2. PROPOSED ACTION AND ALTERNATIVES

2.1 INTRODUCTION

This chapter describes in detail the Proposed Action, including alternative sites, the No-Action Alternative, and alternatives eliminated from further consideration. Section 2.2 includes an overview of the FutureGen Project to provide the context for information contained in the alternative site discussions. Additionally, Section 2.5 presents detailed technical information on the proposed FutureGen Project that forms the basis for the analyses in this Environmental Impact Statement (EIS). This information includes detailed descriptions of the proposed power plant, carbon dioxide (CO_2) capture and sequestration (storage) methods, monitoring activities, planned and potential research activities, resources required for the proposed project, and construction and operation plans. Lastly, future design, site characterization, and National Environmental Policy Act (NEPA) of 1969 activities are described.

2.2 DESCRIPTION OF THE PROPOSED ACTION

DOE proposes to provide financial assistance to the Alliance to plan, design, construct, and operate the FutureGen Project. DOE has identified four reasonable alternative sites and will determine which sites, if any, are acceptable to DOE to host the FutureGen Project. The four sites currently being considered as reasonable site alternatives for the FutureGen Project are:

- Mattoon, Illinois;
- Tuscola, Illinois;
- Jewett, Texas; and
- Odessa, Texas.

In a March 2004 Report to Congress, DOE estimated the cost of the project at $950 million in constant 2004 dollars shared at a 74/26 ratio by DOE and the Alliance. Accounting for escalation, based on representative industry indices, the project is currently estimated to cost $1,757,232,310 in as-spent dollars. Including $300,800,000 in expected revenues from the sale of electricity, which would be used to offset operational costs and research and development expenses, the total net project cost is estimated to be $1,456,432,310 in as-spent dollars. DOE will share approximately 74 percent of the net cost (estimated at $1,077,760,230), which includes at least $80 million in projected contributions from foreign governments. The Alliance will share approximately 26 percent of the net cost (estimated at $378,672,080). The cost estimate will be updated as work progresses.

The FutureGen Project would be a research facility as well as the cleanest coal-fueled power system in the world for co-producing electricity and hydrogen (H_2). The facility would incorporate cutting-edge research, as well as the development of promising new energy-related technologies at a commercial scale. Low carbon emissions would be achieved by integrating CO_2 capture and sequestration operations with the proposed power plant (see Figure 2-1). Performance and economic test results from the FutureGen Project would be shared among participants, industry, the environmental community, and the public.

Construction would begin in 2009, with initial startup of the facility anticipated in 2012. DOE-sponsored activities would include construction and 4 years of plant operation, testing, and research (including 1 year of startup) (i.e., research and development) followed by 2 years of additional geologic monitoring for the sequestered CO_2 (see Figure 2-2). After DOE-sponsored activities conclude, the Alliance or its successor would manage and operate the power plant. DOE expects the plant would operate for at least 20 to 30 years, and potentially up to 50 years.

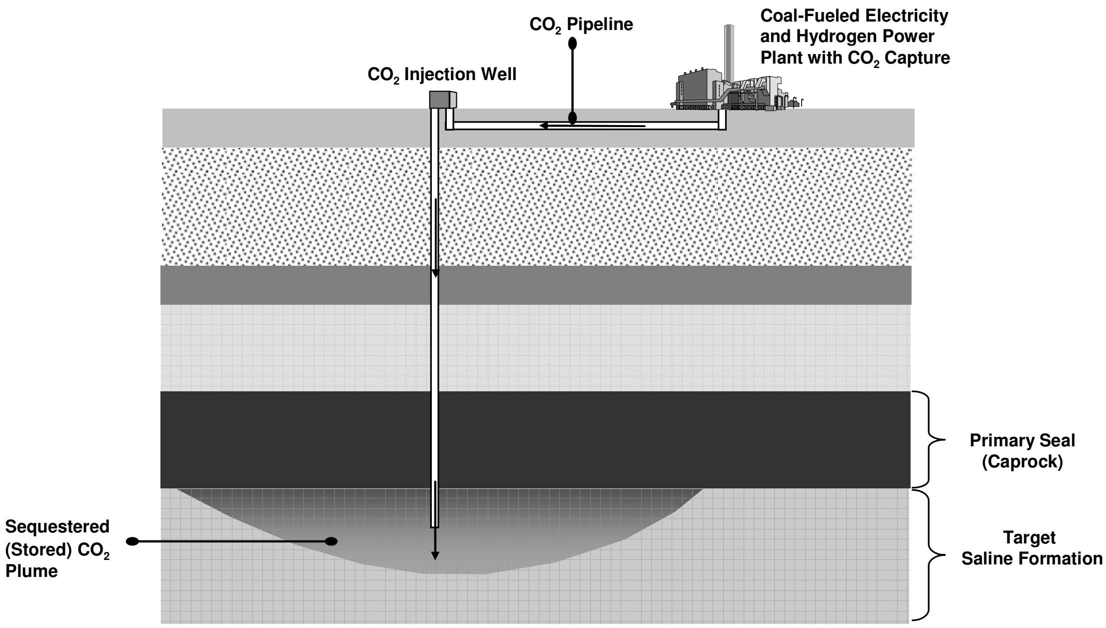


Figure 2-1. FutureGen Project Overview

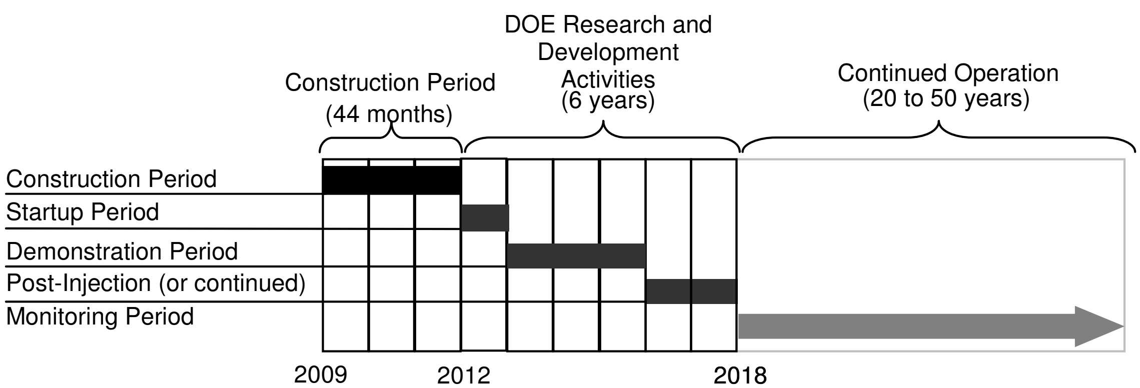


Figure 2-2. Construction, Demonstration, Monitoring, and Operating Schedule

The FutureGen Project would include a coal-fueled electric power and H_2 production plant. The power plant would be a 275-megawatt (MW) output Integrated Gasification Combined Cycle (IGCC) system. CO_2 capture and geologic storage would occur at a rate of at least 1.1 million tons (1 million metric tons [MMT]) of CO_2 per year. Major components needed to support the proposed FutureGen Project include:

- A power plant site and plant infrastructure;
- A sequestration site for CO_2 injection wells related infrastructure, and deep saline formation (i.e., the geologic formation where CO_2 would be stored);
- Utility connections and corridors (e.g., water supply, sanitary wastewater, electric transmission, natural gas pipelines, and CO_2 pipelines); and
- Transportation routes (rail and truck).

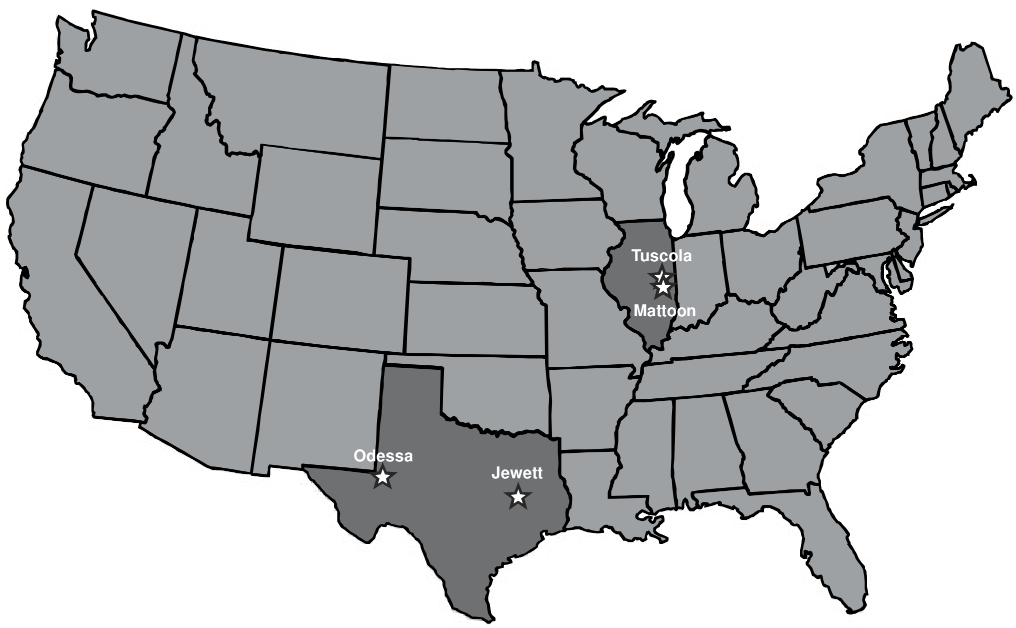
> **IGCC** refers to the combination (integration) of the gasification process with a combined-cycle power plant (i.e., a plant that uses both steam turbine and combustion turbine generators).

2.3 NO-ACTION ALTERNATIVE

Under the No-Action Alternative, DOE would not share in the cost for constructing and operating the FutureGen Project. Without DOE funding, the Alliance would not likely undertake the commercial-scale integration of CO_2 capture and geologic sequestration with a coal-fueled power plant in a comparable timeframe. Therefore, the No-Action Alternative is considered a “No-Build” Alternative.

2.4 SITE ALTERNATIVES

There are four alternative site locations under consideration for the FutureGen Project (see Figure 2-3). These candidate sites were identified by the Alliance through a rigorous screening and selection process. DOE reviewed the Alliance’s decision-making process and findings to ensure that all reasonable alternatives were considered for analysis in this EIS. Alternatives considered but determined to be unreasonable are discussed in Section 2.4.***6***.



Source: FG Alliance, 2006a

Figure 2-3. Alternative Site Locations

2.4.1 MATTOON SITE

Proposed Mattoon Power Plant and Sequestration Site

The proposed Mattoon Site consists of approximately 444 acres (180 hectares) of farmland located approximately 1 mile (1.6 kilometers) northwest of the City of Mattoon, in Coles County, Illinois. Key features of the Mattoon Site are listed in Table 2-1. The proposed power plant and sequestration site would be located on the same parcel of land. The proposed site is bordered to the northeast by State Route (SR) 121 and a Canadian National Railroad. Potable water would be supplied by extending existing lines from Mattoon's public water supply system. Process water would be provided from the effluent of the municipal wastewater treatment plants (WWTPs) of the cities of Mattoon and possibly Charleston, Illinois. Sanitary wastewater service would be provided through an extension of Mattoon's public wastewater system. Natural gas would be delivered through a high-pressure line that is within 0.25 mile (0.4 kilometer) of the proposed site. The proposed power plant would connect to the power grid via existing or new high voltage transmission lines. Following Table 2-1, Figures 2-4 and 2-5 illustrate the Mattoon Site and utility corridors, respectively.

Table 2-1. Mattoon Site Features

Feature	Description
Power Plant Site	The proposed Mattoon Power Plant and Sequestration Site consists of approximately 444 acres (180 hectares) located in Mattoon Township, Coles County, Illinois. The proposed site consists of 93 percent farmland and 3 percent public rights-of-way (ROWs), with the remaining percentage being rural residential development and woodlands. The Site Proponent is a group consisting of the State of Illinois (through the Illinois Department of Commerce and Economic Opportunity), the City of Mattoon, Coles County, and Coles Together (an economic development organization). The proposed site is currently privately owned, but the Site Proponent has an option to purchase the site title, which would be conveyed to the Alliance. The northeast boundary of the proposed site is adjacent to SR 121. Rail access is immediately adjacent to the northeast site boundary. The proposed power plant site is located approximately 1 mile (1.6 kilometers) northwest of Mattoon and approximately 150 miles (241.4 kilometers) south of Chicago. This Coles County site is used as farmland, is flat, and is surrounded by a rural area of low-density population.
Sequestration Site Characteristics and Predicted Plume Radius	The sequestration site is located on the same parcel of land as the power plant site. CO_2 injection would occur within the Mt. Simon saline-bearing sandstone at a depth of 1.3 to 1.6 miles (2.1 to 2.6 kilometers). The Mt. Simon formation is overlain by a thick (500- to 700-foot [152- to 213-meter]) regional seal of low permeability siltstones and shales of the Eau Claire formation and is underlain by Precambrian granitic rock.

Table 2-1. Mattoon Site Features

Feature	Description
Sequestration Site Characteristics and Predicted Plume Radius (continued)	The St. Peter sandstone is proposed as an optional target reservoir. It occurs at a depth of 0.9 mile (1.4 kilometers), which is about 0.4 mile (0.6 kilometer) above the Mt. Simon formation. The St. Peter sandstone is estimated to be over 200 feet (61 meters) thick with state-wide lateral continuity. Both the Mt. Simon and St. Peter reservoirs have been successfully used for natural gas storage in other parts of Illinois. To estimate the size of the plume of injected CO_2, the Alliance used numerical modeling to predict the plume radius from the injection well. This modeling estimated that the plume radius at Mattoon could be as large as 1.2 miles (1.9 kilometers) after injecting 1.1 million tons (1 MMT) of CO_2 annually for 50 years. The dispersal and movement of the injected CO_2 would be influenced by the geologic properties of the reservoir, and it is unlikely that the plume would radiate in all directions from the injection point in the form of a perfect circle. However, for reference purposes, this modeled radius corresponds to a circular area equal to 2,789 acres (1,129 hectares). Data from a recent two-dimensional (2D) seismic line across the proposed injection site indicated that the continuity of the seismic reflectors on this seismic line suggests that there is no significant faulting cutting the plane on the seismic line within 1.5 miles (2.4 kilometers) to the west and 1.5 miles (2.4 kilometers) to the east of the Mattoon Sequestration Site (Patrick Engineering, 2006).
Utility Corridors	
Potable Water	Potable water would be supplied to the plant site from the Mattoon public potable water system. A 1-mile (1.6-kilometer) pipeline extension would be constructed within the ROW of County Road (CR) 800N from the proposed power plant site to a 10-inch (25-centimeter) potable water pipeline on 43rd Street south of SR 121.
Process Water	The proposed Mattoon Site would obtain process water from the effluent of the municipal WWTPs of Mattoon and possibly Charleston. For the Mattoon WWTP effluent, a 6.2-mile (10.0-kilometer) pipeline would be constructed, with all but 2 miles (3.2 kilometers) within an existing public ROW located within the city boundary. The Site Proponent has option contracts to buy the necessary easements for these 2 miles (3.2 kilometers) of pipeline. The possible addition of a new 8.1-mile (13.0-kilometer) pipeline from the Charleston WWTP would be within an existing ROW owned by Mattoon and Charleston. The jointly-owned ROW follows the Lincoln Prairie Grass Bike Trail, and existing 138-kilovolt (kV) overhead electric lines run the entire length. ***Additionally, after issuance of the Draft EIS, a slight modification of the 6.2 mile (10.0 kilometer) process water pipeline was submitted to the Alliance by the Site Proponent (see Sections S.4.3, 2.4.5, 4.1 and Tables S-1, S-12, and 3-3).*** An on-site reservoir (on the power plant property) could be constructed to store up to 25 million gallons (94.6 million liters) of process water to satisfy water requirements. A small reservoir of 7 acres (2.8 hectares) would be adequate. If a larger reservoir were constructed (approximately 40 acres [16.2 hectares] in size) with a capacity of 200 million gallons (757 million liters), the Mattoon WWTP effluent would be sufficient by itself to supply the proposed plant's process water.
Sanitary Wastewater	Sanitary wastewater service would be provided to the proposed plant site through an extension of Mattoon's existing public wastewater system. A sanitary sewer lift station would be constructed at the proposed site. A 1.25-mile (2.0-kilometer) wastewater force main would then be constructed in the ROW of SR 121 to an existing sanitary lift station at the intersection of SR 121 and 43rd Street.
Electric Transmission Lines	Option 1: The proposed power plant would connect with an existing 138-kV transmission line located 0.5 mile (0.8 kilometer) from the proposed site. This line runs north-south and is owned by Ameren Corporation. A corridor easement to connect the proposed site to the existing 138-kV line has already been acquired by Mattoon. There are three scenarios to tie into this line under Option 1.

