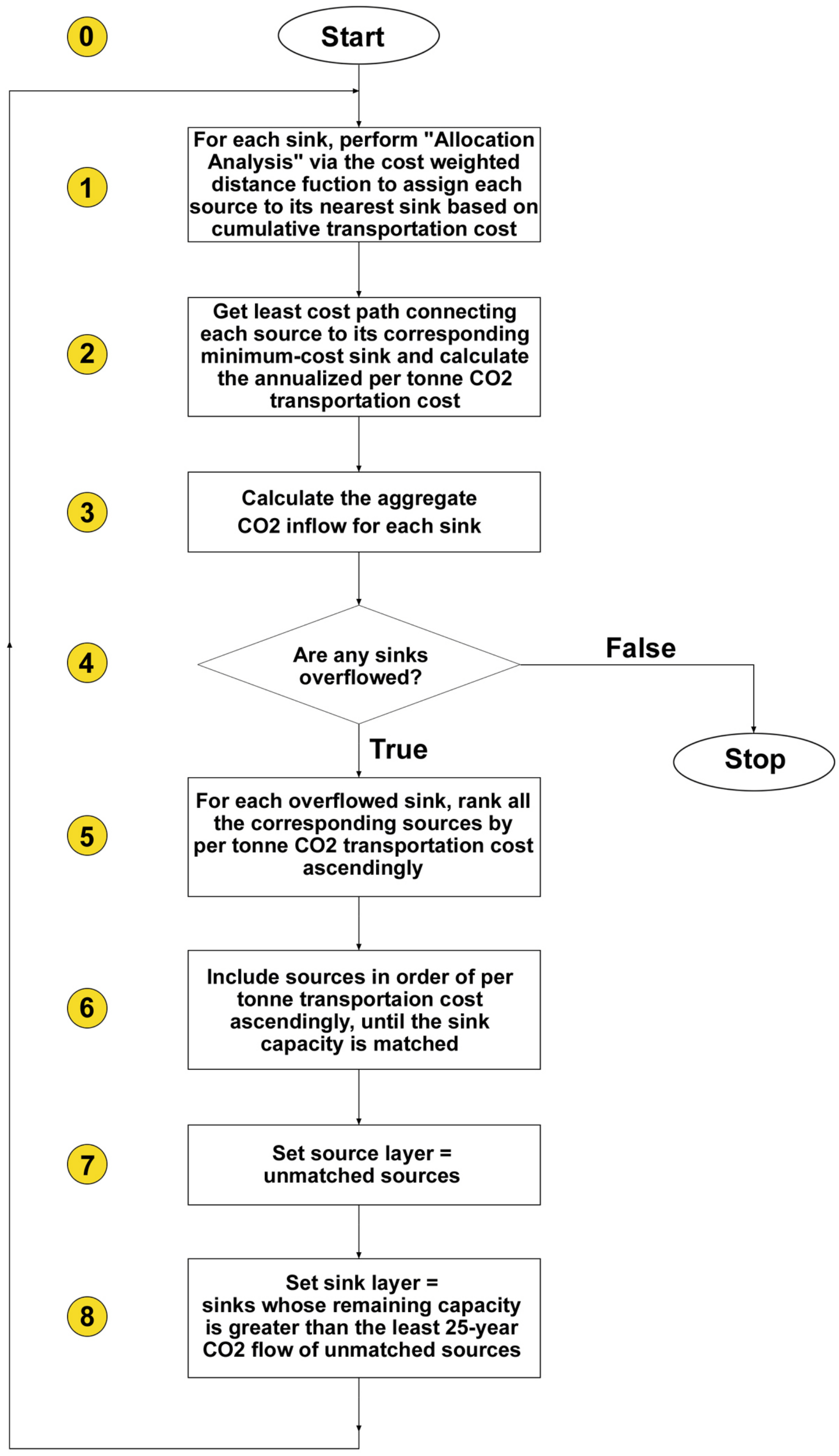
The linking analysis is conducted in two stages: first considering cheaper sinks before proceeding to sinks with higher storage costs. In the first iteration only EOR sites are included as potential sinks, since they would purchase CO_2 from a provider. After allocating the EOR storage capacity to the appropriate sources, the matching algorithm is rerun with non-EOR sinks included in the list of potential sinks. One caution is that sources that matched to EOR sinks but with transportation cost over EOR credit value[22] should enter in the analyses of both stages since the saving in transportation cost when matched to non-EOR sinks may overweigh the additional injection cost plus the loss of EOR credit. Therefore, a final check is also run to compare total cost calculations of both options for these sources to decide which one represents the true least cost matching.

8.4.1 Matching to EOR Sinks

In first stage all the CO_2 sources considered in the analysis are set as the source layer, while only the oil fields with EOR potential are included as potential sinks. An iterative algorithm is developed to "optimize" the source-sink matching using the ArcGIS *"spatial analysis tool."* Figure 8-2depicts the flow chart for this iterative matching algorithm using an example of matching process at this stage when only transportation cost needs are considered:

[22] EOR credit value is assumed as \$16/t of CO_2 in the study.

Figure 8-2 Flow Chart of the Least-cost Path CO_2 Source-Sink Matching Algorithm

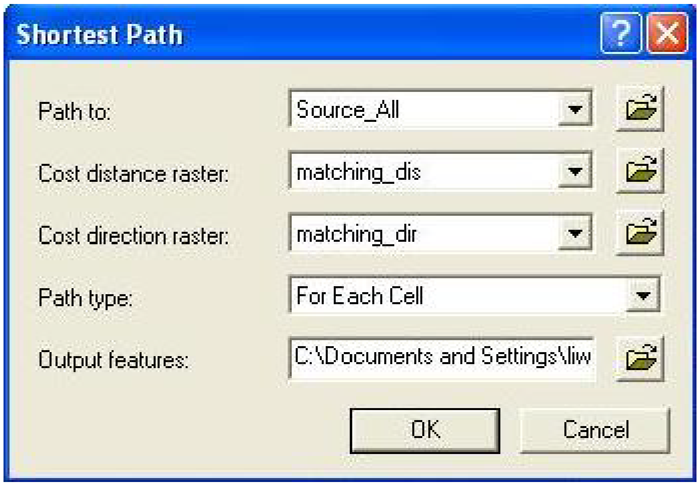


- At the first step, the *"Allocation Analysis"* function is used to assign each source to its nearest sink based on the transportation cost (Figure 8-3). The allocation result provides a picture of how the sources would be optimally linked to the sinks within the region if there were no restriction on the storage capacity of each sink.

Figure 8-3 Cost Weighted Allocation Analysis Interface in Step 1

- In the second step, the *"Least Cost Path"* function was used to get the least cost path linking each source to its corresponding least-cost sink (Figure 8-4). Using the transportation cost estimation algorithm discussed in a previous report on CO_2 pipeline transportation, the capital cost and maintenance cost are calculated as the cost per tonne of CO_2 transported.

Figure 8-4 Least Cost Path Analysis Interface in Step 2



- In the third step, the 25-year CO_2 flow volumes from all sources assigned to each sink in step 1 are summed up to get the aggregate 25-year CO_2 flow.

- In step 4, the aggregate 25-year CO_2 flow calculated in step 3 is compared to the estimated CO_2 storage capacity for each sink.
    - If none of the sinks is over capacity, then the iteration ends with an approximately “optimal” matching outcome.
    - If some of the sinks are over capacity, the program continues to step 5 to evaluate which sources should be excluded from the “overfilled” sinks.

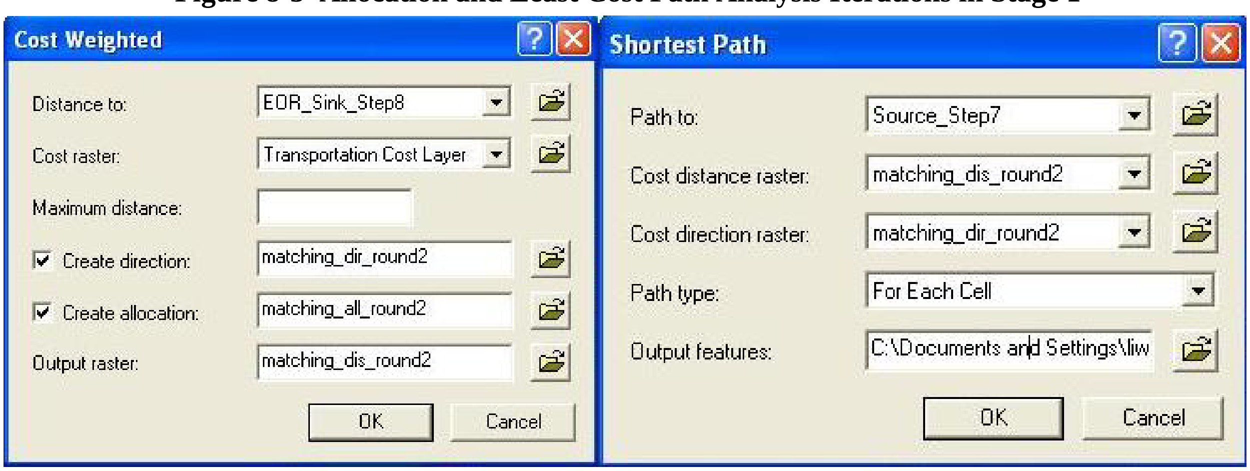
- In step 5, for each “overfilled” sink, the associated sources are ranked in ascending order by the transportation cost per tonne of CO_2.

- In step 6, the ordered sources for each “overfilled” sink are re-added to the sink’s “matched source set” in ascending order of CO_2 transportation cost. Sources are added until the sink’s remaining storage capacity is less than the 25-year CO_2 flow of the smallest source assigned to this sink in step 1 that have not been added to the “matched source set.”

- In step 7, all of the sources that are not included in “matched source set” for any sinks are set as the new “source layer”.

- In step 8, all sinks with remaining CO_2 storage capacity exceeding the 25-year CO_2 flow of the smallest source in the new “source layer” defined in step 7 are set as the new “sink layer”. The program then goes back to step 1 and reruns the source-sink matching algorithm until all sources are matched and no sink is “overfilled” or there is not any sink whose remaining storage capacity is more than the 25-year CO_2 flow of the smallest unmatched source (Figure 8-5).

Figure 8-5 Allocation and Least Cost Path Analysis Iterations in Stage 1



While the matching algorithm described above was capable of determining a near optimal solution, the algorithm might not find the absolute least cost solution. Since the algorithm did not evaluate whether assigning one source to a relatively more costly sink could reduce overall system cost, the optimization was not truly optimal. Even though the matching algorithm used in this analysis was not “truly optimal,” this is a typical problem in system optimization and the algorithm produces a reasonable result. The complexity of a “true” system optimization algorithm was beyond the scope of the Phase I analysis, but efforts in Phase II will focus on improving the algorithm functionality.