Table 2-1. Mattoon Site Features

Feature	Description
Electric Transmission Lines (continued)	Option 1a: Tie directly into the existing 138-kV line with transfer switching. Option 1b: Install a substation at the interconnection of the new easement with the existing ROW. Option 1c: Run a new transmission line south next to the existing 138-kV line and connect with the existing substation less than 2 miles (3.2 kilometers) away near Route 16. The existing substation would need to be upgraded. Option 2: Under this option, the proposed site would be connected to the nearest 345-kV line at the Neoga South Substation located 16 miles (25.7 kilometers) south of the proposed site. This option would require 16 miles (25.7 kilometers) of new line and ROW to connect the proposed plant with this substation.
Natural Gas	A natural gas mainline is located approximately 0.25 mile (0.4 kilometer) east of the proposed power plant site. This is a high-pressure line, and a new tap and delivery station would be required. The Site Proponent has obtained an option for additional land for the pipeline ROW that would give flexibility in the route to connect to this line.
CO_2 Pipeline	The CO_2 injection well for the FutureGen Project at Mattoon would be located at the proposed power plant site. Therefore, no off-site CO_2 pipeline or corridor would be necessary.
Transportation Corridors	The site is located 7 miles (11.3 kilometers) west of Interstate (I) Highway 57 (I-57), along SR 121. The Canadian National-Peoria Subdivision rail line is immediately adjacent to the northeast site boundary. The Canadian National/Illinois Central mainline connects to the Peoria Subdivision rail line approximately 3.5 miles (5.6 kilometers) from the proposed site. Illinois is located within the East North Central Demand Region for coal, which also includes Ohio, Indiana, Wisconsin, and Michigan. According to the Energy Information Administration (EIA, 2000), the East North Central Demand Region is ideally situated for access to coal, which it receives from each of the major U.S. supply regions. In 1997, the average distance that a coal shipment traveled to reach a destination in this region was about 830 miles (1,336 kilometers) (EIA, 2000). In terms of a straight-line distance, Mattoon is approximately 300 miles (483 kilometers) from the Pittsburgh Coalbed (near south-central Ohio in the northern Appalachian Basin), 900 miles (1,448 kilometers) from the Powder River Basin (PRB) (eastern Wyoming), and 50 miles (80.5 kilometers) from the nearest active coal mine within the Illinois Basin (Vermillion County, Illinois).

Source: FG Alliance, 2006b (unless otherwise noted).

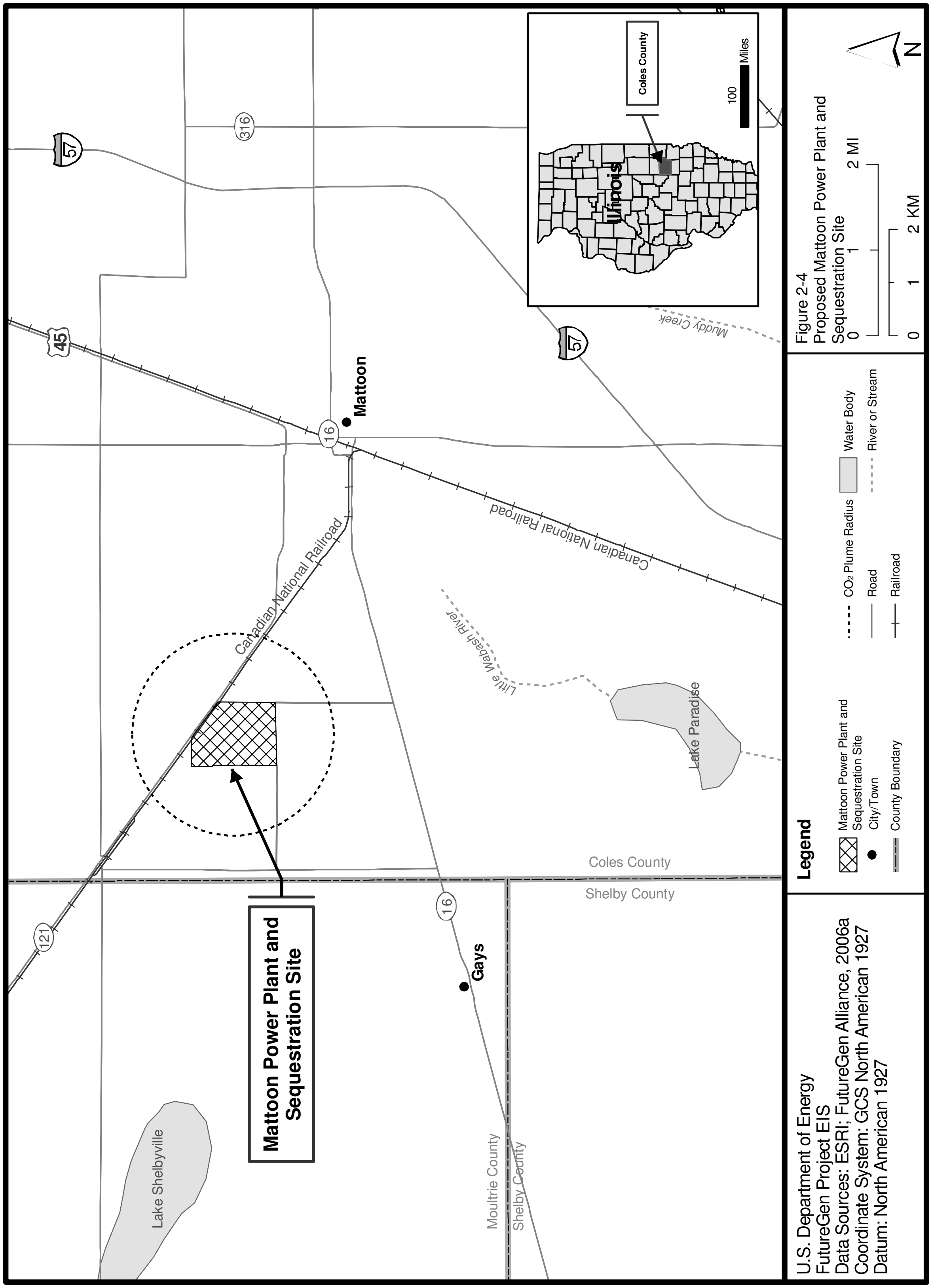


Figure 2-4
Proposed Mattoon Power Plant and Sequestration Site

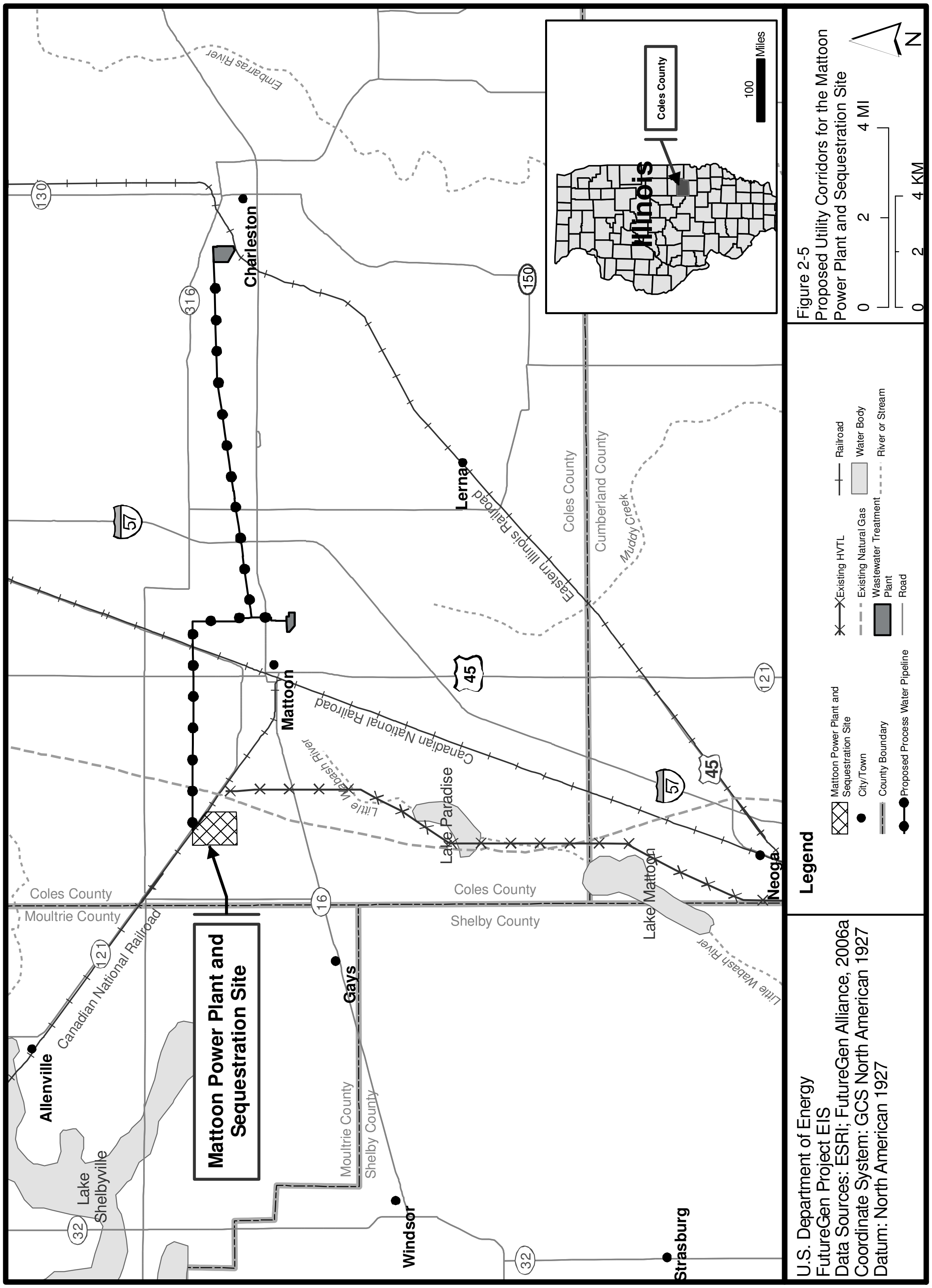


Figure 2-5
Proposed Utility Corridors for the Mattoon Power Plant and Sequestration Site

2.4.2 TUSCOLA SITE

Proposed Tuscola Power Plant Site

The proposed Tuscola Site consists of approximately 345 acres (140 hectares) of farmland located approximately 1.5 miles (2.4 kilometers) west of the City of Tuscola, in Douglas County, Illinois. Key features of the Tuscola Site are listed in Table 2-2. Township Road (TR) 86 (750E) borders the western side of the proposed plant site and TR 47 (1050N) runs along its northern border. A CSX Railroad runs along its southern border. Potable water would be supplied through an existing water line along the southern border of the proposed site. Process water would be pumped from a water holding pond fed by the Kaskaskia River and located at the nearby Lyondell-Equistar Chemical Company. Sanitary wastewater would be treated either through a new on-site WWTP or by constructing a new sanitary force-main to the wastewater treatment system at the Lyondell-Equistar plant. The proposed power plant would connect to the power grid via existing or new high voltage transmission lines. Natural gas would be delivered through an existing line that runs through the proposed plant site. The proposed sequestration site is currently farmland situated 11 miles (17.7 kilometers) directly south of the proposed plant site. A new CO_2 pipeline would be constructed within the existing road and utility ROWs, and new ROWs running parallel to existing ROWs if required. Following Table 2-2, Figures 2-6, 2-7, and 2-8 illustrate the Tuscola Power Plant Site, utility corridors, and sequestration site, respectively.

Table 2-2. Tuscola Site Features

Feature	Description
Power Plant Site	The proposed Tuscola Site consists of approximately 345 acres (140 hectares) located in east-central Illinois, 1.5 miles (2.4 kilometers) west of the City of Tuscola within Douglas County. TR 86 (750E) runs along the west border of the proposed plant site and TR 47 (1050N) runs along its northern border. The Site Proponent is a group consisting of the State of Illinois (through the Illinois Department of Commerce and Economic Opportunity), the City of Tuscola, Douglas County, and Tuscola Economic Development, Inc. The proposed site is currently privately owned, but the Site Proponent has an option to purchase the site title, which would be conveyed to the Alliance. The proposed site is located on flat farmland near an industrial complex, which is immediately west of the proposed site. The areas to the immediate north, east, and south are rural with a very low population density.
Sequestration Site Characteristics and Predicted Plume Radius	The proposed sequestration site is located in a rural area, approximately 2 miles (3.2 kilometers) south-southwest of the small town of Arcola in Douglas County in east-central Illinois. The proposed site is located 11 miles (17.7 kilometers) south of the proposed power plant site and is 3 miles (4.8 kilometers) west of I-57. The proposed sequestration site would be located on a land trust, where the trustee is the First National Bank of Arcola. The trustee has been authorized by the beneficiaries of the trust to sell the property. The proposed site is a 10-acre (4-hectare) portion of a larger parcel of 80 acres (32.4 hectares). The proposed sequestration site is located in Arcola Township, Douglas County, approximately 0.25 mile (0.4 kilometer) east of CR 750E along 000N, the Douglas-Coles County line. The site consists primarily of agricultural land with row crops.

Table 2-2. Tuscola Site Features

Feature	Description
Sequestration Site Characteristics and Predicted Plume Radius (continued)	Injection would occur within the Mt. Simon saline-bearing sandstone, at a depth of between 1.3 to 1.5 miles (2.1 to 2.4 kilometers). The Mt. Simon formation is overlain by a thick (500- to 700-foot [152- to 213-meter]) regional seal of low permeability siltstones and shales of the Eau Claire Formation and is underlain by Precambrian granitic rock. The St. Peter sandstone is proposed as an optional target reservoir. It occurs at a depth of 0.9 mile (1.4 kilometers), which is about 0.4 mile (0.6 kilometer) above the Mt. Simon formation. The St. Peter reservoir is estimated to be over 100 feet (30.5 meters) thick with state-wide lateral continuity. Both the Mt. Simon and St. Peter reservoirs have been successfully used for natural gas storage in other parts of Illinois. To estimate the size of the plume of injected CO_2, the Alliance used numerical modeling to predict the plume radius from the injection well. This modeling estimated that the plume radius at the proposed Tuscola injection site could be as large as 1.1 miles (1.8 kilometers) after injecting 1.1 million tons (1 MMT) of CO_2 annually for 50 years. The dispersal and movement of the injected CO_2 would be influenced by the geologic properties of the reservoir, and it is unlikely the plume would radiate in all directions from the injection point in the form of a perfect circle. However, for reference purposes, this modeled radius corresponds to a circular area equal to 2,432 acres (984 hectares). A recent 2D seismic line across the proposed injection site indicated that the continuity of seismic reflectors on this seismic line suggest that there is no significant faulting cutting the plane of the seismic line within 1 mile (1.6 kilometers) to the west and 2.5 miles (4.0 kilometers) to the east of the Tuscola Sequestration Site (Patrick Engineering, 2006).
Utility Corridors	
Potable Water	Potable water would be supplied to the proposed power plant by tapping an existing 8-inch (20.3-centimeter) water line operated by the Illinois American Water Company. This line runs along the southern boundary of the property along the CSX Railroad. Tapping into the existing water line would require less than 1 mile (1.6 kilometers) of new construction.
Process Water	The proposed power plant would receive its process water from an existing 150 million-gallon (568 million-liter) water holding pond at the Lyondell-Equistar Chemical Company located west of the proposed site. This pond contains raw water pumped from the adjacent Kaskaskia River. A 1.5-mile (2.4-kilometer) force main would be constructed to pump water from the pond to the plant, crossing property owned by Lyondell-Equistar Chemical Company and Cabot Corporation, as well as an existing township ROW.
Sanitary Wastewater	Option 1: Under Option 1, an on-site WWTP would be constructed at the proposed plant site. The treated effluent from this facility could then be discharged into an on-site reservoir (if constructed) and then reused as process water. Option 2: Under Option 2, a 0.9-mile (1.4-kilometer) sanitary force-main would be constructed to the existing wastewater treatment system at the Lyondell-Equistar Chemical Company. Once treated, this effluent could potentially be discharged into the existing 150 million-gallon (568 million-liter) reservoir to be reused as process water for the proposed power plant. There is an abandoned 8-inch (20.3-centimeter) potable water pipeline at the property that could potentially be used as a sanitary force-main to the Lyondell-Equistar WWTP. This line would require hydraulic testing before it could be put into service.
Electric Transmission Lines	Option 1: The nearest electric transmission line to the proposed power plant site is a 138-kV line located 0.5 mile (0.8 kilometer) north of the proposed site. This line is owned and operated by Ameren Corporation. The connection to this line would require additional ROW. Under Option 1, the proposed plant would tie into this existing 138-kV line.

Table 2-2. Tuscola Site Features

Feature	Description
Electric Transmission Lines (continued)	Option 2: If the interconnection of the proposed plant to the electric grid required use of a 345-kV line, a new 345-kV line that would parallel or replace the existing 138-kV line would be constructed for approximately 17 miles (27.4 kilometers) and connect to a substation where the line currently joins the 345-kV Sidney-Kansas line. Approximately 3 miles (4.8 kilometers) of new ROW would be required. An interconnection study has been requested and would dictate the ultimate line requirements.
Natural Gas	Natural gas would be delivered to the proposed plant from an existing natural gas mainline that runs through the proposed power plant site. Because the pipeline is a high-pressure line, a new tap and delivery station would be required.
CO_2 Pipeline	A new 11-mile (17.7-kilometer) pipeline would be constructed to transport CO_2 to the proposed sequestration site 10 miles (16.1 kilometers) due south of the proposed plant site. The pipeline would be constructed across existing State of Illinois, Douglas County, and Township ROWs and would occupy new ROWs where needed. The pipeline corridor would run parallel to CR 750E and 700E to the injection location.
Transportation Corridors	There are four railroads nearby: CSX Transportation borders site, Union Pacific (1.5 miles [2.4 kilometers]), Canadian National (1.5 miles [2.4 kilometers]), and Norfolk Southern (approximately 30 miles [48.3 kilometers]). The proposed site is bordered by TR 86 and TR 47. Illinois is located within the East North Central Demand Region for coal, which also includes Ohio, Indiana, Wisconsin, and Michigan. According to the Energy Information Administration (EIA, 2000), the East North Central Demand Region is ideally situated for access to coal, which it receives from each of the major U.S. supply regions. In 1997, the average distance that a coal shipment traveled to reach a destination in this region was about 830 miles (1,336 kilometers) (EIA, 2000). In terms of a straight line distance, Tuscola is approximately 300 miles (483 kilometers) from the Pittsburgh Coalbed (near south-central Ohio in the northern Appalachian Basin), 900 miles (1,448 kilometers) from the PRB (eastern Wyoming), and within 35 miles (56.3 kilometers) of the nearest active coal mines in the Illinois Basin (Vermillion County, Illinois).

Source: FG Alliance, 2006c (unless otherwise noted).

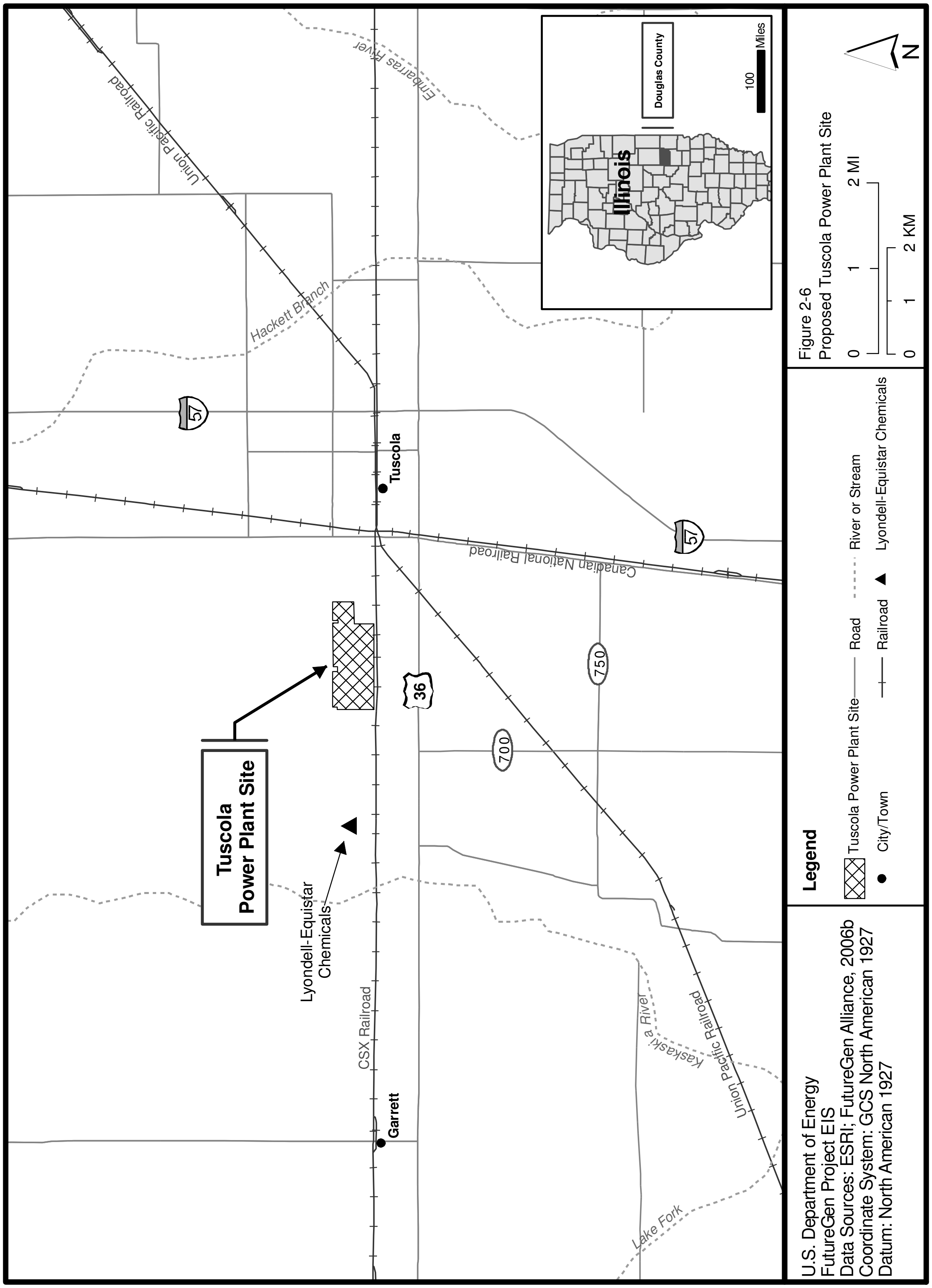


Figure 2-6
Proposed Tuscola Power Plant Site

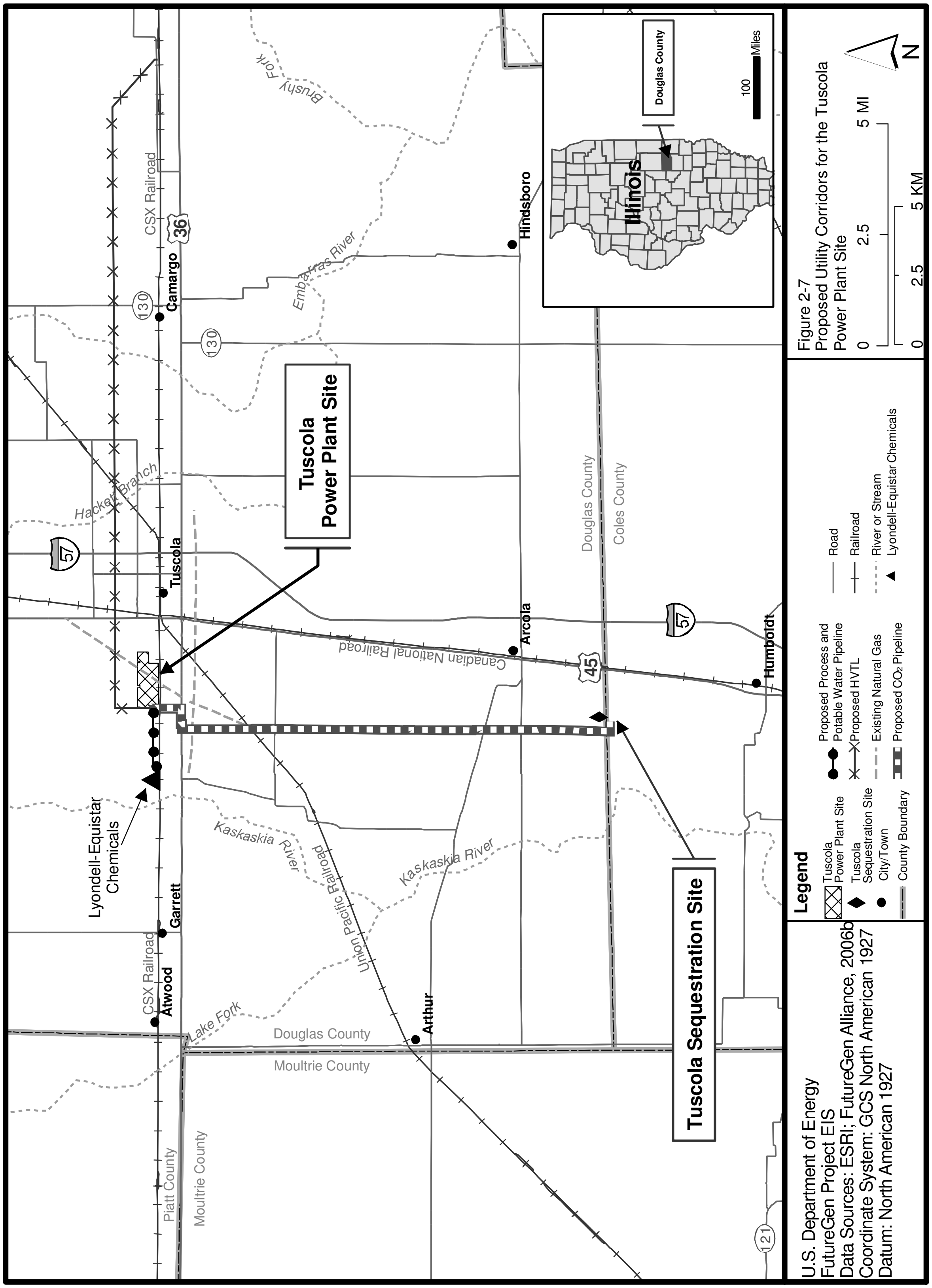


Figure 2-7
Proposed Utility Corridors for the Tuscola Power Plant Site

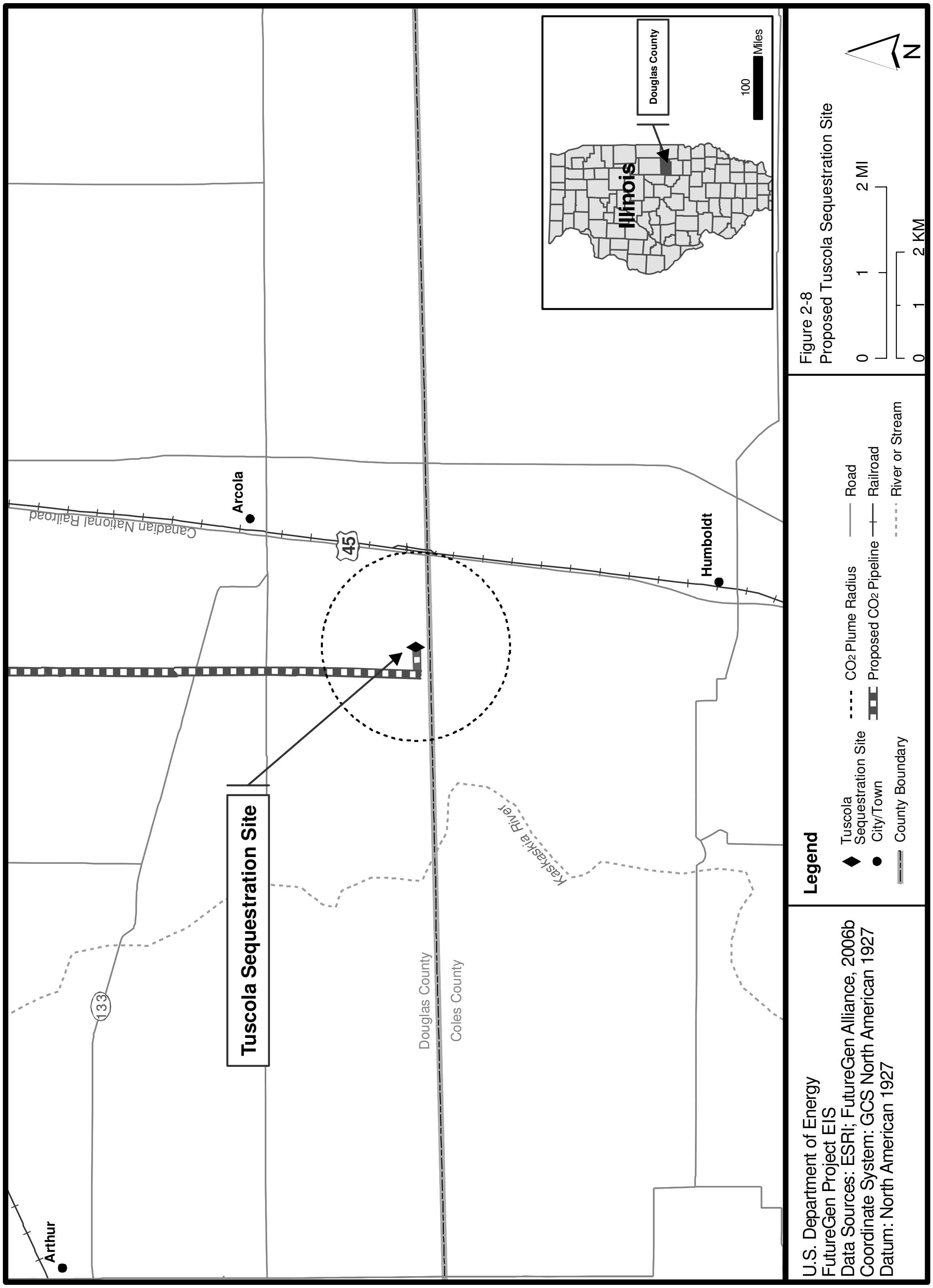


Figure 2-8
Proposed Tuscola Sequestration Site

2.4.3 JEWETT SITE

Proposed Jewett Power Plant Site

(NRG Limestone Generating Station in the background)

The proposed Jewett Site is located in east-central Texas on approximately 400 acres (162 hectares) of formerly mined land northwest of the Town of Jewett. Key features of the Jewett Site are listed in Table 2-3. The proposed site is located at the intersection of Leon, Limestone, and Freestone counties, and bordered by Farm-to-Market Road (FM) 39. The Burlington Northern Santa Fe Railroad runs along the northeastern border of the proposed site. Potable water and process water would be obtained by drilling new wells on site or nearby. Sanitary wastewater would be treated through a new on-site wastewater treatment system. The proposed power plant would connect to the power grid via existing high voltage transmission lines. Natural gas would be delivered through an existing gas pipeline located at the northeastern corner of the proposed plant site. The proposed sequestration injection wells would be located on both private ranchland and state-owned prison land approximately 33 miles (53.1 kilometers) northeast of the proposed power plant site. A new CO_2 pipeline would be installed largely along existing ROWs, but would require some new ROWs. Following Table 2-3, Figures 2-9, 2-10, and 2-11 illustrate the Jewett Power Plant Site, utility corridors, and sequestration site, respectively.