8.4.2 Matching to Non-EOR Sinks

- After allocating the EOR storage capacity to the appropriate sources, the matching algorithm would be rerun with the oil and gas fields without EOR potential and saline aquifers included in the list of potential sinks if there were still unmatched CO_2 sources. The sources that matched to EOR sinks but with transportation cost over EOR credit value should also enter in this stage to compare the total cost of alternative options.

- The iterative algorithm used in this stage is similar as that in first stage (Figure 8-6). However, In addition to transportation and capacity constraints, sources were allocated while also considering the injection costs[23]. The differences exit in step 5 and 6. At this stage, for each “overfilled” sink, the associated sources are ranked in ascending order by the full costs of transportation and injection per tonne of CO_2.

Figure 8-6 Allocation and Least Cost Path Analysis Iterations in Stage 2

8.4.3 Integrated Results

In this analysis \$16/t of CO_2 was used as an assumed EOR credit value, meaning that a CO_2 source can receive \$16/t of CO_2 used for EOR. If the transportation cost from a CO_2 source to the matched EOR site was less than \$16/t at Stage I, then the CO_2 should be allocated to that EOR site with no doubts. Meanwhile, those unmatched CO_2 sources at Stage I should be allocated to the corresponding sinks at Stage II. However, if the transportation costs to the matched EOR site were greater than \$16/t at Stage I, then the CO_2 source should be double checked whether to link to the EOR sink or Non EOR sink depending on the total costs.

[23] The injection cost estimation was based on methods used by Heddle, et.al. (2003). The Heddle injection cost model requires inputs for surface injection pressure, downhole injection pressure, CO_2 flow rate, and reservoir properties.

For example, the model was applied to analyze the CO_2 source-sink matching in California. It yielded that EOR sites in California alone provides sufficient storage capacity to sequestrate CO_2 flows from major stationary CO_2 sources in the state. In the first stage, all of the 35 EOR sites with storage capacity over 20 Mt[24] can be connected to their corresponding EOR sinks. Except for four outliers, the transportation costs for all sources are below \$16/t CO_2, the assumed CO_2 EOR-injection credit. With no doubts, those CO_2 sources with transportation costs to EOR sites below \$16/t CO_2 should be connected to EOR sinks.

However, for the four outlier sources, a new round of source-sink matching was applied using the oil and gas fields without EOR potential and saline aquifers suitable for CO_2 storage in California as the sink layer instead. A final check was conducted to compare the full costs to decide whether they should be matched to EOR or non-EOR sinks. Table 8-3 presents the comparison results for these sources to connect to alternative sinks. Except for the source with transportation to EOR site of \$16.8/t CO_2 that remains to be connected to its EOR destination, the other three sources are reassigned to saline aquifers instead because of the lower full costs.

Table 8-3 Comparisons of Alternative Options for Sources with EOR Transportation over \$16/t CO_2 in California

Facility Name	Plant Type	25-year CO2 Flow (Mt)	Pipeline Diameter (inch)	to EOR Sink		Alternative Option		
				Transportation Cost (\$/t)	EOR Credit (\$/t)	Destination	Transportation Cost (\$/t)	Injection Cost (\$/t)
Delta Energy Center, LLC	POWER PLANT	5.43	6	30.75	16.00	Aquifer	0.00	1.95
Sutter Energy Center	POWER PLANT	3.97	6	65.30	16.00	Aquifer	0.00	2.66
TXI Riverside Cement	CEMENT	1.91	8	72.13	16.00	Aquifer	6.22	5.54
California Portland Cement	CEMENT	11.84	8	16.82	16.00	Aquifer	15.16	0.89

After all the CO_2 sources were linked to their corresponding sinks, the full sequestration cost could be estimated for each source. For sources matched with EOR sites the full cost estimate included costs for capture, transportation, and an EOR credit. For sources matched with oil and gas fields without EOR potential or saline aquifers, the full cost estimate included capture cost, transportation cost, and injection cost. The specific sequestration cost could sometimes even be negative for specific ammonia and gas processing plants with low transportation costs since their capture cost was less than the assumed EOR credit.

[24] Most of the CO_2 sources will emit more than 20 Mt CO_2 over the 25-year project lifetime.

9 Annex 9: CO_2 Source-Sink Matching Algorithm

9.1 Introduction

This annex documents the CO_2 source-sink (many sources to many sinks) matching algorithm. Based on the previous work on CO_2 pipeline transport and injection cost model, this annex further explores the source-sink allocation to generate a fully integrated, optimal carbon capture and sequestration network that minimizes the full mitigation cost for the network system subject to constraints of the sinks' storage capacity.

The analysis uses a two-step approach:

1) Identify candidate least-cost pipeline network between all sources and sinks. Each source in the system can connect to any of the sinks.
2) Optimize the source-sink allocation through the pipeline network for the give set of CO_2 sources and sinks that minimizes the full mitigation cost.

In this annex:

- Section 9.2 presents the methodology to identify candidate least-cost pipeline network between all sources and sinks.
- Section 9.3 discusses the optimization model used to minimize full mitigation cost.
- Section 9.4 briefly summarizes the methods to estimate the three components of the mitigation cost, including capture, transport and injection costs.
- Section 9.5presents the case study conducted in the State of California.
- Appendix 9-A includes the GAMS programming codes used for the CO_2 source-sink (many sources to many sinks) matching analysis.

9.2 Pipeline Network

CO_2 sources and geological sinks may be widely spatially dispersed on the regional scale and need to be connected through a CO_2 pipeline network. Pipeline construction costs vary considerably according to the local terrain and are also affected by the presence of buildings or infrastructure. Pipeline construction is more expensive in hilly areas than on flat plains. In order to reduce complications and costs, a pipeline's route should avoid passing through populated places[25], wetlands, and national or state parks. In order to account for such obstacles in the study, the locations and characteristics of these obstacles were loaded into Geographic Information System (GIS) software. Using the GIS software the costs for traversing such obstacles during pipeline construction were combined into a single obstacle data layer. This obstacle layer reflected three types of general obstacles: land slope, protected areas, and crossings and three line type obstacles: waterways, railroads, and highways.

The obstacle layer can be used to reverse-engineering the contribution (weight) of geographical features to the cost of pipeline construction. In order to use this land obstacle data to help

[25] The populated places data is from US Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

identify optimal pipeline routes, the continuous obstacle data layer was rasterized into 1km by 1km cells. If there were no transportation obstacles contained within a given 1 km^2 cell, then the construction costs of a pipeline traversing the cell was assumed to be "1". From this base case construction cost, relative weights were then assigned to each obstacle in Table 9-1 according to the difficulty of traversing the obstacle. These relative weights were then added to the base case construction cost to form a combined pipeline construction cost factor. The total pipeline construction cost factor for a cell is then the sum of the base case cost factor and the cost factors of all of the obstacles that exist in that cell.

Based on the combined pipeline construction cost factor (cost surface), it is possible to identify the lowest-cost paths for direct pipelines between all possible pairs of CO_2 sources and sinks. We used the MIT CO_2 pipeline transport cost tool that was developed in a GIS system to identify the least-cost path and calculate its length for linking each source to sink. The MIT CO_2 pipeline transport cost tool makes two assumptions: 1) Pipeline paths depend only on the geography feature of the obstacles; 2) The diameter (determined by mass flow rate) does not affect the pipeline path. The second assumption is not always true. A larger pipeline might choose a different path than a smaller pipeline. However, the difference is small based on our previous study and we believe it is reasonable to assume pre-optimized network.

Table 9-1: Estimated Relative Construction Cost Factor

Construction Condition		Cost Factor
Base Case		1
Slope		
	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area		
	Populated Area	15
	Wetland	15
	National Park	30
	State Park	15
Crossing		
	Wateway Crossing	10
	Railroad Crossing	3
	Highway Crossing	3

Note: The relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base case construction cost for an 8 inch pipeline.

After the lowest-cost paths for direct pipelines between all possible pairs of CO_2 sources and sinks are identified, the next question is to decide which routes to go for all the sources. It can be solved as an optimization problem using a non linear programming (NLP) model.

9.3 Optimization Model

The second step of the source-sink matching analysis is to optimize the source-sink allocation through the pipeline network for the give set of CO_2 sources and sinks that minimizes the full mitigation cost. The primary objective is to *minimize* the total mitigation cost, including capture, transport and injection costs, subject to the constraints of the sinks' storage capacity. It can be solved by a general NLP optimizer. We used the General Algebraic Modeling System (GAMS) optimization software package, a high-level modeling system for mathematical programming and optimization.

The model formulation, like any NLP problem, consists of an objective function (minimize full mitigation costs) and a set of constraints that have to be satisfied.

Minimize

$$\sum_i Capture\_\cos t(i) + \sum_i \sum_j Transport\_\cos t(i,j) + \sum_j Inejction\_\cos t(j)$$

S.T.

$$\sum_j flow(i,j) = capture\_\ factor \times emission(i) \quad \forall i$$
$$\sum_i flow(i,j) \le storage\_capacity(j) / project\_years \quad \forall j$$

Because the storage capacity of geologic sinks is given as a maximum total volume rather than as an annual limit, we have to convert it to an annual injection limit by assuming a project life time (25 years in this study).

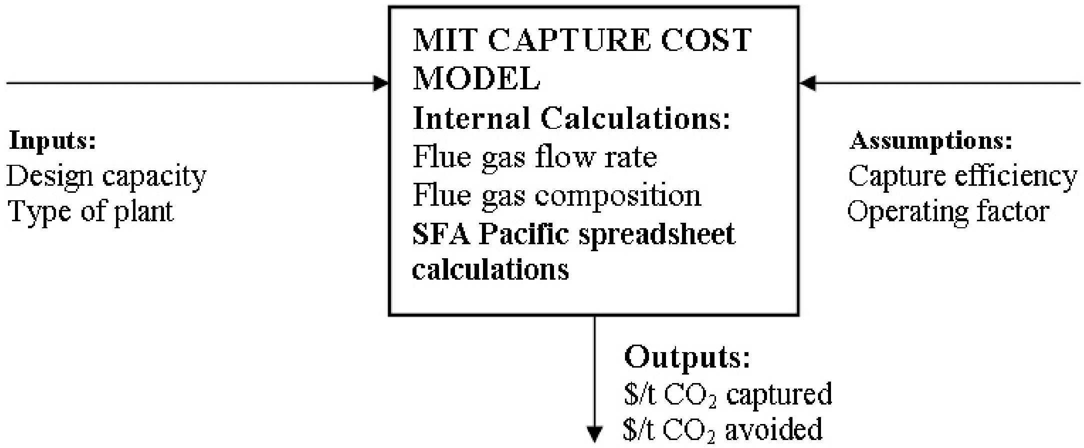
9.4 Mitigation Costs

The section briefly discusses the cost estimation methods for capture, transport and injection.

9.4.1 CO_2 Capture Cost

The study uses the "*Generic CO_2 Capture Retrofit*" spreadsheet prepared by *SFA Pacific, Inc*. as the basis for calculating the CO_2 capture cost for stationary CO_2 sources. These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour); (2) the flue gas composition (volume share or weight share of CO_2 in flue gas); and (3) the annual load factor.