Table 2-3. Jewett Site Features

Feature	Description
Power Plant Site	The proposed Jewett Site is located in east-central Texas on approximately 400 acres (162 hectares) of land northwest of the Town of Jewett. The proposed site is located at the intersection of Leon, Limestone, and Freestone counties on FM 39 near US 79. The area is characterized by very gently rolling reclaimed mine lands immediately adjacent to an operating lignite mine and the nominal 1800-MW NRG Limestone Generating Station (power plant). The Site Proponent is the State of Texas. The proposed power plant site is currently held by one property owner – NRG Texas.
Sequestration Site Characteristics and Predicted Plume Radius	***The proposed Jewett Sequestration Site includes three proposed injection wells located in a rural area about 33 miles (53 kilometers) northeast of the proposed power plant site. Two of the proposed injection well sites are located about 16 miles (28 kilometers) east of the Town of Fairfield in Freestone County, about 60 miles east of Waco. The third proposed injection well site is about 5 miles (8 kilometers) east on Texas Department of Criminal Justice (TDCJ) property in Anderson County about 16 miles (28 kilometers) west of the City of Palestine.*** The land use at the proposed sequestration site is primarily agricultural, with few residences located over the projected plume. Injection would occur on a private ranch (Hill Ranch) and on adjoining state property managed by the TDCJ. Two injection wells are proposed for injection into the Woodbine formation. In addition, one more injection well is proposed for injection into the deeper Travis Peak formation at a much lower injection rate than the primary Woodbine wells to take advantage of CO_2 sequestration research opportunities on low permeability reservoirs. The Travis Peak well would not be required in addition to the Woodbine injection wells to accommodate the output of the proposed power plant. One of the Woodbine injection wells and the Travis Peak well would be located on the Hill Ranch property. The other Woodbine injection well would be located

Table 2-3. Jewett Site Features

Feature	Description
Sequestration Site Characteristics and Predicted Plume Radius (continued)	on TDCJ property. Under the proposed injection plan, each of the Woodbine wells would be used to inject 45 percent of the total CO_2 output with the remaining 10 percent injected into the Travis Peak well. Both the Woodbine and Travis Peak formations lie beneath a primary seal, the Eagle Ford Shale, which has a thickness of 400 feet (122 meters). The primary injection zone, the Woodbine sandstone, is directly beneath the Eagle Ford. There are also over 0.4 mile (0.6 kilometer) of low permeability carbonates and shales above the Eagle Ford that create additional protection for shallow ***underground sources of drinking water***. The injection depth within the Woodbine formation would be 1 to 1.1 miles (1.6 to 1.8 kilometers). Injection into the Travis Peak formation would occur between 1.7 to 2.1 miles (2.7 to 3.4 kilometers) below the ground surface. To estimate the size of the plume of injected CO_2, the Alliance used numerical modeling to predict the plume radius from the injection wells. This modeling estimated that the plume radius at the proposed Jewett injection site could be as large as 1.7 miles (2.7 kilometers) per Woodbine injection well, 50 years after injecting 2.8 million tons (2.5 MMT) of CO_2 annually for the first 20 years, followed by 30 years of gradual plume spreading. The dispersal and movement of the injected CO_2 would be influenced by the geologic properties of the reservoir, and it is unlikely that the plume would radiate in all directions from the injection point in the form of a perfect circle. However, for reference purposes, this modeled radius corresponds to a circular area equal to 5,484 acres (2,219 hectares). A total of 10,968 acres (4,439 hectares) is estimated for all three wells.
Utility Corridors	
Potable Water	Potable water would be supplied in the same manner as the proposed plant's process water, by installing new wells either on the property or off site. This would require 1 mile (1.6 kilometers) of new construction.
Process Water	Process water would be provided by installing wells on the proposed site or possibly off site into the Carrizo-Wilcox Aquifer. Because the wells would be located on or close to the proposed plant site, only a small length of distribution pipeline, less than 1 mile (1.6 kilometers), would be required to deliver water to the proposed plant.
Sanitary Wastewater	Sanitary wastewater would be treated and disposed of through construction and operation of an on-site sanitary WWTP. Effluent from the WWTP would be treated and disposed of in accordance with local and state regulations or recycled back into the power plant for process water.
Electric Transmission Lines	Option 1: The proposed power plant would connect to a 345-kV transmission line bordering the plant site. Option 2: The proposed power plant would connect to a 138-kV line approximately 2 miles (3.2 kilometers) from the site on a new ROW.
Natural Gas	Natural gas would be delivered through an existing natural gas pipeline located at the northwestern corner of the proposed power plant site. This pipeline is owned and operated by Energy Transfer Corporation.
CO_2 Pipeline	A new CO_2 pipeline would be required to connect the proposed power plant site to the proposed sequestration site. The pipeline would be up to 59 miles (95 kilometers) in length and the ROW would be approximately 20 to 30 feet (6.1 to 9.1 meters) wide. The proposed CO_2 pipeline has been divided into the following common segments, except for segments A-C and B-C, which are alternatives between the proposed plant site and the beginning of segment C: • Segment A-C would begin on the northeastern side of the proposed plant site and follow 2 miles (3.2 kilometers) of existing ROW owned by the Burlington Northern – Santa Fe Railroad. It would continue approximately 3 miles (4.8 kilometers) along a new ROW until it intersects a section of a natural gas pipeline ROW. The corridor would then follow this pipeline another 3 miles (4.8 kilometers) east until it joins a larger trunk of a natural gas pipeline.

Table 2-3. Jewett Site Features

Feature	Description
CO_2 Pipeline (continued)	• Segment B-C would begin along the southern boundary of the proposed plant site and extend southeast approximately 2.5 miles (4.0 kilometers) along FM 39. It then would turn northeast and follow the existing ROW of a natural gas pipeline for another 4 miles (6.4 kilometers) until it joins a ROW for a larger trunk of a natural gas pipeline that extends northwest for approximately 8 miles (12.9 kilometers). • Segment C-D would follow an existing natural gas line ROW northward for approximately 15 miles (24.1 kilometers). • Segment D-E is no longer being evaluated for this project; therefore, it is not addressed in this EIS. • Segment D-F would continue northward along the existing natural gas line ROW for another 9 miles (14.5 kilometers). • Segment F-G would extend in a straight line east along a new ROW approximately 6 miles (9.7 kilometers) to the proposed sequestration wells on the Hill Ranch. • Segment F-H would continue northward along the existing natural gas line corridor for almost 2 miles (3.2 kilometers) where it would cross the Trinity River to the north side. It then would intersect another leg of a natural gas pipeline ROW and continue east for approximately 6 miles (9.7 kilometers). The line would then continue in a generally eastward direction along a county highway (CH) ROW and TDCJ land for approximately another 6 miles (9.7 kilometers) to the proposed injection well site on TDCJ land.
Transportation Corridors	The proposed Jewett Site is bordered by FM 39, which intersects US 79 and State Highway (SH) 164 within 10 miles (16.1 kilometers) of the site boundary. The Burlington Northern – Santa Fe Railroad also runs along the northeastern border of the proposed power plant site. Texas is located in the West South Central Demand Region for coal, which also includes Louisiana, Arkansas, and Oklahoma. According to the Energy Information Administration (EIA, 2000), the West South Central Demand Region receives the majority of its coal resources from the PRB and the Rockies. In 1997, the average distance that a coal shipment traveled to reach a destination in this region was about 1,300 miles (2,092 kilometers) (EIA, 2000). In terms of a straight line distance, Jewett is approximately 950 miles (1,529 kilometers) from the Pittsburgh Coalbed (south-central Ohio in the northern Appalachian Basin), 650 miles (1,046 kilometers) from the Illinois Basin coals (southern Illinois), and 1,000 miles (1,609 kilometers) from the PRB coal supplies (eastern Wyoming). In addition, Texas lignite is available from the on-site Westmoreland Coal Company mine and perhaps other regional mines.

Source: FG Alliance, ***2006e*** (unless otherwise noted).