Figure 9-1 Capture Cost Model



In order to use the SFA Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made *that power plants would operate at 80% of their designed capacity once the capture facility has been installed.* So for each fuel type the CO_2 capture cost only varies based on the plant's design capacity. The fossil power plants were grouped into three categories by fuel type: coal-fired, gas-fired, and oil-fired. The study only analyzed power plants with a design capacity greater than 100MWe.

Two key input variables needed to estimate the CO_2 capture cost for the fossil fuel power plants are the flue gas flow rate and the flue gas composition. Since this specific information was unavailable for all of the power facilities, two further assumptions were used to derive reasonable values for these variables. The two flue gas assumptions were that: (*1) the flue gas flow increases linearly with the design capacity of a power plant; (2) within each fuel-type category, the flue gas composition is independent of the design capacity.* Table 9-2 provides the flue gas flow rate and composition used in the data for each type of fossil fuel power plant.

Table 9-2 Flue Gas Flow Rate and Composition for Coal-, Gas-, and Oil-Fired Power Plants

		Coal-fired PP	Gas-fired PP	Oil-fired PP[1]
Flow Rate (mt/h per 100MW design capacity)		4.06	5.14	4.6
Flue Gas Composition (% in Volume)				
	N_2	73.81%	75.86%	74.84%
	CO_2	15.15%	4.18%	9.67%
	H_2O	8.33%	8.18%	8.26%
	O_2	2.54%	11.77%	7.16%
	misc	0.16%	0.00%	0.08%

Note: [1]Data about oil-fired power plants are MIT Carbon Capture and Sequestration Technologies Program estimates. Others are from SFA, Pacific "*Generic CO2 Capture Retrofit*"and *"Existing Coal Power Plant CO2 Migration*"spreadsheets.

The capture cost estimation tool from SFA Pacific, Inc. was also adapted so that it could be used with the non-power sources. The flue gas composition information was only available for the following four facility types: ammonia plants, cement plants, gas processing facilities, and refineries. As a result the analysis was limited to estimating the capture cost for the four facility types listed.

Table 9-3 Assumed CO_2 Emission Factor, Flue Gas Component and Load Factor for Non-power CO_2 Sources

Facility Type	CO2 Emission Factor	Flue Gas Component (volume)	Annual Load Factor
Ammonia	1.13t CO_2/t Ammonia	100% CO_2	100%
Cement	0.75t CO_2/t Clinker	25% CO_2, 75%N_2	100%
Gas Processing	608t CO_2/mmcfd	100% CO_2	100%
Refineries	9.9t CO_2/BPD	10% CO_2, 90% N_2	100%

Table 9-3 lists the assumed CO_2 emission rates per unit of primary product production, the flue gas composition, and the annual load factor used for each of the four types of non-power CO_2 sources evaluated. The actual flue gas flow rates were unknown, but they were estimated based on plant capacity, the CO_2 emissions factor, and the flue gas composition.

Using data derived from the SFA Pacific capture cost estimation tool, we plotted the CO_2 capture cost as functions of the plant design capacity for each plant type (and fuel type for power plants). The relationship between CO_2 capture and avoidance costs and the design capacity of the coal-fired power plant can be represented by the following two power functions (with R^2 close to 1) (Figure 9-2).

Figure 9-2 Estimated CO_2 Capture and Avoidance Costs for Coal-fired Power Plants

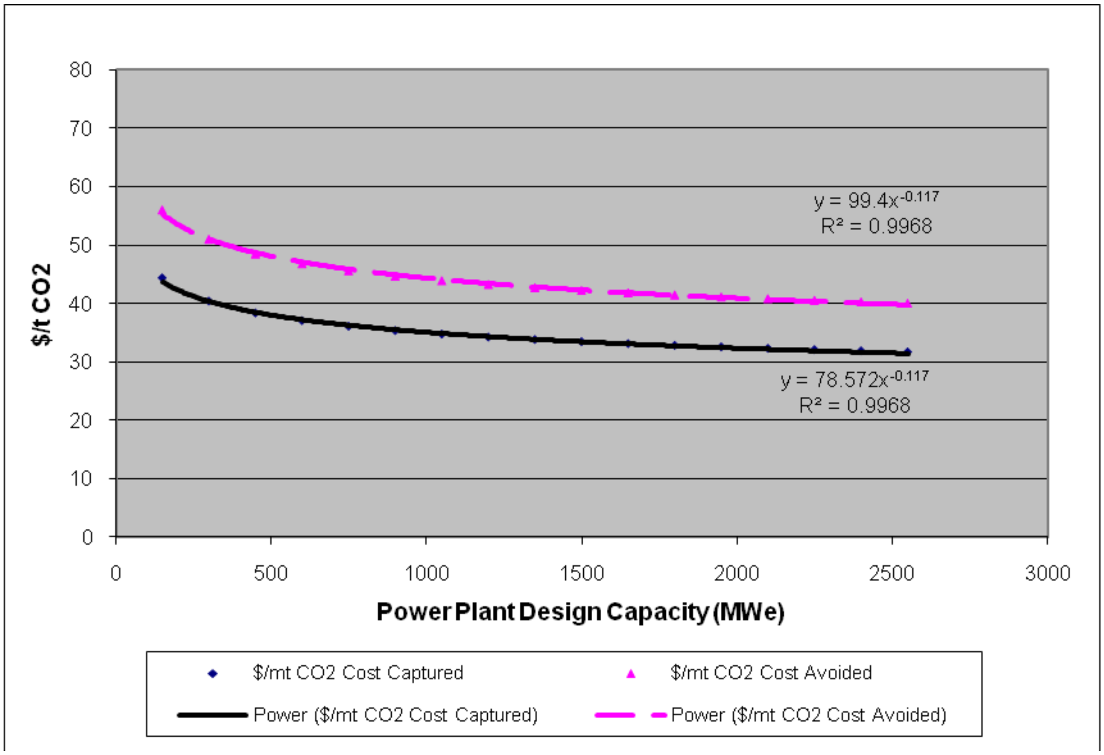


Table 9-4 summarizes the estimated formula for CO_2 capture costs as functions of power plant design capacity for each plant type category.

Table 9-4 Formula of per tonne CO_2 Capture Cost

Category	**Coal-Fired PP**	**Gas-Fired PP**	**Oil-Fired PP**
Capacity Unit	**MW**	**MW**	**MW**
$/t CO2 Captured Formula	$78.57x^{-0.1168}$	$144.87x^{-0.1564}$	$93.34\ x^{-0.1295}$

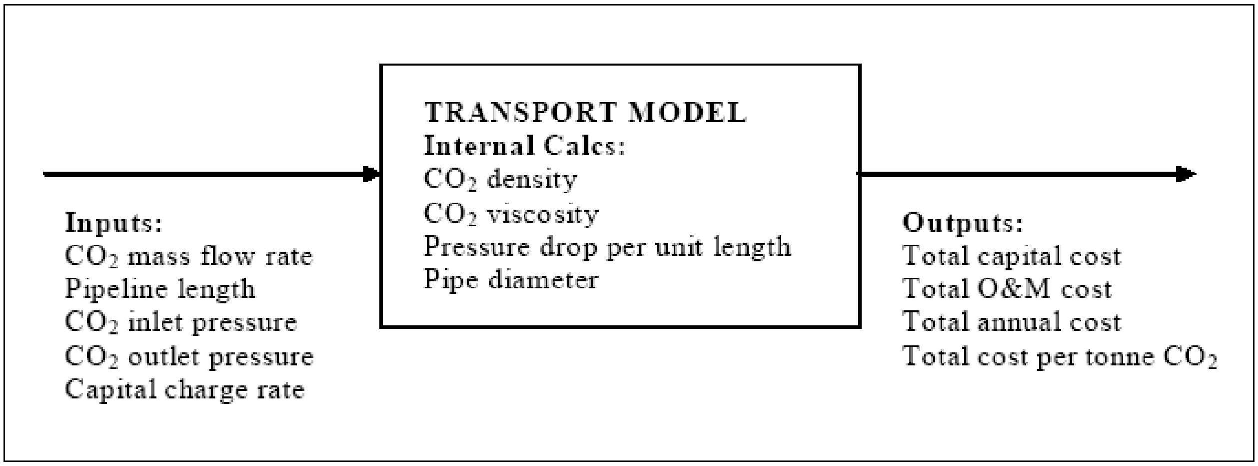
Category	**Ammonia**	**Cement**	**Gas Processing**	**Refineries**
Capacity Unit	kt/yr	kt/yr	MMCFD	BPD/yr
$/t CO2 Captured Formula	$22.425x^{-0.0871}$	$86.37x^{-0.1244}$	$28.48x^{-0.1165}$	$224.32x^{-0.1432}$

Capture cost = ($/t CO_2 captured) * flow rate

9.4.2 Transport Cost

Figure 9-3 gives an overview of the transportation cost model. The model can be broken down into two steps, the module to calculate the pipeline diameter as a function of maximum CO_2 flow rate and the economic module to calculate the total and annualized CO2 pipeline transport cost.

Figure 9-3 Pipeline Transport Overview Diagram



Pipeline Diameter Calculation

The pipeline design capacity is one of the first design criteria needed for CO_2 transport cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transport requirements of their corresponding CO_2 emissions sources. Therefore, the study calculates the pipeline diameter as a function of pressure drop allowance per unit length, friction, CO_2 density and CO_2 mass flow rate.