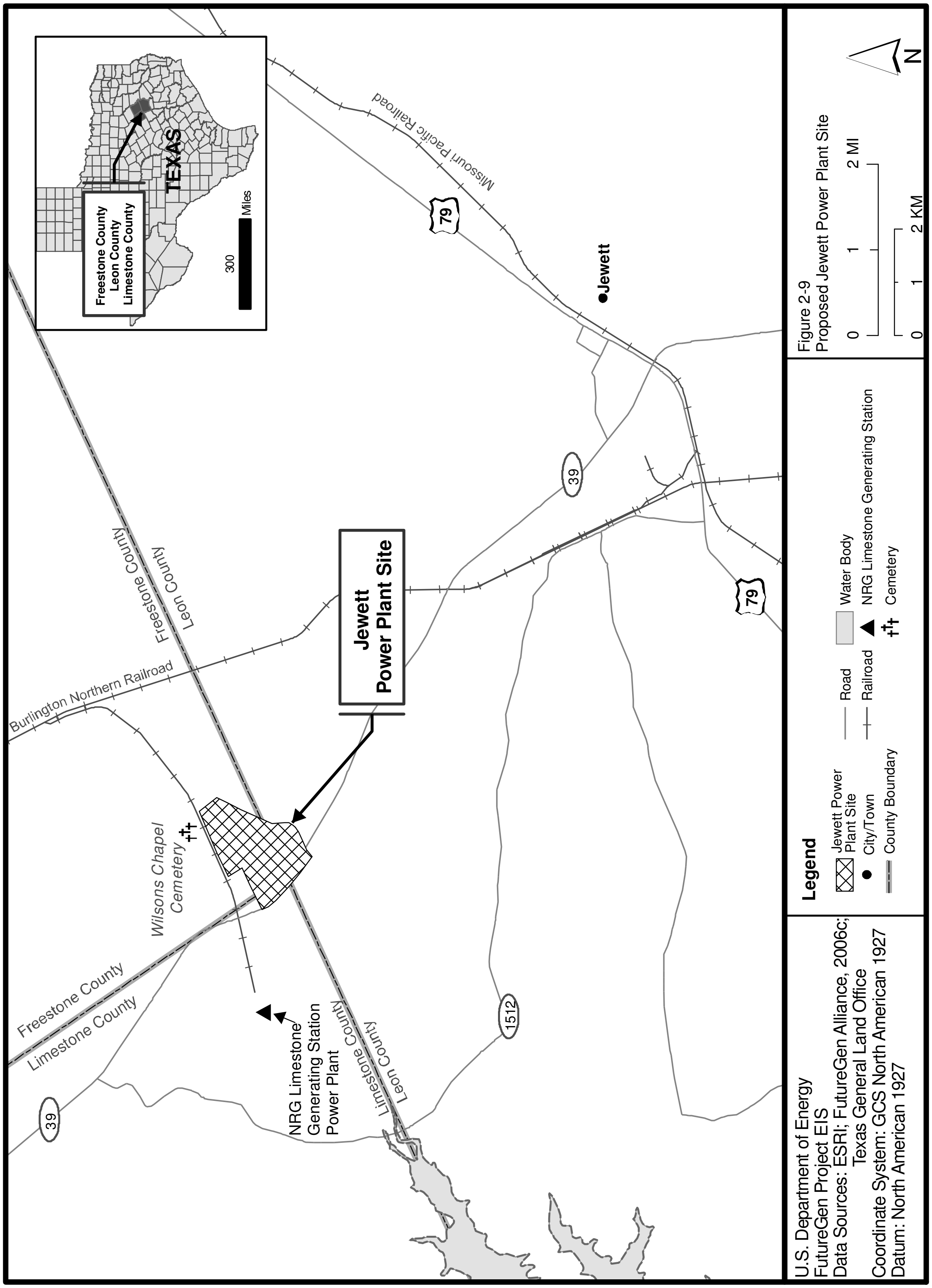


Figure 2-9
Proposed Jewett Power Plant Site

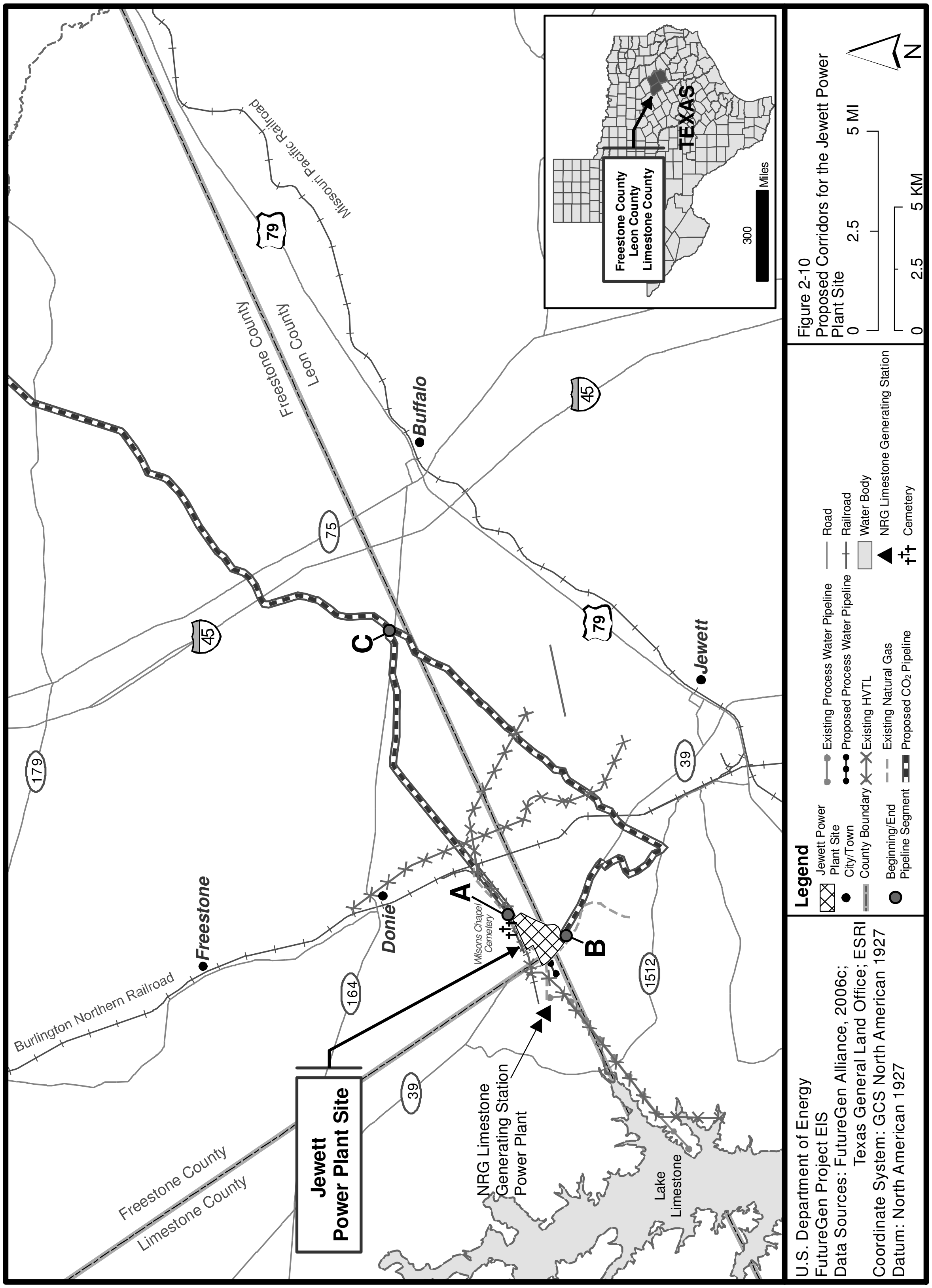


Figure 2-10
Proposed Corridors for the Jewett Power Plant Site

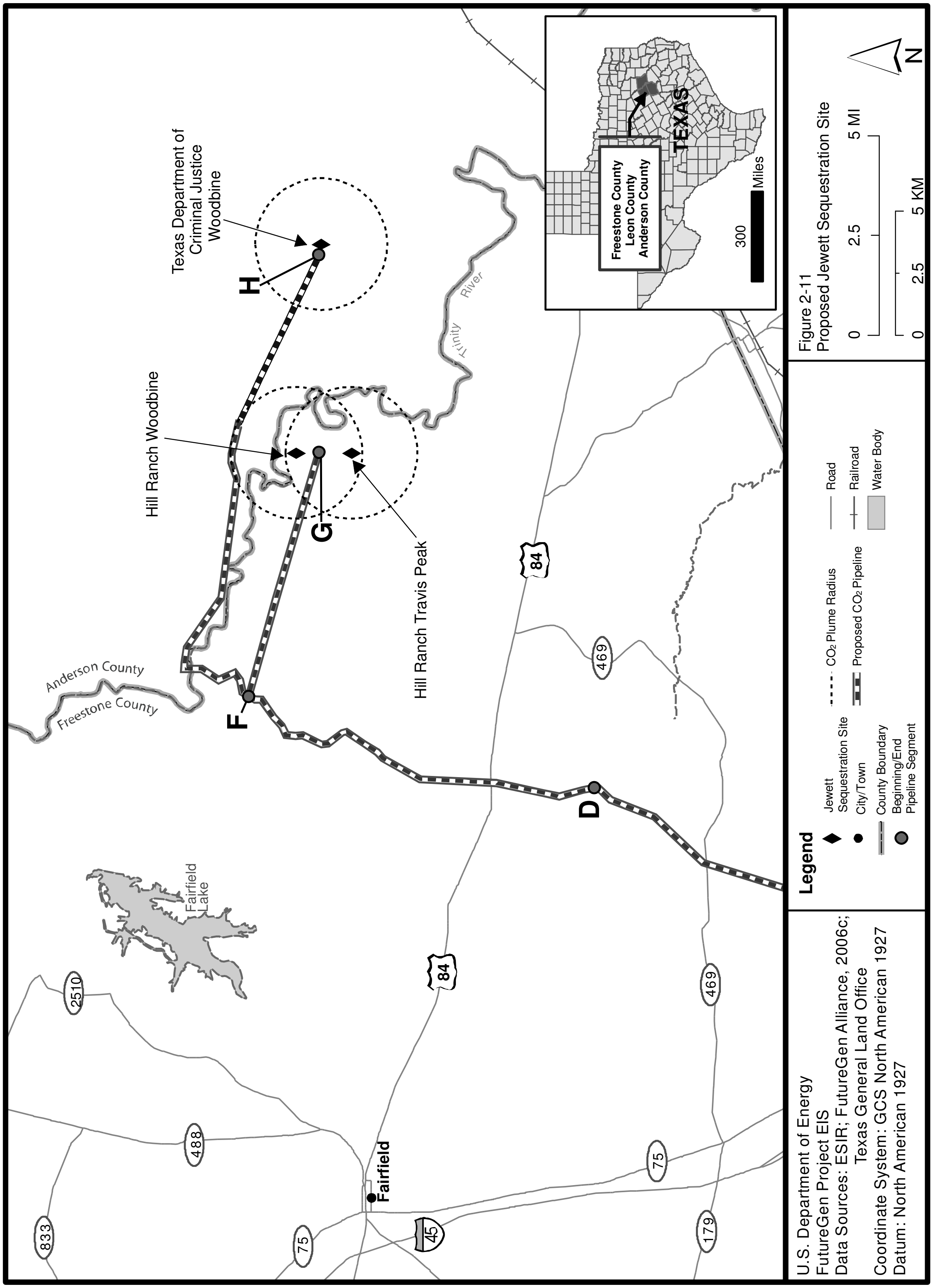


Figure 2-11
Proposed Jewett Sequestration Site

2.4.4 ODESSA SITE

Proposed Odessa Power Plant Site

The proposed Odessa Site is located on approximately 600 acres (243 hectares) 15 miles (24.1 kilometers) southwest of the City of Odessa in Ector County, Texas. Key features of the Odessa Site are listed in Table 2-4. The proposed site is located just north of I-20 and is north of the Town of Penwell and a Union Pacific Railroad. The land has historically been used for ranching as well as oil and gas activities. Potable water and process water would be obtained by developing new well fields nearby or from several existing water well fields ranging from 24 to 54 miles (38.6 to 86.9 kilometers) from the proposed plant site ***or possibly from the Colorado River Municipal Water District (CRMWD) (see Sections S.4.3 and 2.4.5)***. Sanitary wastewater would be treated through construction and operation of an on-site treatment system. The proposed power plant would connect to the power grid via existing high voltage transmission lines located approximately 1.8 miles (2.9 kilometers) from the site. Natural gas would be obtained from an existing gas pipeline that traverses the proposed plant site.

The proposed sequestration site would be located 58 miles (93.3 kilometers) south of the proposed power plant site on ***42,300*** acres (17,118 hectares) on University of Texas land. An existing CO_2 pipeline would transport the power plant's CO_2 to the sequestration site, although up to 14 miles (22.5 kilometers) of new CO_2 pipeline would be installed to connect the proposed power plant and the proposed sequestration site to the existing pipeline. ***Additionally, after issuance of the Draft EIS, two additional and reasonable CO_2 pipeline options were submitted to DOE (see Sections S.4.3 and 2.4.5). Option 1 would involve the construction and operation of a new, approximately 90-mile (145-kilometer) pipeline along existing ROWs; and Option 2 which would involve the use of existing pipeline and the construction of a new, approximately 30-mile (48-kilometer) pipeline and a separate sulfur removal plant.*** Following Table 2-4, Figures 2-12, 2-13, and 2-14 illustrate the Odessa Power Plant Site, utility corridors, and sequestration site, respectively.

Table 2-4. Odessa Site Features

Feature	Description
Power Plant Site	The proposed Odessa Site is located on about 600 acres (243 hectares) approximately 15 miles (24.1 kilometers) southwest of the City of Odessa in Ector County, Texas. The proposed site consists of flat land near I-20 and across the Union Pacific Railroad from the Town of Penwell. The Site Proponent is the State of Texas. Both the proposed site and surrounding land to the east, west, and north are rural areas where land use has been dominated historically by ranching and oil and gas activities (Horizon Environmental Services, 2006). Unimproved roads and structures related to oil and gas well activities are found on and around the proposed site, with most oil production activities historically occurring immediately west of the proposed site. Several pipelines also traverse the proposed site boundaries. The entire property within the proposed power plant site boundary is owned by a single owner.

Table 2-4. Odessa Site Features

Feature	Description
Sequestration Site Characteristics and Predicted Plume Radius	The proposed sequestration site is located in a semi-arid, sparsely populated area adjacent to I-10 in Pecos County, Texas. The proposed site, owned by the University of Texas, is located 58 miles (93.3 kilometers) south of the proposed power plant near Odessa, Texas, and is about 60 miles (96.6 kilometers) south of the Midland-Odessa International Airport. ***The proposed injection site would be approximately 13 miles (21 kilometers) east of Fort Stockton, Texas.*** ***Proposed injection targets for this site include a lower interval (the Delaware Mountain Group sandstones) and an upper interval (the lower part of Queen formation sandstones).*** The injection target would be at a depth of between 0.4 mile to 1 mile (0.6 to 1.6 kilometers). These sandstone intervals are separated by an intermediate seal that consists primarily of non-porous and impermeable carbonates of the Goat Seep Limestone. The upper injection horizon is overlain by a 700-foot (213-meter) thick primary seal, the Queen-Seven Rivers formation. To estimate the size of the plume of injected CO_2, the Alliance used numerical modeling to predict the plume radius from the proposed injection wells. This modeling estimated that the plume radius at the proposed Odessa injection site could be as large as 1 mile (1.6 kilometers) per well after injecting 1.1 million tons (1 MMT) of CO_2 annually for 50 years. The dispersal and movement of the injected CO_2 would be influenced by the geologic properties of the reservoir and it is unlikely the plume would radiate in all directions from the injection point in the form of a perfect circle. However, for reference purposes, this modeled radius corresponds to a circular area equal to 2,136 acres (864 hectares). A minimum of three wells would be required to support a constant 1.1 million tons (1 MMT) per year injection rate. A minimum of eight wells would be needed to support a 2.8 million tons (2.5 MMT) per year injection rate. Assuming a total of 55 million tons (50 MMT) of CO_2 is injected, the total plume area would be 6,980 acres (2,825 hectares) assuming eight wells would be required to inject 2.8 million tons (2.5 MMT) per year for the first 20 years of a 50-year time period. A slightly smaller area (6,073 acres [2,458 hectares]) would be required if only three wells were needed to inject 1.1 million tons (1 MMT) per year for each year in a 50-year time period. ***The sequestration site contains an estimated 42,300 acres (17,118 hectares) of land.***
Utility Corridors	
Potable Water	Potable water would potentially be obtained through the same sources identified for process water.

Table 2-4. Odessa Site Features

Feature	Description
Process Water	Process water could be acquired by developing new well fields or from several existing well fields that draw water from the Ogallala, Pecos Valley, Edwards-Trinity Plateau, Dockum, or Capitan Reef aquifers. Six existing well fields have been identified that could deliver water to the site, ranging from 24 to 54 miles (38.6 to 86.9 kilometers) from the proposed power plant site (straight-line distance). Any of these six potential sources would require pipeline construction along new ROWs. ***Since the issuance of the Draft EIS, the Site Proponents have provided another process water option. Odessa has offered to provide raw or treated water from the City of Odessa's water treatment plant using a new, approximately 17-mile (27.4-kilometer), process water pipeline (see Figure S-A). All but 1 mile (1.6 kilometers), approximately 5,000 feet (1,524 meters), of the distance of the new process water pipeline would either use existing public road ROWs (e.g., it would be installed under ground on the north side of 42nd Street) or be within the region of influence (ROI) analyzed in the Draft EIS for the Texland Great Plains water corridor. The new, less than 1-mile (1.6-kilometer) corridor requiring new ROW would traverse rangeland similar to that described for the Texland Great Plains water corridor.*** ***The water supply would be from the City of Odessa which receives its raw water from the Colorado River Municipal Water District (CRMWD). The CRMWD is the legislatively created entity whose mission is to provide water to several communities in this region of Texas. The CRMWD currently owns and utilizes three reservoirs and four active well fields (the groundwater is typically used only during summer months to meet peak demands) (City of Odessa, 2007).***
Sanitary Wastewater	Sanitary wastewater would be treated and disposed of through construction and operation of a new on-site sanitary WWTP. Effluent from the WWTP would be treated and disposed of in accordance with local and state regulations or recycled back into the proposed power plant for use as process water.
Electric Transmission Lines	The proposed power plant would connect with one of two 138-kV transmission lines, one approximately 0.7 mile (1.1 kilometers) on new ROW and the second approximately 1.8 miles (2.9 kilometers) on existing ROW from the proposed site. In either case, the interconnection would only require the construction of a substation and a short transmission line to tie into these lines. The southern corridor would follow an existing ROW along FM 1601, which borders the proposed site, while a new ROW would be required for the northern route option.
Natural Gas	The proposed power plant would tap an existing natural gas pipeline that traverses the proposed plant site and that is owned and operated by ATMOS Energy.

Table 2-4. Odessa Site Features

Feature	Description
CO_2 Pipeline	***As proposed in the Draft EIS**,* the proposed injection wells would be located on 42,300 acres (17,118 hectares) of University of Texas lands, 58 miles (93.3 kilometers) south of the proposed Odessa Power Plant Site. CO_2 would be transported in (and co-mingled in) an existing ***CO_2 pipeline with varying diameter just east of the plant site operated by Kinder Morgan CO_2 Company (the Central Basin CO_2 pipeline). The CO_2 would then flow into one or two pipelines owned by PetroSource Inc. (the Comanche Creek Pipeline or the Val Verde Pipeline).*** Two miles (3.2 kilometers) of new CO_2 pipeline would connect the proposed power plant site to the existing ***Central Basin pipeline**,* and approximately 7 to 14 miles (11.3 to 22.5 kilometers) of new pipeline would connect the existing ***PetroSource pipelines*** to the proposed injection site. Because multiple injection wells would be used, intra-well piping would also be installed to connect the wells to the main pipelines. ***Since issuance of the Draft EIS, Alliance and DOE investigations have revealed that it would not be feasible at this time to transport CO_2 from the proposed power plant site at Odessa to the proposed injection well site using the PetroSource Val Verde CO_2 pipeline located east of the injection site, as originally stated in the Draft EIS. Therefore, Odessa has offered two additional CO_2 pipeline options:*** • ***Option 1- Construction and operation of a new, approximately 90-mile (145-kilometer) dedicated pipeline from the FutureGen plant to the injection site along existing rights-of-way; and*** • ***Option 2 – Use of existing pipeline owned by Kinder Morgan CO_2 Company and the construction and operation of a new, approximately 30-mile (48-kilometer) dedicated pipeline (ranging from 6 to 12 inches [15.2 to 30.5 cm] in diameter) from the end of the Kinder Morgan line (near McCamey, Texas) to the injection sites. Option 2 would require additional sulfur removal either at the FutureGen plant or in a separate sulfur removal plant operated by Kinder Morgan.*** ***The original option could be used to transport CO_2 to the sequestration site only through the PetroSource Inc. Comanche Creek Pipeline (it was learned that the Val Verde Pipeline flows the wrong direction). The Comanche Creek Pipeline is a 6-inch (15.2 cm) diameter pipeline that with upgrades, could carry only enough CO_2 to reach the goal of MMT/yr, but it could not deliver the maximum amount that could be captured by FutureGen's 2.8 MMT/yr.***
Transportation Corridors	The southern border of the proposed plant site is less than 0.5 mile (0.8 kilometer) from I-20, with an improved roadway that borders the property. A Union Pacific Railroad line runs along the southern border of the site. Deliveries to or from the proposed site could be accomplished by either rail or truck. Texas is located in the West South Central Demand Region for coal, which also includes Louisiana, Arkansas, and Oklahoma. According to the Energy Information Administration (EIA, 2000), the West South Central Demand Region receives the majority of its coal resources from the PRB and the Rockies. In 1997, the average distance that a coal shipment traveled to reach a destination in this region was about 1,300 miles (2,092 kilometers) (EIA, 2000). In terms of a straight-line distance, Odessa is approximately 1,250 miles (2,012 kilometers) from the Pittsburgh Coalbed (south-central Ohio in the northern Appalachian Basin), 900 miles (1,448 kilometers) from the Illinois Basin (southern Illinois), and 800 miles (1,287 kilometers) from the PRB (eastern Wyoming). While no sources of coal are available near the proposed plant site, Texas does have several coal mines in the eastern and southern portions of the state. The closest operating Texas coal mine is the Eagle Pass Mine, approximately 250 miles (402 kilometers) to the southwest of Odessa.

Source: FG Alliance, ***2006d*** (unless otherwise noted).