Equation (1) gives the relationship among pipeline diameter (*D*), maximum allowable pressure drop (• *P/*• *L*), CO_2 mass flow rate ($\dot{m}$), CO_2 density (•), and the Fanning friction pressure (*f*) can be characterized by the following formula (Heddle *et.al.*, 2003):

$$\frac{\Delta P}{\Delta L} = \frac{32 f \dot{m}^2}{\pi^2 \rho D^5} \tag{1}$$

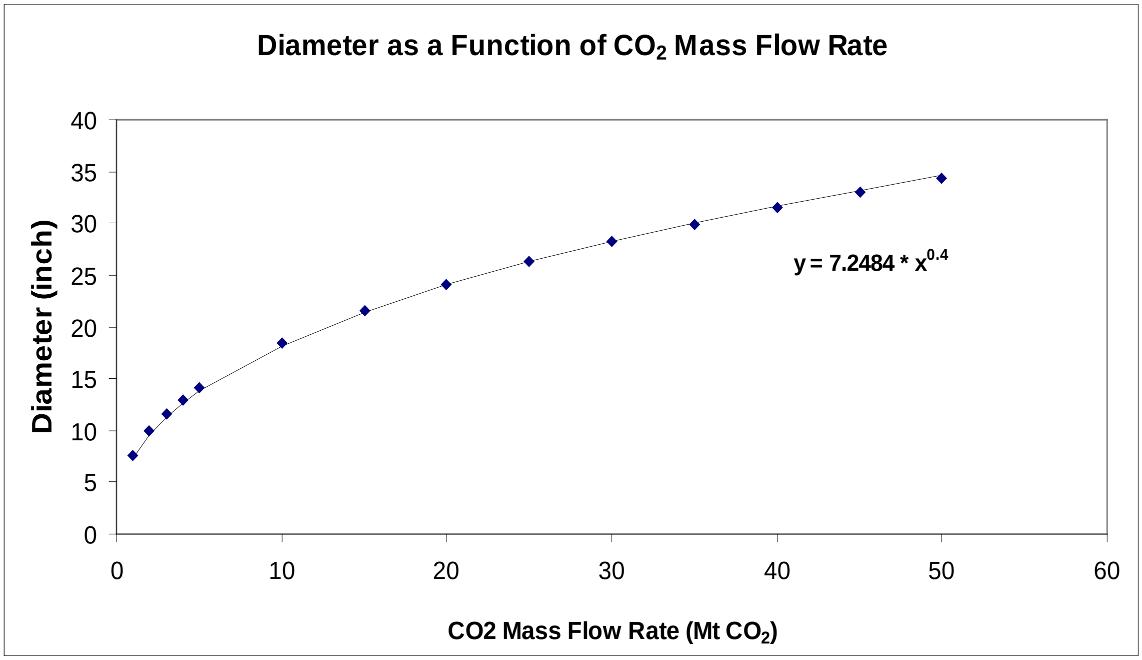
In equation (1), the default maximum allowable pressure drop per unit length (• *P/*• *L*) is set to be 49Pa/m. The default CO_2 density (•) is assumed to be 884 kg/m^3[26]. calculated from MIT CO_2 property calculator, The Fanning friction pressure is found by using the relationship based on the Moody chart (see Heddle *et.al.*, 2003).

Figure 9-4 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. Based on the power function in Figure 9-4, for any given maximum CO_2 flow rate, the module can determine the appropriate pipeline diameter. Due to the continuous function requirements of the NLP optimization model, it is assumed in this study that the pipelines that will be used for CO_2 transportation are not limited to the standard type gas industry pipelines.

[26] According to the MIT CO2 property calculator, the CO2 density of 884 kg/m^3 corresponds to the status of a temperature of 25 ºC and a pressure of 158 bar.

The calculation is found to be consistent with most literatures on pipeline diameter design (Vandeginste and Piessens, 2008). At this stage we did not consider elevation difference and pumping station.

Figure 9-4 Pipeline Diameter as a Function of Maximum Mass CO_2 Flow Rate



Pipeline Total Cost

The amount of cost data on CO_2 pipelines in the open literature is very limited. But there is an abundance of cost data for natural gas pipelines. For this reason, land construction cost data for natural gas pipelines were used to estimate the construction costs for CO_2 pipelines. This should be adequate for the screening study as there is little difference between land construction costs for these two types of pipelines. It is worth noting, however, that CO_2 pipelines might be slightly more expensive because of the greater wall thickness needed to contain CO_2, which is transported at higher pressures.

The CO_2 transport model divides the pipeline transport cost into two components: the land construction cost and the O&M cost. Equation (2) gives the formula to annualize the land construction cost over the operating life of the pipeline:

$$\text{Annualized Cost} = \text{Land Construction Cost} * \text{Capital Charge Factor} + \text{O\&M Cost} \quad (2)$$

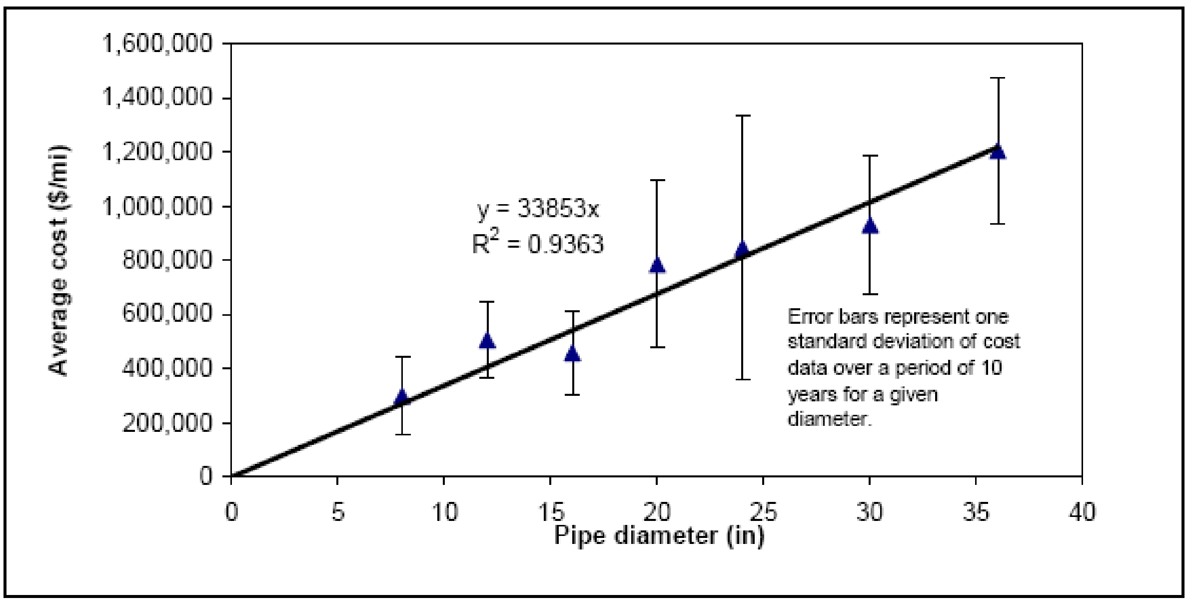
The package uses a default capital charge of 0.15 and assumes the pipeline O&M cost to be $5,000/mile per year, independent of pipeline diameter (Heddle, *et.al.*, 2003). Our previous study adopted two correlations to estimate the land construction costs for CO_2 pipelines: the MIT correlation and the CMU correlation. We used the MIUT correlation in this study.

The MIT correlation was developed by the Carbon Capture and Sequestration Technologies Program (CCSTP) at the Massachusetts Institute of Technology. It assumes that the CO_2 pipeline land construction cost has a linear correlation with pipeline diameter and length. Using data for natural gas pipelines consists of cost estimates filed with the United States' Federal Energy Regulatory Commission (FERC) and reported in the Oil and Gas Journal between 1989 and 1998, Heddle *et.al.* (2003) estimate the CO_2 pipeline construction cost to be \$33,900/in/mile. Figure 9-5 shows the regression analysis of pipeline land construction cost data. Equation (3) provides the formula for the MIT correlation used in the transport package:

$$LCC = \alpha * D * L \tag{3}$$

where α = \$33,853;
D: pipeline diameter in inches (function of CO_2 flow rate);
L: least-cost pipeline route length in miles;

Figure 9-5 Regression Analysis of Pipeline Land Construction Cost Data



Due to increased costs and inflation, the land construction costs of pipeline construction have increased since the original LCC was calculated (based on data between 1989 and 1998). New data from the Oil and Gas Journal shows the costs of pipeline construction up to 2007.

These new values were used in order to obtain a more accurate, up to date number. The equation is the same; it is just calculated by an Index.

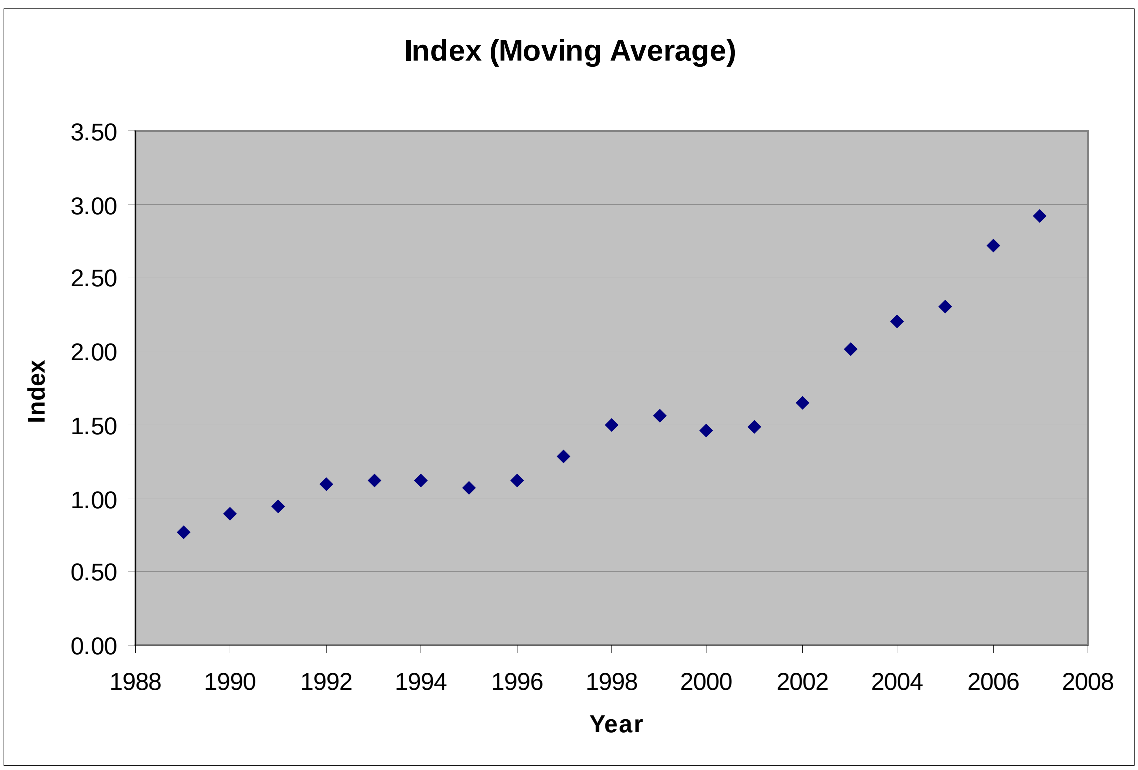
$$LCC = \bullet * D * L * Index_t \tag{4}$$

The new Index for year 2007 equals to 2.92. See Table 9-5 and Figure 9-6. This value is an optional addition when calculating the LCC for post 2007.