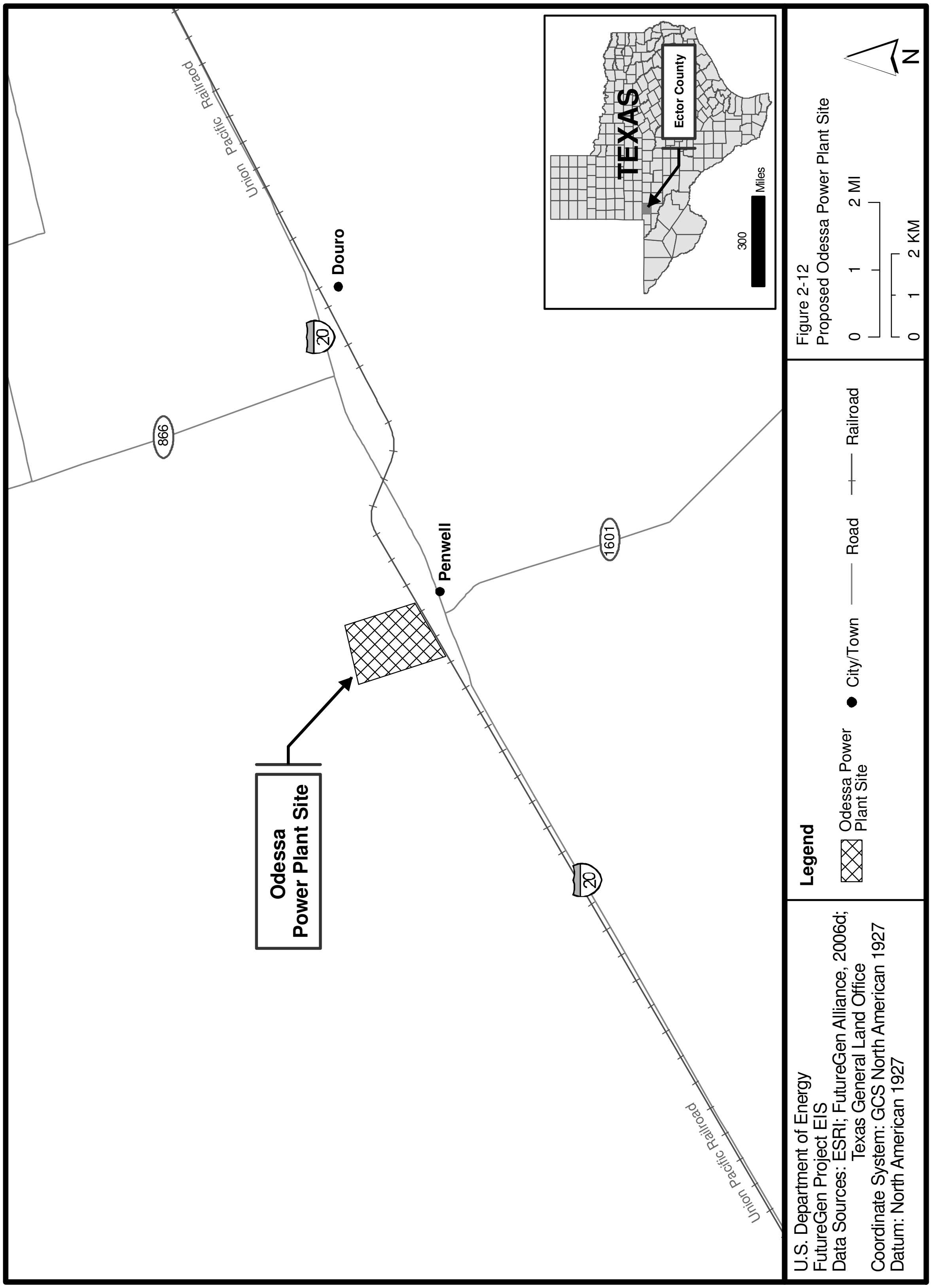


Figure 2-12
Proposed Odessa Power Plant Site

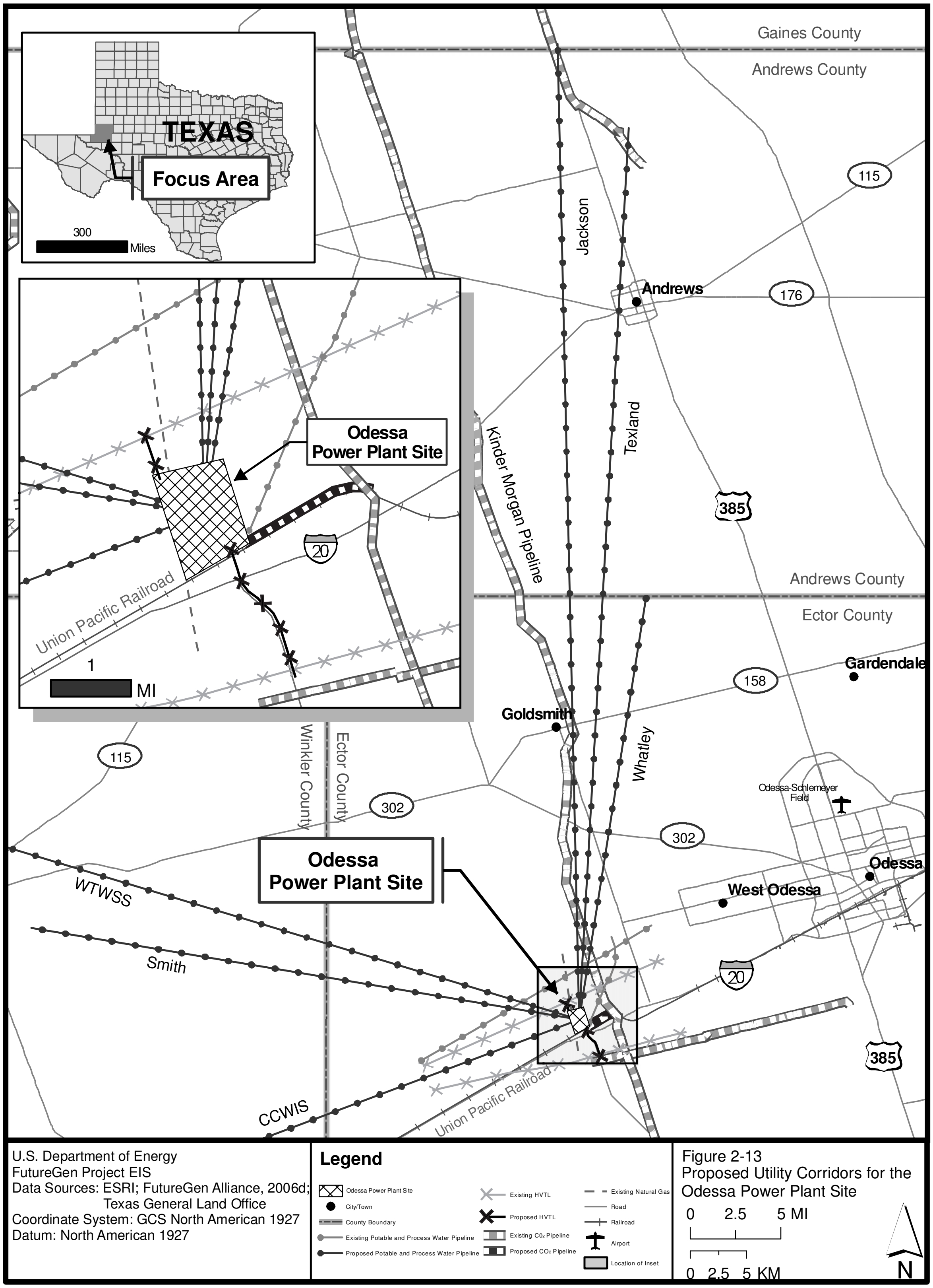


Figure 2-13
Proposed Utility Corridors for the Odessa Power Plant Site

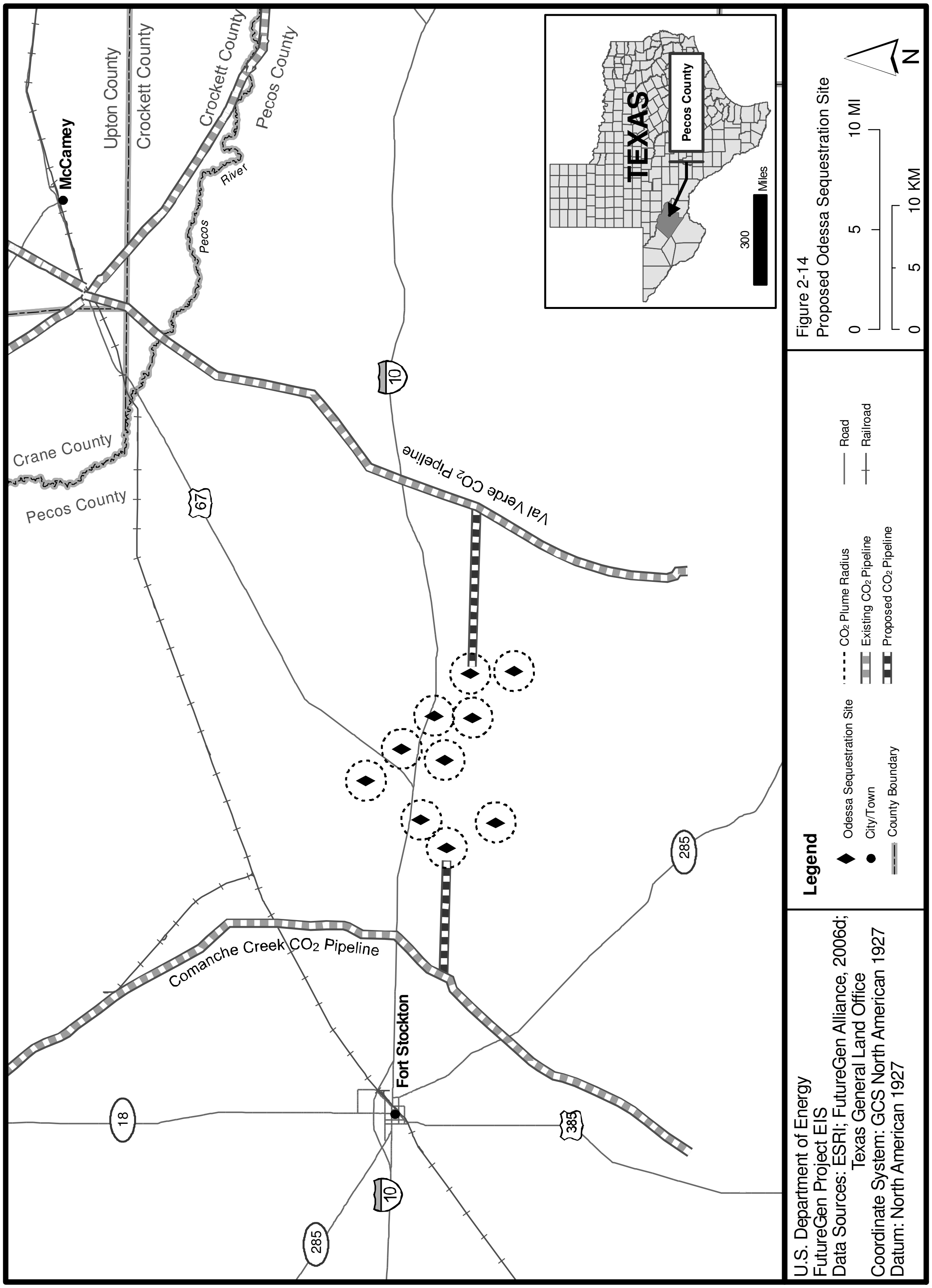


Figure 2-14
Proposed Odessa Sequestration Site

2.4.5 NEW OPTIONS FROM SITE PROPONENTS' BEST AND FINAL OFFERS

To complete the site proposal process, the Alliance offered an opportunity for the Site Proponents to submit Best and Final Offers (BAFOs) on their proposals. Pursuant to directions from the Alliance, the four candidate Site Proponents submitted BAFOs to the Alliance on August 1, 2007.

The Mattoon and Odessa Site Proponents provided additional water and CO_2 pipeline options for the Alliance to consider in its final siting decision. Neither the Tuscola nor Jewett Site Proponents put forward additional options for consideration that might have potential environmental impacts. Other information provided by the Site Proponents in their BAFO submissions relates solely to potential business arrangements between the Alliance and the Site Proponents.

The new Mattoon and Odessa options were not described in the Draft EIS. Nevertheless, as variations of the alternatives, DOE is considering their potential environmental consequences in this section of the EIS. The following additional options are considered reasonable for purposes of NEPA analysis.

2.4.5.1 Mattoon Process Water Pipeline

After issuance of the Draft EIS, a slight modification of the 6.2-mile (10.0-kilometer) process water pipeline was submitted to the Alliance by the Site Proponent (see Table S-1). As described in the Draft EIS, a 6.2-mile (10.0-kilometer) process water pipeline would be constructed, with all but 1 mile (1.6 kilometers) within an existing public ROW located within the city boundary. The new 1-mile (1.6-kilometer) corridor requiring new ROW would be constructed along the south side of a road. To avoid a potential land use conflict, however, Mattoon has obtained an easement for one parcel of land along the north side of the road, such that the process water pipeline would cross underneath the road at that property line and continue along the north side of the road for approximately 0.5 mile (0.8 kilometer), crossing back underneath the road to continue along the south side of the road as originally proposed. This slight modification of the process water pipeline alignment would have the same types and magnitudes of impacts as those described in this EIS.

2.4.5.2 Odessa Process Water Pipeline

Odessa has offered to provide raw or treated water from the City of Odessa's water treatment plant using a new, approximately 17-mile (27.4-kilometer), process water pipeline (see Figures S-A and 2-A). All but 1 mile (1.6 kilometers), approximately 5,000 feet (1,524 meters), of the distance of the new process water pipeline would either use existing public road ROWs (e.g., it would be installed under ground on the north side of 42nd Street) or be within the ROI analyzed in the Draft EIS for the Texland Great Plains water corridor. The new, less than 1-mile (1.6-kilometer) corridor requiring new ROW would traverse rangeland similar to that described for the Texland Great Plains water corridor.

The water supply would be from the City of Odessa which receives its raw water from the Colorado River Municipal Water District (CRMWD). The CRMWD is the legislatively created entity whose mission is to provide water to several communities in this region of Texas. The CRMWD currently owns and utilizes three reservoirs and four active well fields (the groundwater is typically used only during summer months to meet peak demands) (City of Odessa, 2007).

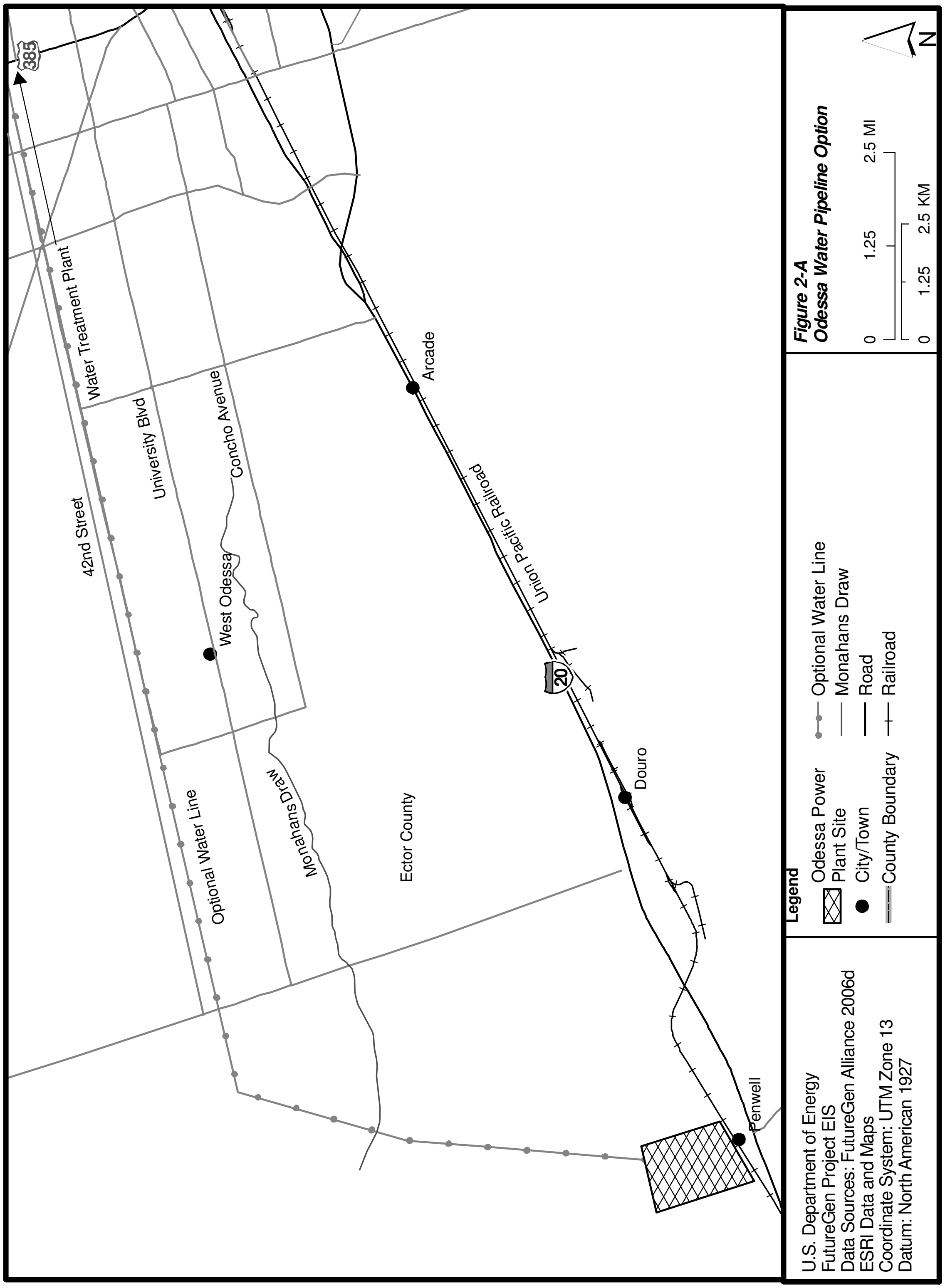


Figure 2-A
Odessa Water Pipeline Option

The CRMWD has sufficient excess supply to meet the FutureGen Project water demand. The CRMWD acquires surface water from three primary sources. The largest is the O.H. Ivie Reservoir in Concho County. Water from the O.H. Ivie Reservoir is delivered to the City of Odessa water treatment plant through a 60-inch (1.52-meter) diameter, approximately 157-mile (253-kilometer) pipeline (CRMWD, 2007). However, water from J.B. Thomas and E.V. Spence reservoirs can also be furnished to the City of Odessa water treatment plant.

The firm yield (maximum yield that can be delivered by the O.H. Ivie Reservoir even through a severe drought) is approximately 95,000 acre-feet per year (equivalent to 85 million gallons per day [MGD] or 320 million liters per day [MLD]). Major long-term contract users of this source include the City of Abilene, City of Midland, and City of San Angelo, whose combined contract amount is 45,000 acre-feet per year (equivalent to 40.1 MGD or 152 MLD) (TWDB, 2001a), which is less than half of the firm yield of the reservoir. The combined permitted diversion from the E.V. Spence and J.B. Thomas reservoirs is 3,000 acre-feet per year (equivalent to 2.7 MGD or 10 MLD) (TWDB, 2001b).

Groundwater is used in conjunction with CRMWD's surface reservoirs to meet customer demands during periods of low flow in surface waters. The CRMWD obtains groundwater from four active well fields: Ward County, Odessa, Snyder, and Martin. The largest well field is the Ward County field located near Monahans, about 25 miles (40 kilometers) west of the Odessa Site. This well field produces water from the Pecos aquifer, and consists of approximately 37 wells. Information on groundwater availability of the Pecos aquifer within Ector, Winkler, and Ward counties is provided in Section 7.6. This well field has a peak capacity of about 28 MGD (106 MLD). About 24 MGD (91 MLD) of this water can be delivered to the City of Odessa water treatment plant (CRMWD, 2007). The remaining three well fields are typically used as back-up or standby supplies.

The City of Odessa's water treatment plant has a peak capacity of approximately 50 MGD (189 MLD) for surface water and 20 MGD (76 MLD) for groundwater (City of Odessa, 2007). The City's peak daily demand is approximately 36.5 MGD (135 MLD). FutureGen would require 4.3 MGD (16.2 MLD), so that even during peak water demand, the City's water treatment plant would have adequate water and treatment capacity to supply water to the FutureGen Project (see Table 2-A and S-A).

Table 2-A. City of Odessa Water Supply and Treatment Capacity

Water Supply – O.H. Ivie Reservoir	*40.1 MGD (152 MLD)*
Water Supply – E.V. Spence and J.B. Thomas reservoirs	*2.7 MGD (10.2 MLD)*
Groundwater Supply – Ward County	*24.0 MGD (91 MLD)*
Total Available Water Supply	*0 MGD (253 MLD)*
Treatment Capacity	*70.0 MGD (265 MLD)*
Peak Daily Demand	*36.5 MGD (135 MLD)*
FutureGen Demand	*4.3 MGD (16.2 MLD)*
Peak Daily Demand with FutureGen	*40.8 MGD (154 MLD)*

Source: City of Odessa, 2007.

The original proposal and Section S.4.2.4, Table S-12, Sections S.10.3.3, 2.4.4, and 2.4.5, Table 3-3, and Chapter 7, stated that process water would be acquired by developing new well fields or from several existing well fields that draw water from different groundwater aquifers; up to 54 miles (86.9 kilometers) of new pipeline ROW would be required. The option to obtain process water from the City

of Odessa would require a shorter pipeline (of which about 60 percent would use existing ROW) and thus would likely have fewer impacts than the longer pipeline options that were described in the proposal (see Tables S-12 and 3-3). The new pipeline option would cross similar terrain as the pipeline options analyzed in the EIS for Odessa; therefore, impacts would be similar.

2.4.5.3 Odessa CO_2 Pipeline Options

The original proposal (and EIS sections identified in Sections S.4.2.4, 2.4.4, 2.4.5 and Chapter 7) stated that CO_2 would be transported (and co-mingled) in existing Kinder Morgan and PetroSource CO_2 pipelines leading to the injection site, with an approximately 2-mile (3.2-kilometer) CO_2 pipeline spur from the FutureGen plant to the existing Kinder Morgan CO_2 pipeline and 7- to 14-mile (11.3- to 22.5-kilometer) spurs from the existing PetroSource CO_2 pipelines to the injection well sites.

Odessa also offered two additional CO_2 pipeline options (see Figures 2-B, 2-C, S-B and S-C):

- ***Option 1 – Construction and operation of a new, approximately 90-mile (145-kilometer) dedicated pipeline from the FutureGen plant to the sequestration site along existing ROWs (Figures 2-B and S-B); and,***
- ***Option 2 – Use of the existing pipeline owned by Kinder Morgan CO_2 Company and the construction and operation of a new, approximately 30-mile (48-kilometer) dedicated pipeline (ranging from 6 to 12 inches [15.2 to 30.5 centimeters] in diameter) from the end of the Kinder Morgan line (near McCamey, Texas) to the injection well sites (Figures 2-Cand S-C). Option 2 would require additional sulfur removal either at the FutureGen plant or in a separate sulfur removal plant operated by Kinder Morgan.***

Odessa originally proposed an option for transporting CO_2 in the existing Kinder Morgan CO_2 pipeline along with PetroSource's existing Val Verde pipeline and PetroSource's existing (but not currently operating) Comanche Creek pipeline that runs to the east side and the west side, respectively, of the proposed sequestration site. However, the existing Val Verde CO_2 pipeline, which runs to the east of the proposed sequestration site, could not be used to transport FutureGen CO_2 to the proposed sequestration site. The Val Verde pipeline carries CO_2 northwards, rather than southwards as would be required for the original proposal. Given PetroSource's current use of the Val Verde pipeline to carry CO_2 northwards, it would be infeasible to use this line to transport FutureGen CO_2 southwards to the proposed injection site.

Use of the existing Comanche Creek pipeline would require upgrades such as repairing or replacing sections of the pipeline or pipeline components. In addition, normal pipeline safety analysis and leak testing, similar to that conducted for new pipelines, would be required and conducted along the length of the pipeline. DOE calculations show that the existing Comanche Creek 6-inch (15.2-centimeter) pipeline would be sufficient to transport a maximum of about 1.1 million tons (1 MMT) of CO_2 per year, although two booster pumps would need to be installed about 25 miles (40 kilometers) apart along the line to maintain pressure (FG Alliance, 2007a). Power for the pumps would be supplied from two existing 69-kV transmission lines that intersect the Comanche Creek pipeline and substations that are located near the pipeline. Up to 10 miles (16 kilometers) of distribution lines from the substations to the pumps may be required. The pumps would likely be housed in a small shed (similar to a backyard shed, approximately 150 square feet [14 square meters]) which would contain the pump, controller, and electrical switchgear. The pump shed would be fenced and placed within the existing pipeline ROW.

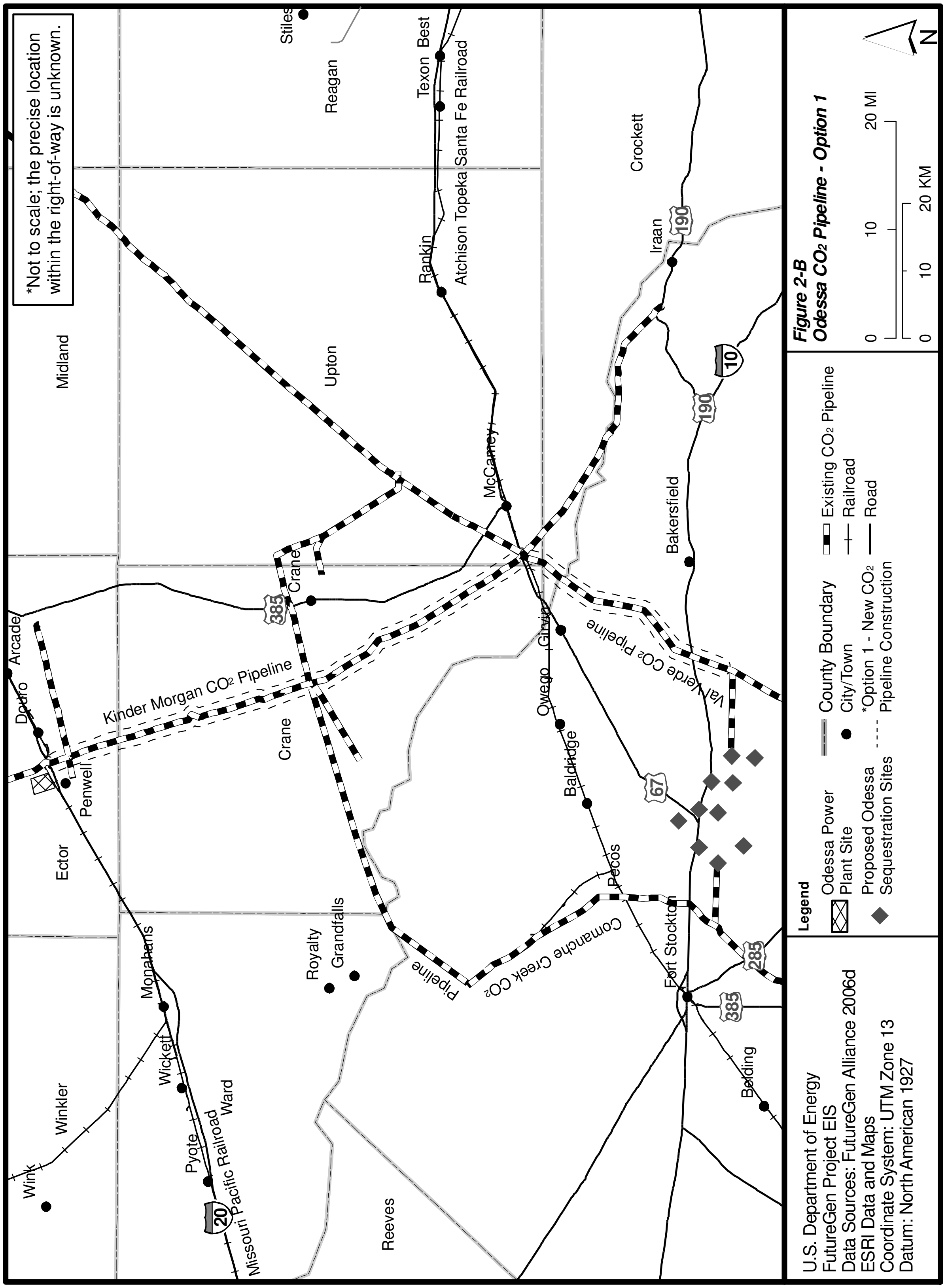


Figure 2-B
Odessa CO_2 Pipeline - Option 1

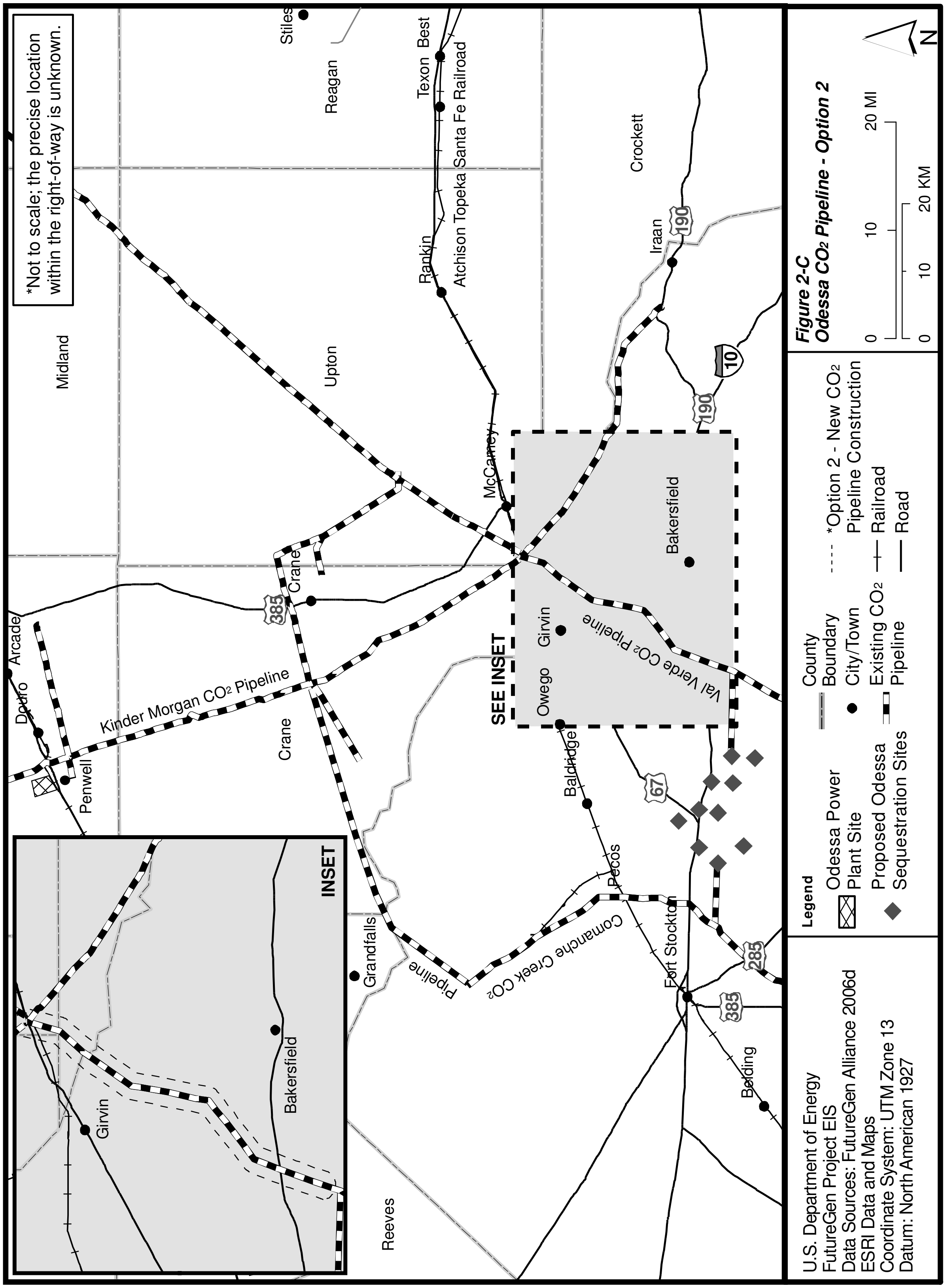


Figure 2-C
Odessa CO_2 Pipeline - Option 2

Any new CO_2 pipelines would be constructed and operated by either Kinder Morgan CO_2 Company, Occidental Petroleum Corporation, PetroSource, or Trinity CO_2 LLC and would follow existing ROWs (short CO_2 pipeline spurs from the power plant site to the existing Kinder Morgan pipeline and from existing PetroSource CO_2 pipelines to the sequestration site were addressed in the EIS). Obtaining new pipeline ROW is a common occurrence in West Texas. The construction and operation of new CO_2 pipelines is not expected to have environmental impacts of a different nature, in addition to what has already been forecasted in the EIS because construction would occur within existing ROW and would traverse similar terrain as was analyzed in the EIS for the original proposal.

To use the existing Kinder Morgan CO_2 pipeline for Option 2 and the original proposal, additional sulfur would need to be removed from the CO_2 stream. If this option were to be selected, it would be likely that the FutureGen plant would be designed to provide for an additional scrubbing column to the Acid Gas Removal Unit and to increase the recirculation rate of the scrubbing solvent. No additional water treatment chemicals would be required for this additional column; the volume of elemental sulfur created by this process would increase by less than 3 percent over that which was described in the original proposal. For these reasons, no additional environmental impacts would be expected beyond those described in Section 7.16. If Kinder Morgan were to construct and operate a sulfur removal plant at the FutureGen power plant site (i.e., not part of the FutureGen plant), it would likely use solid metal oxide adsorbents in fixed beds to remove the sulfur from the CO_2.

For the removal of sulfur, there are a broad range of technologies available including guardbeds or molecular sieves. Byproduct generation and waste streams would likely be minimal and could be integrated with those from FutureGen operations and byproducts would be minimized. Potential byproducts include those similar to that from the FutureGen Claus plant (analyzed in this EIS) and perhaps zinc oxide if a guardbed is utilized. Where possible, adsorbent materials would be regenerated and byproducts and wastes minimized. Due to the relatively small amount of hydrogen sulfide in the feed stream (<100 parts per million [ppm]), waste quantities would be minimal compared to that in the power plant.

Odessa also proposed as an option "CO_2 swapping." Through this option, CO_2 generated by a FutureGen plant located in Odessa would be directed into the CO_2 pipeline owned by Kinder Morgan CO_2 Company where it would be transported and sold for enhanced oil recovery (EOR). CO_2 separated by natural gas processing plants located south of the proposed Odessa injection site would be transported northwards through the PetroSource Val Verde CO_2 pipeline and injected at the proposed Odessa injection site. Thus, while the goal for injection and storage of the CO_2 could be met, no CO_2 from the FutureGen plant would reach the injection site under this option. Both DOE and the Alliance have determined that this option would not meet one of the key purposes of the FutureGen project, which is to demonstrate the integration of a coal-fueled power plant with CO_2 capture and sequestration. For this reason, DOE has determined that this option is unreasonable and has eliminated it from further consideration in this EIS.

2.4.5.4 Potential Impacts of Proposed Odessa Pipeline Route Options

The affected environment and environmental impacts from construction of the new Odessa water and CO_2 pipeline options were assessed by evaluating several sources. These sources include review of aerial photographs (2005) and topographic maps (2005) for the area; the National Hydrology Dataset from the United States Geologic Survey (1999) for water bodies, streams/washes, and springs; the Texas Parks and Wildlife Department (2003) for vegetation; Soil Data Mart via the United States Department of Agriculture, Natural Resources Conservation Service for Soils (2007); National Wetland Inventory

(NWI) data for wetlands (2002); and ESRI Data and Maps (2005) for Census and traffic and transportation information.

The new Odessa water and CO_2 pipeline options would not require changes to sections of the EIS that address potential impacts to resources as there were no impacts from the construction or operations of the new pipelines options, under the following topical headings: Climate and Meteorology, Geology, Community Services, Socioeconomics, and Environmental Justice.

Table 2-B briefly describes the potential impacts associated with the new Odessa water and CO_2 pipeline options presented in the BAFO.