Table 9-5 Price Index for MIT Correlation

Year	Index	Running Average
1989	0.83	0.83
1990	0.71	0.90
1991	1.15	0.95
1992	0.98	1.10
1993	1.17	1.12
1994	1.20	1.12
1995	1.00	1.07
1996	1.02	1.12
1997	1.34	1.28
1998	1.48	1.51
1999	1.69	1.56
2000	1.51	1.47
2001	1.20	1.48
2002	1.74	1.65
2003	2.00	2.01
2004	2.30	2.20
2005	2.31	2.30
2006	2.30	2.71
2007	3.53	2.92

Figure 9-6 Price Index (Running Average) for MIT Correlation



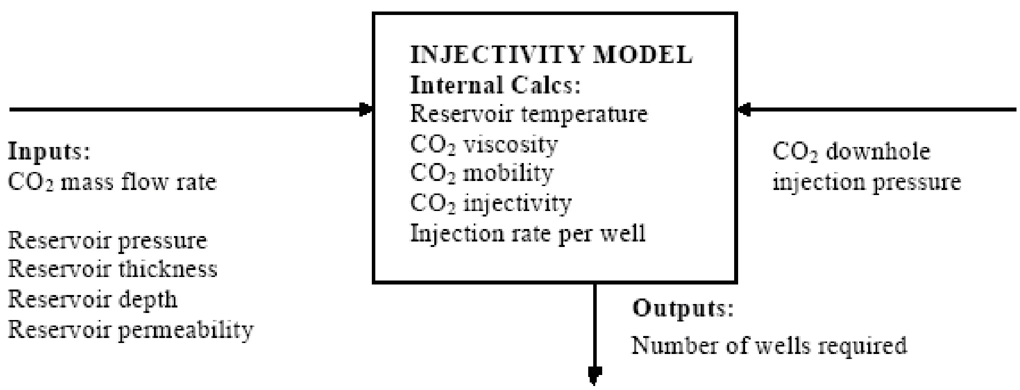
9.4.3 Injection Cost

The cost estimation modeling for the geologic CO_2 storage options can be broken down into two components: CO_2 injectivity model and storage cost model. Our previous study adopted two different methods in developing the CO_2 injectivity model: Law & Bachu method and ARI method. This study used the Law & Bachu method for estimating injectivity.

Injectivity Model

The Law & Bachu method in developing the CO_2 injectivity model is based on the basic relationship for calculating CO_2 injectivity, downholde injection pressure, and the number of wells required for a given CO_2 flow rate derived by Law and Bachu (1996). It requires inputs for CO_2 mass flow rate, CO_2 downhole injection pressure, and reservoir pressure, thickness, depth and permeability. Figure 9-7 provides the overview of the model, which will be described below in greater detail.

Figure 9-7 Law & Bachu CO_2 Injectivity Model Overview



Given the depth of the reservoir, the downhole injection pressure (dinjprs) is assumed to be equal to the reservoir fracture pressure, which by default is set to be dinjprs (psi) = 0.6*depth (feet).

Step 1: Viscosity Calculation

The viscosity of the CO_2 (visct) at the reservoir conditions is calculated using correlations from V. V. Altunin (1975) that assumes the CO_2 viscosity is a function of the pressure and temperature of the reservoir[27]. In case the reservoir temperature is not given, we estimate the reservoir temperature assuming a surface temperature of 15ºC and a geothermal gradient of 25 ºC /km. In case the reservoir pressure (rsvrprs) is not given, it is by default set to the hydrostatic pressure by the following formula:

[27] The CO_2 viscosity was calculated using a computer code (CO_2 Property Calculator) developed by Victor Malkovsky of the Institute of Geology of Ore Deposits, Petrography, Mineralogy and Geochemistry (IGEM) of the Russian Academy of Sciences, Moscow. We converted his FORTRAN code into Visual Basic.

rsvrprs (psi) = 0.435*depth (feet).

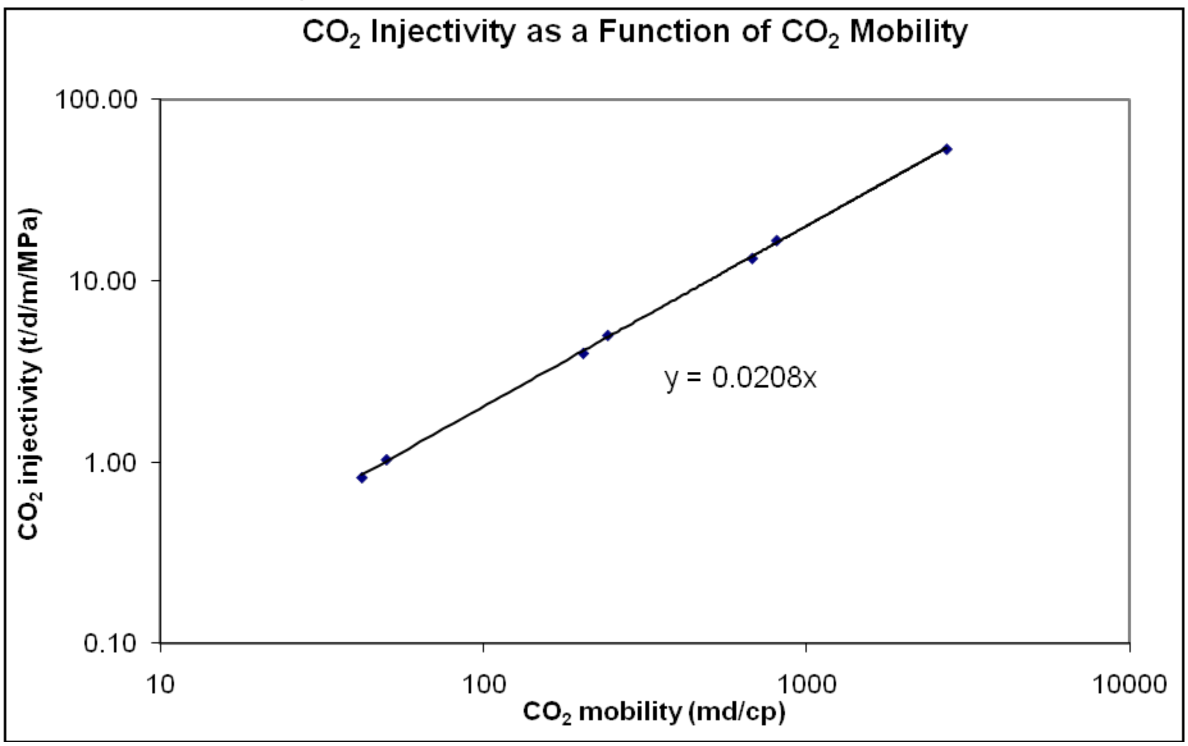
Step 2: Absolute Permeability Calculation
Next, the absolute permeability is found from (Law and Bachu, 1996)

absperm = $(perm_h \times perm_v)^{0.5}$

where absperm = absolute permeability (mD)
$perm_v$ = the vertical permeability and is equal to 0.3 times the horizontal permeability (mD)
$perm_h$ = the given horizontal permeability (mD)

Step 3: Injectivity Calculation
A relationship, derived by Law and Bachu (1996), is used to determine CO_2 injectivity from CO_2 mobility. This relationship is shown in Figure 9-8.

Figure 9-8 CO_2 Injectivity as a Function of CO_2 Mobility



The equation for CO_2 injectivity is

injectivity=0.0208*mobility

mobility= absperm/visct

where injectivity = the mass flow rate of CO_2 that can be injected per unit of reservoir thickness (thickness) and per unit of downhole pressure difference (dinjprs – rsvrprs) (t/d/m/MPa)

mobility = CO_2 mobility (mD/cp)

Step 4: Well Number Calculation

Given the CO_2 injectivity, the CO_2 injection rate per well (injtd) and then the number of well required for a given CO_2 flow rate (numwell) could be found from:

numwell = CO_2flow / injtd

Injtd = injectivity x thickness x (dinjprs – rsvrprs)

where numwell = number of wells required for a given CO_2 flow rate

CO_2flow = given CO_2 flow rate (tonne/day)

injtd = CO_2 injection rate per well (tonne/day)

thickness= reservoir thickness (m)

dinjprs = downhole injection pressure (MPa)

rsvrprs = initial reservoir pressure (MPa)

Injection Cost Model

The injection cost model consists of two types of costs, each with several components. The costs are classified as either capital or annual costs. Capital costs include: site evaluation and screening; drilling; and injection equipment. Annual costs include ongoing operating and maintenance costs for the injection wells. This cost model builds and extends from the original injection cost model proposed in *Heddle et al., 2003*.

The model was for the most part built on two main sources of information, which were the best available to us at the time: the 2004 AIP Joint Association Survey on Drilling Costs, and the 2005 EIA Costs and Indices (see references for full details). In addition, we have applied costing methodology from ARI Basin Studies reports in this model.

Table 9-6 Injection Cost Components

Parameter	Unit	Value	Source
Capital costs			
Site Characterisation	\$/site	1,685,000	*Smith et al., 2001*
Drilling	\$/well	$0.204e^{0.0007 \times depth}$	*JAS 2004 data (vertical wells only)*
Lease Equipment	\$/well	9,277 + 48 × depth	*ARI "Basin Studies for EOR, Permian Basin" report*
Annual costs			
O&M	\$/well	20,720 + 25.61 × depth	*ARI "Basin Studies for EOR, Permian Basin" report*

Note:
Depth: in meters.

A capital charge of 0.15 was used to annualize the capital cost over the operating life of the injection so that the annual injection cost was 0.15 of its capital cost plus the annual O&M cost.

9.5 California Case Study

The source-sink matching methodology approximates the optimal source-sink allocation among a set of CO_2 sources and CO_2 sinks within a defined study area. This section presents a case study of matching sources and sinks based on least total cost in the State of California.

This analysis was conducted using the biggest 30 stationary CO_2 sources located in California which included power plants, cement plants and refineries. The project lifetime was assumed to be 25 years. Total source CO_2 flow over 25 years was about 1.4 Gt. Table 9-7 shows the CO_2 flow rate by source type.

Table 9-7 CO2 Flow Rate by Plant Types in California

Plant Type	Number of Plants	25-year CO2 Flow (Mt)
Power Plant	18	877
Cement Plant	4	161
Refinery	8	338
All sources	30	1,376

The list of geographical sinks used in the matching analysis includes hydrocarbon fields with EOR potential, hydrocarbon fields without EOR potential and saline aquifers. While all of these sinks are suitable for sequestration, the cost of sequestration varies for each sink type. The sinks can be grouped into two basic categories: (1) oil fields with EOR potential that are eligible for oil production credits, and (2) non-EOR hydrocarbon fields and saline aquifers that will have to bear the full cost for CO_2 transportation, compression, and injection. Projects are assumed to have 25 year lifetime, and sources are only matched up to a sink if the sink's remaining storage capacity exceed the source's 25-year CO_2 flow. The study used the biggest 6 oil fields with EOR potential and 8 non-EOR oil and gas fields (Table 9-8). We were unable to estimate the storage capacity for the 2 saline aquifers included in the study but we assumed the capacity was unlimited.

Table 9-8 Geological Sink Storage Capacity by Sink Type in California

Sink Type	Number of Sinks	Storage Capacity (Mt)
Oil Field with EOR	6	1,166
Other Oil and Gas Field	8	1,246
Saline Aquifer	2	n.a.
All sinks	16	n.a.

The total CO_2 storage capacity for oil fields with EOR potential included in the analysis was 1.2 Gt. Since the total 25 yr CO_2 flow rate from all sources was 1.4 Gt, some oil and gas fields without EOR potential or saline aquifers might be connected as potential sinks.

Figure 9-9 CO_2 sources and Geological Sinks included in the Study

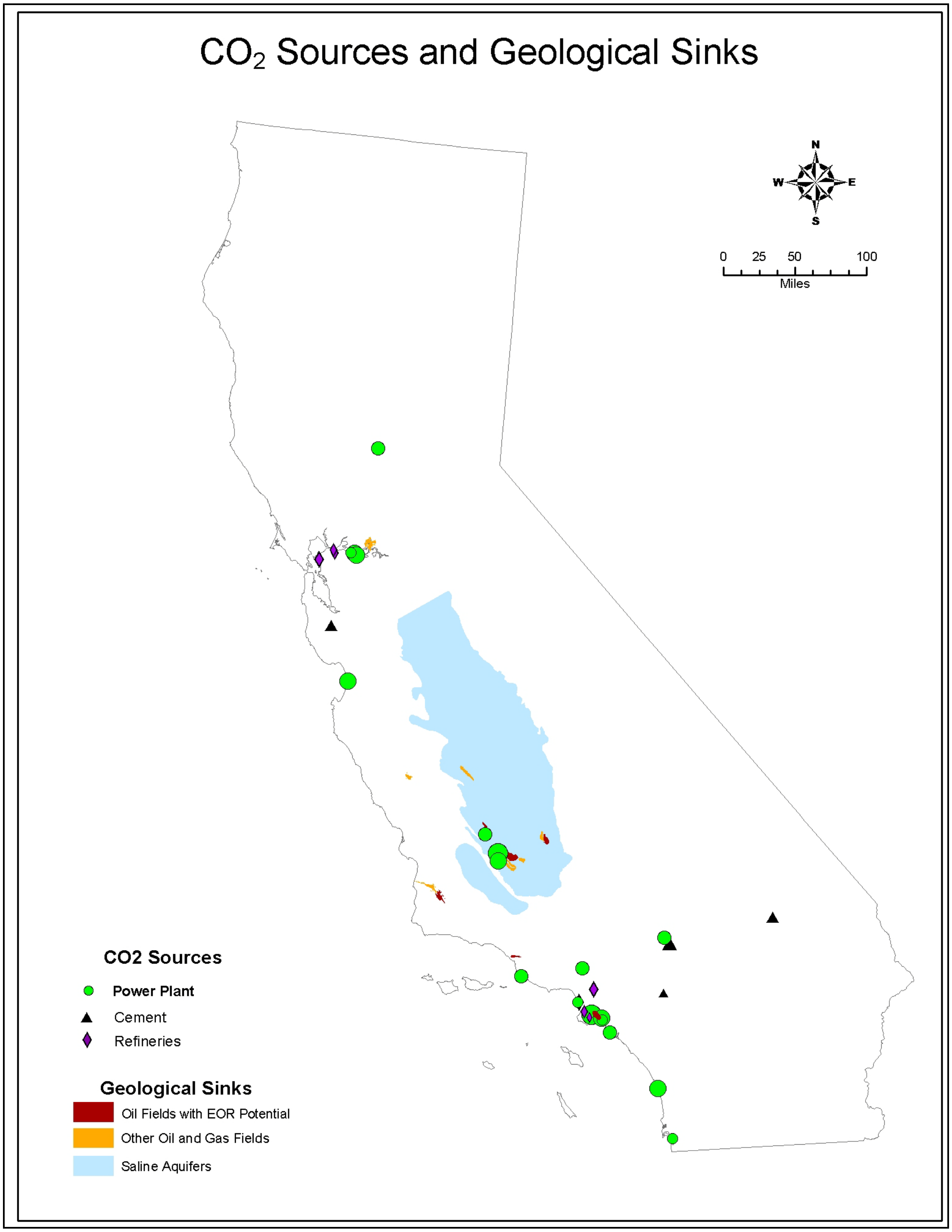
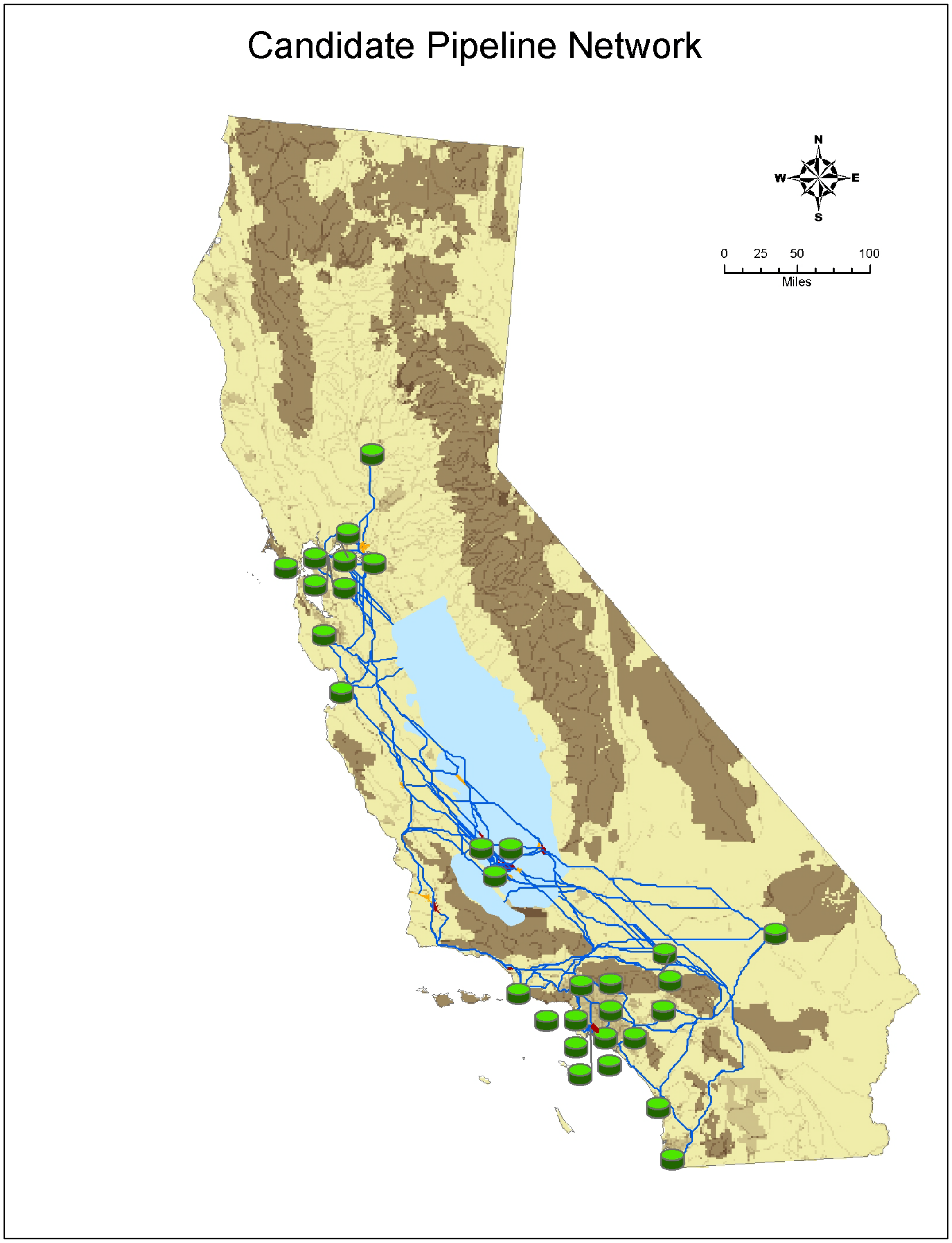


Figure 9-9 shows all the CO_2 sources, geological sinks used in the least-cost source-sink analysis in California. Candidate pipeline network was identified by using the MIT CO_2 pipeline transport and cost tool. In the network, potential pipeline routes (blue) connect the 30 biggest CO_2 sources (green) and 14 largest sinks (Figure 9-10).

Figure 9-10 Candidate Pipeline Network in California



We conducted the analysis for four scenarios:

- 2007 Transport Cost Base, assuming no EOR (the year 2007 cost index was applied to the transport cost. All the oil and gas fields were assumed to be without EOR potential so that no one was eligible for oil production credits.)

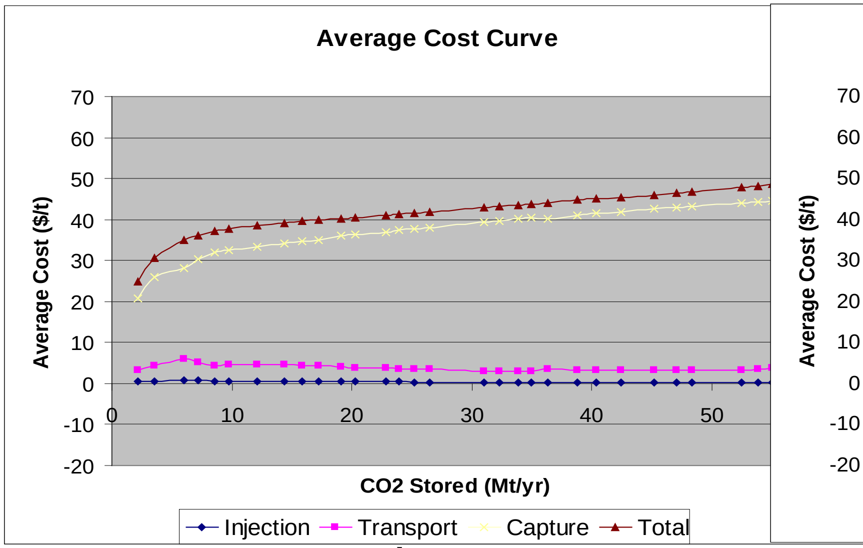
- 2007 Transport Cost Base, with EOR (the year 2007 cost index was applied to the transport cost. Oil production credit was assumed to be \$16/t CO_2.)
- MIT Transport Cost correlation, assuming no EOR (the MIT correlation was used directly to the transport cost. All the oil and gas fields were assumed to be without EOR potential so that no one was eligible for oil production credits.)
- MIT Transport Cost correlation, with EOR (the MIT correlation was used directly to the transport cost. Oil production credit was assumed to be \$16/t CO_2.)

Figure 9-11 presents the result of the analysis for the scenario of "2007 Transport Cost Base, with EOR". The chosen pipeline network (blue) connects 30 biggest CO_2 sources (green) and largest sinks (EOR and oil/gas fields, aquifers) that minimizes the full mitigation cost.

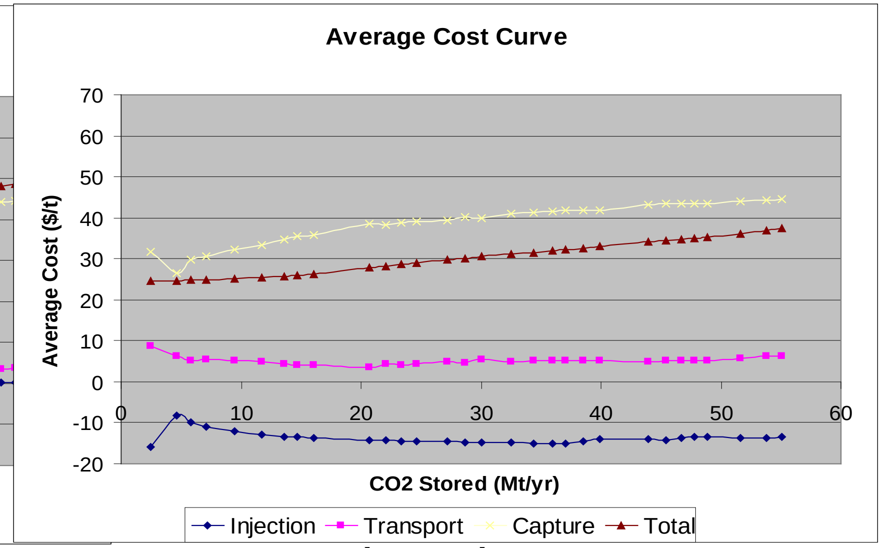
Figure 9-12 and Figure 9-13 plot the average cost curve and marginal mitigation cost by annual CO_2 storage rate for the four scenarios. Figure 9-14 plots the marginal transportation distance by annual CO_2 storage rate for the four scenarios.

Figure 9-11 Source-Sink Matching Result for "2007 Transport Cost Base, with EOR"

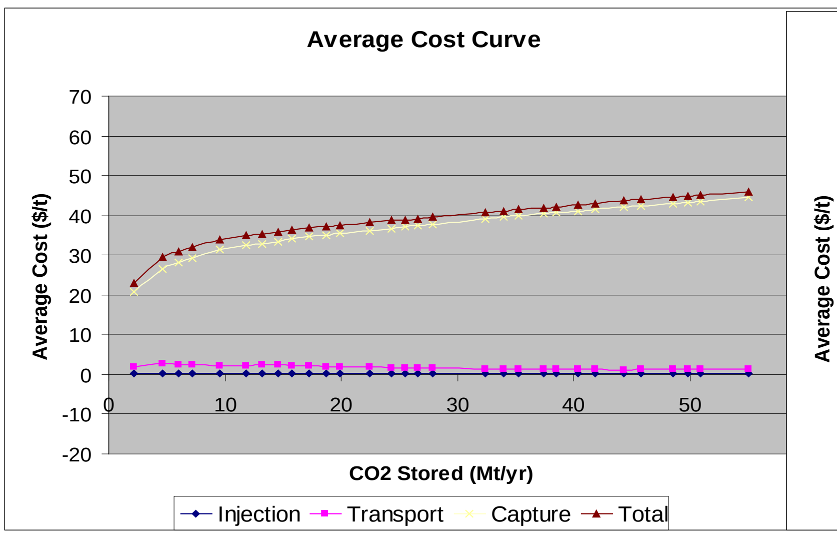
Figure 9-12 Average Cost Curve and Marginal Mitigation Cost by Annual CO_2 Storage Rate



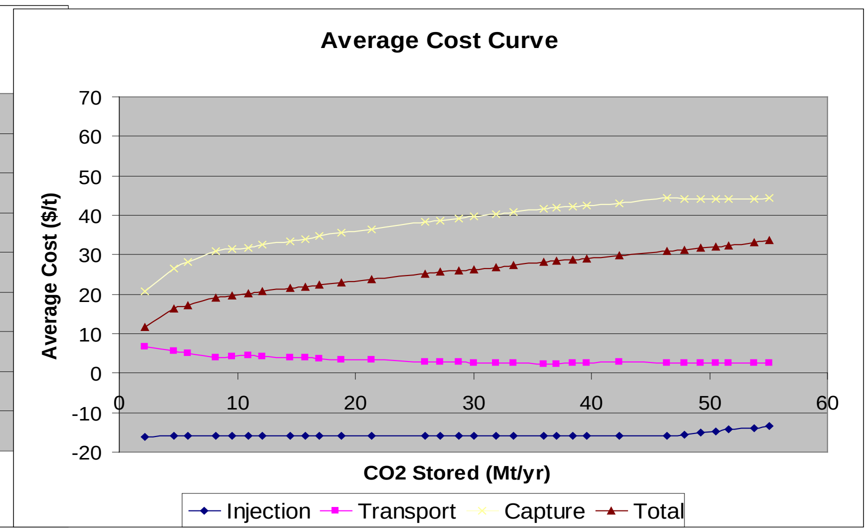
2007 Cost base: no EOR



2007 Cost base: with EOR

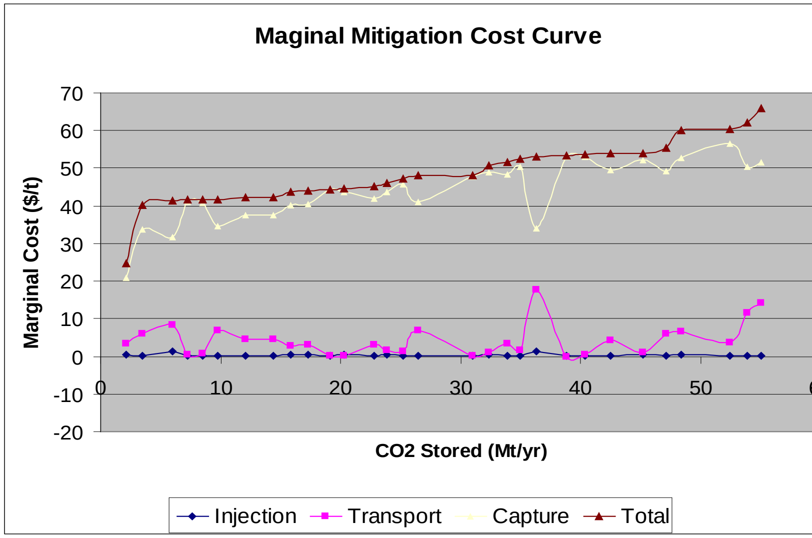


MIT cost correlation: no EOR

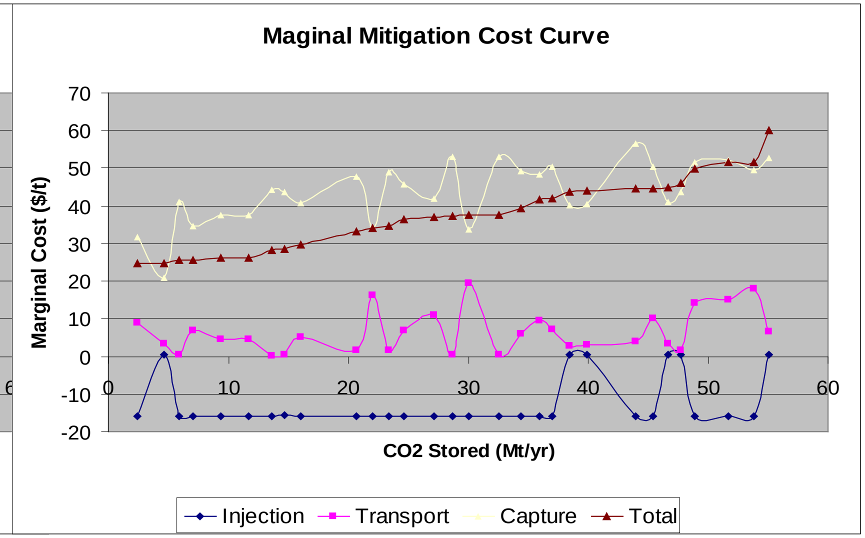


MIT cost correlation: with EOR

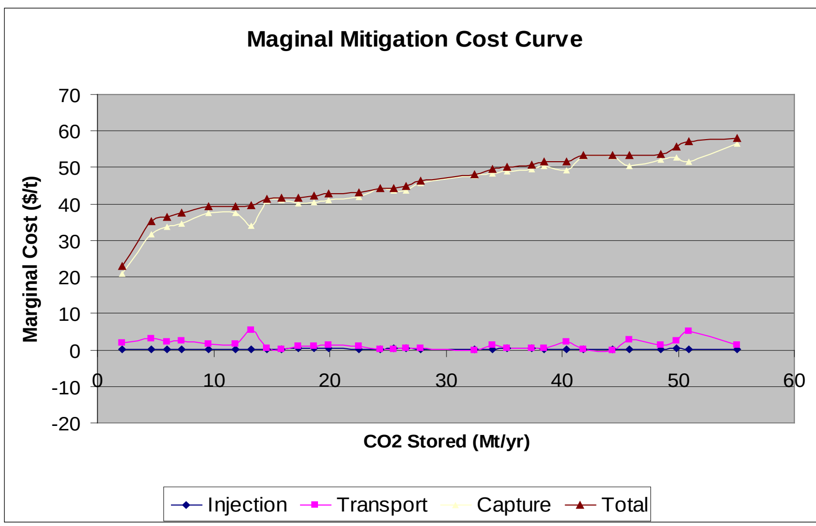
Figure 9-13 Marginal Cost Curve and Marginal Mitigation Cost by Annual CO_2 Storage Rate



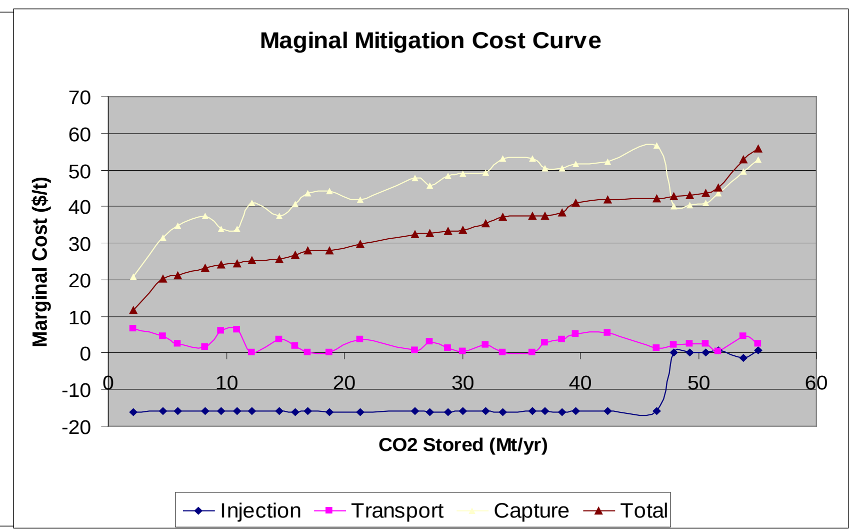
2007 Cost base: no EOR



2007 Cost base: with EOR

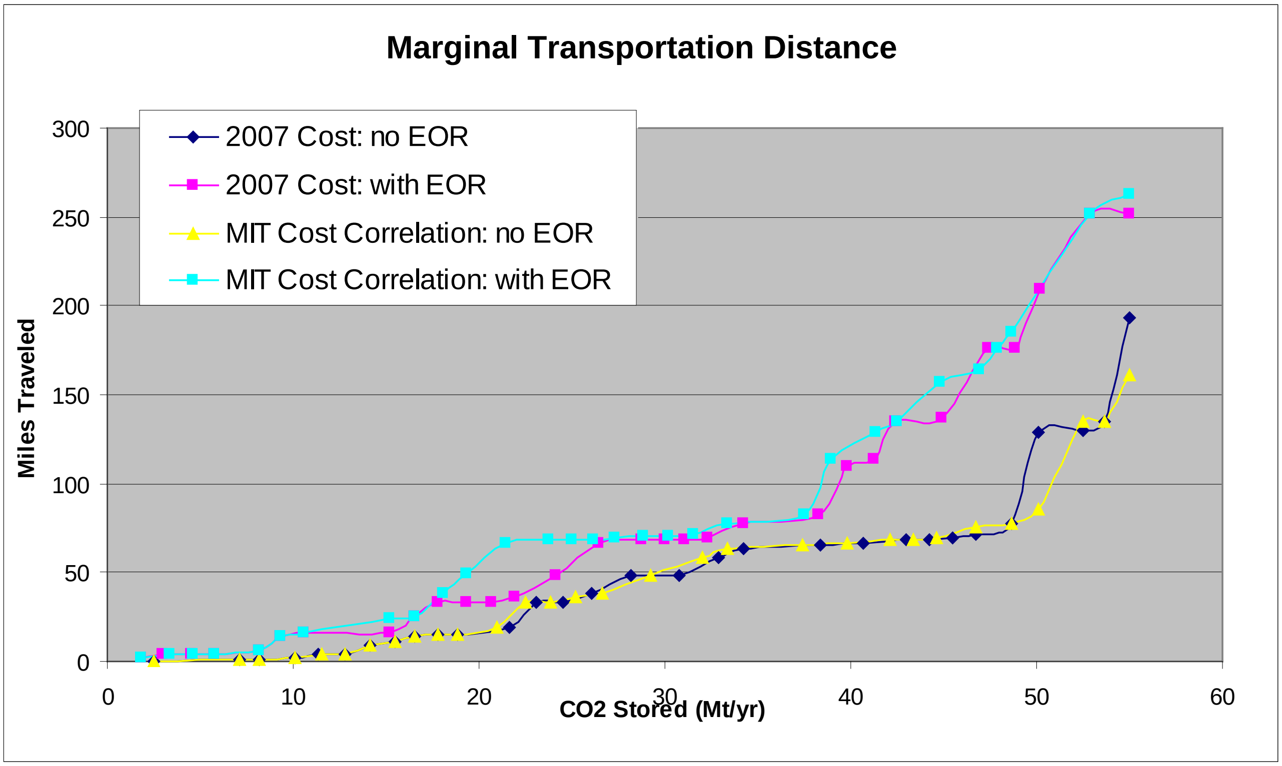


2007 Cost base: no EOR



2007 Cost base: with EOR

Figure 9-14 Marginal Transportation Distance by Annual CO_2 Storage Rate



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9.6 Appendix 9-A

/* MIT GAMS codes for the CO_2 source-sink (many sources to many sinks) matching analysis.*/

```
sets
      plant_type /gas, cement, refinery/
```

```
	i	sources	/i1 * i30/
	j	sinks	/j1 * j16/
	i_map(*,*) a tuple mapping from plant ID to type   /
$ondelim
$include source_type.csv
$offdelim
/;
	j_map(*,*) a tuple mapping from sink ID to type   /
$ondelim
$include sink_type.csv
$offdelim
/;
$onecho > Taskin_source.txt
par=capacity rng=c2 Rdim=1
par=emission rng=e2 Rdim=1
$offecho
$call gdxxrw.exe source_aug15.xls @Taskin_source.txt
$gdxin source_aug15.gdx

parameters
	capacity(i)
	emission(i)

$load capacity emission
$gdxin
*totoal emission from plant i, kt

$onecho > Taskin_sink.txt
par=perm_h rng=l2 Rdim=1
par=perm_v rng=n2 Rdim=1
par=visc rng=p2 Rdim=1
par=thickness rng=j2 Rdim=1
par=depth rng=d2 Rdim=1
par=rsvrprs rng=r2 Rdim=1
par=dinjprs rng=t2 Rdim=1
par=storage_cap rng=b2 Rdim=1
$offecho
$call gdxxrw.exe sink_aug15.xls @Taskin_sink.txt
$gdxin sink_aug15.gdx

	perm_h(j)
	perm_v(j)
	visc(j)
	thickness(j)
	depth(j)
	rsvrprs(j)
	dinjprs(j)
	storage_cap(j);
*storage capacity for sink j
$load perm_h perm_v visc thickness depth rsvrprs dinjprs storage_cap
$gdxin
;

table length(i,j)
$ondelim
$include route_aug15_m.csv
```

```
$offdelim
display length;

Scalars
        capital_charge /0.15/
        a_capture_gas  /144.87/
        b_capture_gas  /-0.1564/
        a_capture_cement  /86.37/
        b_capture_cement  /-0.1244/
        a_capture_refinery  /224.32/
        b_capture_refinery  /-0.1432/
        construction_per_inch_mile    /33853/
        transport_om_per_mile      /5000/
        a_diameter_flow    /7.2484/
        b_diameter_flow    /0.4/
        capture_factor /0.9/
        fixed_site_cost /1.685/
        fudge_factor /0.00001/
        a_drilling_depth /204000/
        b_drilling_depth /0.0007/
        a_equipment_depth /9277/
        b_equipment_depth  /48/
        a_inje_om_depth /20720/
        b_inje_om_depth  /25.61/
        injectivity_factor /0.0208/
        days_year /365/
        project_years  /25/
        eor_credit /-16.0/;

equations
        obj_func
        total_cost_source_eq(i)
        capture_cost_eq(i)
        capture_cost_gas_eq(i)
        capture_cost_cement_eq(i)
        capture_cost_refinery_eq(i)
        transport_cost_eq(i,j)
        diameter_eq(i,j)
        injection_cost_eq(j)
        site_char_cost_eq(j)
        drilling_cost_eq(j)
        equipment_cost_eq(j)
        injection_om_cost_eq(j)
        tot_inflow_eq(j)
        tot_inflow_storage_eq(j)
        tot_outflow_eq(i)
        tot_outflow_emi_eq(i)
        nwells_eq(j)
        tot_flow_eq
        tot_flow_control_eq

free variables
        obj
*unit:M$

Nonnegative variables
```

```
	flow(i,j)
*unit: Mt
;
flow.l(i,'j1') =  capture_factor * emission(i);
;
variables
	total_cost_source(i)
	capture_cost(i)
	capture_cost_gas(i)
	capture_cost_cement(i)
	capture_cost_refinery(i)
	transport_cost(i,j)
	diameter(i,j)
	site_char_cost(j)
	drilling_cost(j)
	equipment_cost(j)
	injection_om_cost(j)
	tot_inflow(j)
	tot_outflow(i)
	nwells(j)

	injection_cost(j)
	tot_flow
;
* table length(i,j) source-sink distance matrix from GIS

;

obj_func..                obj              =e=    sum(i, total_cost_source(i)) + sum(j, injection_cost(j));

total_cost_source_eq(i)..     total_cost_source(i)    =e=    capture_cost(i) + sum(j, transport_cost(i,j));

capture_cost_eq(i)..        capture_cost(i)        =e=    capture_cost_gas(i)$i_map(i,"gas") +
capture_cost_cement(i)$i_map(i,"cement")+  capture_cost_refinery(i)$i_map(i,"refinery");

capture_cost_gas_eq(i)..      capture_cost_gas(i)     =e=    a_capture_gas * [ capacity(i) ** b_capture_gas ] *
tot_outflow(i);

capture_cost_cement_eq(i)..    capture_cost_cement(i)  =e=    a_capture_cement * [ capacity(i) **
b_capture_cement ] * tot_outflow(i);

capture_cost_refinery_eq(i)..   capture_cost_refinery(i)=e=    a_capture_refinery * [ capacity(i) **
b_capture_refinery] * tot_outflow(i);

transport_cost_eq(i,j)..      transport_cost(i,j)     =e=    {construction_per_inch_mile *  diameter(i,j) *
capital_charge + transport_om_per_mile  } * length(i,j) * flow(i,j) / [flow(i,j)+ fudge_factor] / 1000000;

diameter_eq(i,j)..          diameter(i,j)          =e=    a_diameter_flow * { [ (flow(i,j)+  fudge_factor)   ] **
b_diameter_flow };

tot_outflow_eq(i)..         tot_outflow(i)         =e=    sum(j, flow(i,j));

tot_outflow_emi_eq(i)..       tot_outflow(i)         =e=    capture_factor * emission(i);

tot_flow_eq..               tot_flow              =e=    sum(i, tot_outflow(i));
```

```
tot_flow_control_eq..          tot_flow              =e=     capture_factor * sum(i, emission(i));

injection_cost_eq(j)..         injection_cost(j)       =e=     {[site_char_cost(j) + drilling_cost(j) + equipment_cost(j)] *
capital_charge  + injection_om_cost(j)}$j_map(j,"noneor") + [eor_credit * tot_inflow(j)]$j_map(j,"eor");

site_char_cost_eq(j)..         site_char_cost(j)       =e=     {fixed_site_cost * tot_inflow(j) / [tot_inflow(j) +
fudge_factor]};

drilling_cost_eq(j)..          drilling_cost(j)        =e=     {nwells(j) * a_drilling_depth * exp[ b_drilling_depth *
depth(j) ]  / 1000000 };

equipment_cost_eq(j)..         equipment_cost(j)       =e=     {nwells(j) * [a_equipment_depth + b_equipment_depth *
depth(j)]  / 1000000 };

injection_om_cost_eq(j)..      injection_om_cost(j)    =e=     {nwells(j) * (a_inje_om_depth + b_inje_om_depth *
depth(j))  / 1000000 };

nwells_eq(j)..                 nwells(j)               =e=     tot_inflow(j) * 1000000 / { [injectivity_factor * sqrt( perm_h(j) *
perm_v(j) ) / visc(j)] * thickness(j) * (dinjprs(j) - rsvrprs(j))* days_year };

tot_inflow_eq(j)..             tot_inflow(j)           =e=     sum(i, flow(i,j));

tot_inflow_storage_eq(j)..     tot_inflow(j)           =l=     storage_cap(j)/ project_years;


model ccs /all/;

*display capacity, perm_h,perm_v,visc,thickness,depth,rsvrprs,dinjprs,storage_cap;

Option NLP = CoinIpopt;

solve ccs using nlp minimizing obj;


display flow.l;

display obj.l;

display capture_cost.l, injection_cost.l, transport_cost.l, total_cost_source.l;
```