Table 2-B. Potential Impacts Associated with the New Odessa Process Water Pipeline and CO_2 Pipeline Options

Resource Area	***Relevance to the Potential Environmental Impacts***
New Odessa Water Pipeline Option	
Air Quality, Soils, Biological, Transportation and Traffic, and Noise and Vibration	***Under the new water pipeline option, impacts associated with these resource areas would be temporary, occurring during the construction phase and reduced or mitigated through best management practices (BMPs) discussed in Section 3.4, Table 3-13, and Table 3-14.*** ***Under Air Quality, emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), carbon monoxide (CO), and volatile organic compounds (VOCs) from construction would be localized and temporary in nature and could cause minor to moderate short-term degradation of air quality in areas where pipeline construction is taking place.*** ***Soils would be temporarily disturbed during construction. No prime farmland soils were found in the vicinity of the proposed water pipeline.*** ***Wildlife species found along this corridor could be temporarily displaced during construction, but the land above the pipeline would be revegetated with native species after construction, maintaining wildlife habitat similar to current conditions.*** ***Minor disruptions to traffic could occur along one major and 47 minor roads during construction but would not create a substantial direct impact or long-term impact to traffic operations.*** ***Sensitive receptors in the vicinity of construction areas would temporarily experience elevated noise levels; however, such impacts would be minimal. Based on available data, 12 churches and 5 schools are located within a 1-mile (1.6-kilometer) ROI of the proposed water pipeline route.***
Groundwater (Use)	***Under this option, the CRMWD would supply water. The CRMWD currently owns and utilizes three reservoirs and four active well fields. Groundwater would only be used during the summer months to meet peak demands. Impacts to groundwater availability would be minimal as discussed in Section S.4.3.2.***
Surface Water (Use)	***Under this option, water would be required during construction for dust suppression and equipment washdown, and would most likely be trucked to areas where needed; no water would be withdrawn from local surface waters. Construction of the pipeline would disturb land along the water pipeline corridor, which could cause temporary indirect impacts to adjacent surface waters (for example, Monahans Draw) such as sedimentation and surface water turbidity from runoff. Impacts to surface water availability would be negligible as discussed in Section S.4.3.2.***

Table 2-B. Potential Impacts Associated with the New Odessa Process Water Pipeline and CO_2 Pipeline Options

Resource Area	Relevance to the Potential Environmental Impacts
Wetlands and Floodplains	***NWI mapping indicates that at least one intermittent palustrine wetland (less than 8 acres [3.2 hectares]) located along the proposed water pipeline may be impacted under this option. Field verification would be required to confirm NWI mapping and to determine if any additional wetlands are present, and if so, the value of any wetlands occurring along the corridor. Any impacts would be reduced or mitigated through BMPs discussed in Section 3.4, Table 3-13, and Table 3-14. The alignment of the water pipeline could be modified to avoid the wetland or construction could be modified to reduce potential impacts.*** ***Based on available floodplain information, floodplains are present along the Odessa water pipeline option. However, temporarily adding or excavating fill during construction within the floodplain would have no permanent impact on the lateral extent, depth, or duration of flooding in the floodplain areas traversed. Any temporary impacts would be reduced or mitigated through BMPs discussed in Section 3.4, Table 3-13, and Table 3-14.***
Cultural Resources	***Within the ROI for the Odessa Site, the potential exists for cultural resources to be present. A Phase I survey would be needed to identify if any cultural resources exist along the water pipeline route, after the exact position of the route has been identified.***
Land Use	***Under this option, construction of the approximately 17-mile (27.6-kilometer) proposed water pipeline would have temporary, minor effects on land use during construction due to trenching, equipment movement, and material laydown. The ability to use some lands for their existing uses would be temporarily lost during construction. However, where the pipeline would be constructed in the existing ROW, long-term land use would not change. Where new ROW would be acquired, it is not anticipated that long-term land use would change, because this land is used as range land. The new, less than 1-mile (1.6-kilometer) section of the corridor would be within the same land use type as that found in the Texland corridor ROI.***
Materials and Waste Management	***Clearing of vegetation and grading during construction may create land debris that would require removal from the site. Construction debris disposal capacity is available at area landfills.*** ***Construction equipment would require fuel, oils, lubricants, and coolants. Should any of these require disposal, they would be appropriately managed and disposed of by the construction contractor.*** ***During normal operation, the water pipeline would not require additional materials and would not generate waste, other than cleared vegetation, if necessary, that could be disposed of at a non-hazardous waste landfill.***
Utility Systems	***No current information on utilities was available for the proposed water pipeline option. However, there is a potential for temporary impacts to underground utilities during construction.***

Table 2-B. Potential Impacts Associated with the New Odessa Process Water Pipeline and CO_2 Pipeline Options

Resource Area	*Relevance to the Potential Environmental Impacts*
New Odessa CO_2 Pipeline Options	
Air Quality, Soils, Biological, Transportation and Traffic, and Noise and Vibration	***Under the new CO_2 pipeline Options 1 and 2, impacts associated with these resource areas would be temporary, occurring during the construction phase and reduced or mitigated through BMPs discussed in Section 3.4, Table 3-13, and Table 3-14.*** ***Under Air Quality, emissions of SO_2, NO_X, PM, CO, and VOCs from construction of Options 1 or 2 would be localized and temporary in nature and could cause minor to moderate short-term degradation of air quality in areas where construction is taking place.*** ***Soils would be temporarily disturbed during construction of pipeline Options 1 and 2. According to available data, no prime farmland soils were found in Crane, Crockett, or Ector counties. Prime farmland soils were found in Pecos County. However, it was not possible to determine if these soils are in the vicinity of the proposed new CO_2 pipelines based on available data.*** ***Wildlife species found along this corridor could be temporarily displaced during construction of pipeline Options 1 and 2. However, the land above the pipeline would be revegetated with native species after construction, maintaining wildlife habitat similar to current conditions.*** ***Minor disruptions to traffic could occur along up to 4 major and 119 minor roads during construction of pipeline Options 1 and 2, but would not create a substantial direct impact to traffic operations.*** ***Based on available data, no churches or schools were found adjacent to Options 1 and 2. Any additional sensitive receptors in the vicinity of construction areas would temporarily experience elevated noise levels; however, such impacts would be minimal.***
Wetlands and Floodplains	***An analysis of NWI maps indicates that 20 palustrine wetlands and 1 riverine wetland occur within the ROI near where the pipeline would cross the Pecos River for both Options 1 and 2. The palustrine wetlands range from 0.10 to 3.2 acres (0.04 to 1.3 hectares) in size, for a total of 15.9 acres (6.4 hectares). The size of the riverine wetland is not known, but potentially encompasses the whole length of the Pecos River segment within the ROI. These wetlands are directly associated with the Pecos River and nearby meander cutoffs formed by the river over time. After the precise pipeline location is determined, field verification would be required to determine if any jurisdictional wetlands are present and, if so, the value of the wetlands. Any impacts that could not be avoided by repositioning the pipeline location would be reduced or mitigated through BMPs discussed in Section 3.4, Table 3-13, and Table 3-14. If wetlands are present, the alignment of the pipeline could be modified to avoid the wetland or construction could be modified to reduce potential impacts.*** ***Based on available floodplain information, floodplains are present along the CO_2 pipeline for Options 1 and 2. However, temporarily adding or excavating fill during construction within the floodplain would have no permanent impact on the lateral extent, depth, or duration of flooding in the floodplain areas traversed. Any temporary impacts would be reduced or mitigated through BMPs discussed in Section 3.4, Table 3-13, and Table 3-14.***

Table 2-B. Potential Impacts Associated with the New Odessa Process Water Pipeline and CO_2 Pipeline Options

Resource Area	*Relevance to the Potential Environmental Impacts*
Surface Water	***In both Options 1 and 2, the pipeline would cross the upper Pecos River (Segment 2311) near where the western tip of Crockett County meets Crane and Pecos counties. This segment was listed as impaired in the 2006 Texas Commission on Environmental Quality (TCEQ) 303(d) list due to depressed oxygen levels. Sediment loading is another concern for the Pecos River. Careful planning would be needed to minimize sediment impacts to the Pecos River during construction activities. [Reference: Draft Watershed Protection Plan for the Pecos River in Texas, Texas State Soil and Water Conservation Board http://pecosbasin.tamu.edu/wpp.php.***
Cultural Resources	***Within the ROI for the Odessa Site, the potential exists for cultural resources to be present. A Phase I survey would be needed to identify if any cultural resources exist along the proposed CO_2 pipeline for Options 1 and 2, after the exact position of the route has been identified.***
Land Use	***Under pipeline Options 1 and 2, construction of the CO_2 pipeline would have temporary, minor effects on land use during construction due to trenching, equipment movement, and material laydown. The ability to use some lands for their existing uses would be temporarily lost during construction. However, because the pipeline would be constructed in the existing ROW, long-term land use would not change.***
Aesthetics	***Under pipeline Option 2, the potential exists for visual impacts to receptors and travelers as a result of the sulfur removal plant at the FutureGen Power Plant or another location (currently unknown). Additionally, two booster pumps would be located somewhere along the CO_2 pipeline.***
Utility Systems	***No current information on utilities was available for the new CO_2 pipelines. However, there is a potential for temporary impacts to underground utilities during construction.***
Materials and Waste Management	***Clearing of vegetation and grading during construction may create land debris that would require removal from the site. Construction debris disposal capacity is available at area landfills.*** ***Construction equipment would require fuel, oils, lubricants, and coolants. Should any of these fluids require disposal, they would be appropriately managed and disposed of by the construction contractor.*** ***During normal operation, the CO_2 pipeline would not require additional materials and would not generate waste, other than cleared vegetation, if necessary, that could be disposed of at a non-hazardous waste landfill.*** ***For the removal of sulfur, there are a broad range of technologies available including guardbeds or molecular sieves. Byproduct generation and waste streams would likely be minimal and could be handled along with those from FutureGen operations. Potential byproducts include those similar to that from the Claus plant and perhaps zinc oxide if a guardbed is utilized. Where possible, adsorbent materials would be regenerated and byproducts/wastes minimized. Due to the relatively small amount of hydrogen sulfide in the feed stream (<100 ppm), waste quantities would be minimal compared to that in the power plant.***

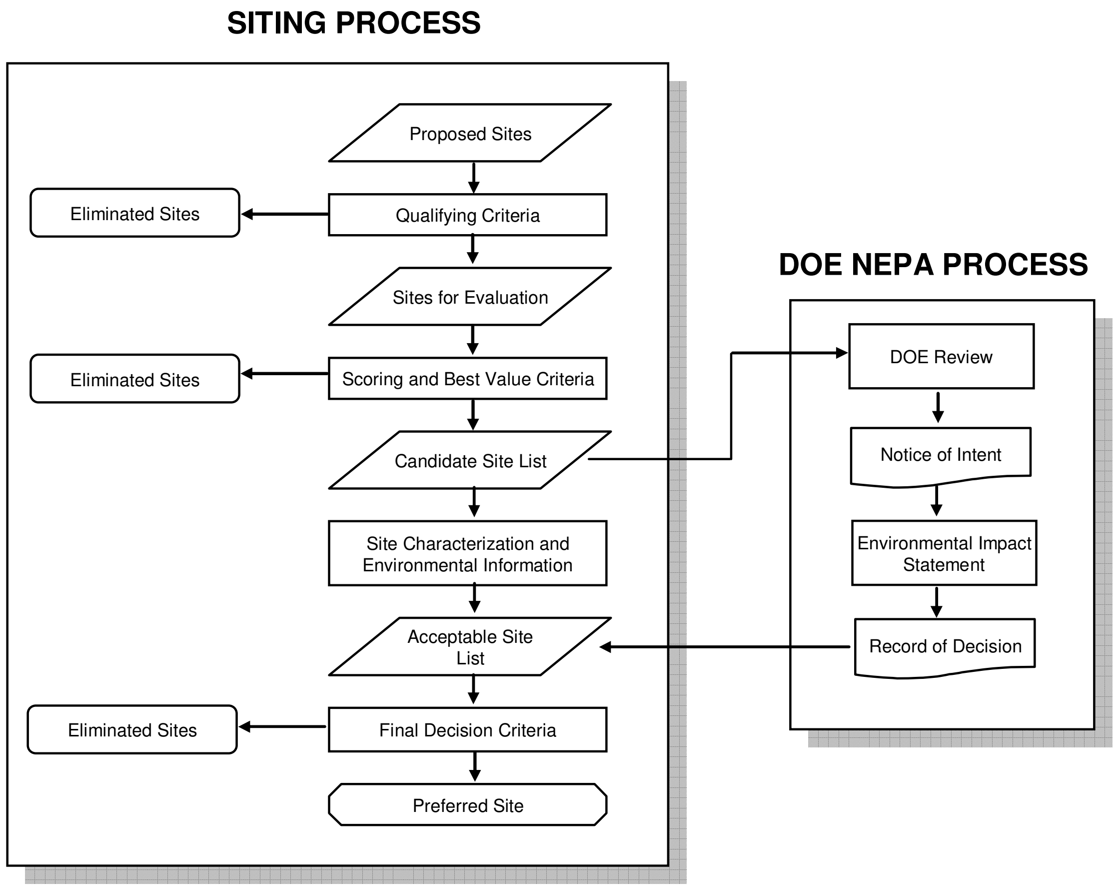
Table 2-B. Potential Impacts Associated with the New Odessa Process Water Pipeline and CO_2 Pipeline Options

Resource Area	*Relevance to the Potential Environmental Impacts*
Health and Safety	***Potential occupational health and safety risks during construction of the proposed new CO_2 pipelines are expected to be typical of the risks for this type of construction. Health and safety concerns include: the movement of heavy objects, including construction equipment; slips; trips; and falls; and the risk of fire or explosion from general construction activities. For the two options, the risks of construction accidents would be primarily a function pipeline length, assuming most other factors would be the same per unit length of pipeline for the two options. Option 1 (having three times greater new pipeline length than Option 2) presents about three times greater risks of construction accidents compared to Option 2. Both Options 1 and 2 would present several times greater risks than the construction of only the connector pipelines (from the power plant to the existing pipeline system and from the existing pipelines to the sequestration site) for the original option.*** ***The potential for an accidental release (i.e., puncture or rupture) to occur on a newly constructed CO_2 pipeline would be the same, per mile of pipeline, as that analyzed in the EIS and in the Risk Assessment. Assuming the spacing of emergency shut-off valves is the same for all options (5-mile [8-kilometer] spacing), the quantity of gas that could be released varies as a function of the inside diameter of the pipeline (ignoring small differences caused by small differences in pressure). If a new pipeline segment is built between McCamey station and the sequestration site, the use of a larger pipe diameter, such as 12 inches (30.5 centimeters) (e.g., Options 1 and 2) instead of 6 inches (15.2 centimeters) (e.g., original option, using the Comanche Creek pipeline), results in the potential release of a much larger quantity of gas (potentially 4 times as much) on this segment, compared to the original option using the Comanche Creek pipeline, unless the spacing of emergency shut-off valves is different.*** ***The Risk Assessment and this EIS present the analysis of a hypothetical 12.8 inch (32.5 centimeters) inside-diameter pipeline with a length of 61.5 miles (99 kilometers) located along a straight path from the proposed power plant site to the middle of the proposed sequestration site. This differs from Option 1 in that the pipeline length is about 30 percent less and in that the location is different. However, the terrain traversed (range land and arid lands) and the population densities within the region of potential effects (up to about 14,000 feet [4,267 meters] from the pipeline for adverse effects from hydrogen sulfide (H_2S) exposure after a pipeline rupture) are approximately the same. Population density (receptors) in the area surrounding the hypothetical straight-line pipeline route was examined in the Risk Assessment, and the population density is very low, representing the fact that this route traverses remote arid areas where few people live and where livestock density and wildlife densities are low. The proposed pipeline options likewise traverse remote arid areas of low population densities. The nearest town, Girvin, is outside the region of potential effects (more than 14,000 feet [4,267 meters] from the proposed pipeline routes).*** ***Including the use of existing pipelines for Option 2 and for the original option, all three options have approximately the same level of risks and potential impacts. A notable difference is that where a new pipeline would be constructed parallel to an existing pipeline and within the ROW of the existing pipeline, there would be a small risk of both pipelines being punctured or ruptured in the same accident. This risk would be much smaller than the risk of a single pipeline puncture or rupture, as presented in the Risk Assessment. Given the conceptual level information provided in the BAFOs, the Risk Assessment adequately addresses the magnitude and types of risks and potential impacts associated with the proposed project, given any one of the new pipeline options. The risks would remain small under any of the options.***

2.4.6 ALTERNATIVES ELIMINATED FROM FURTHER CONSIDERATION

2.4.6.1 Site Selection Process

On December 2, 2005, the Alliance entered into a Limited Scope Cooperative Agreement with DOE for the Alliance to begin the site selection process and prepare a conceptual design for the proposed FutureGen Project. The Alliance developed siting criteria, issued a Request for Proposals (RFP), evaluated proposals received, and visited each proposed site. DOE reviewed Alliance activities at each step in the process to ensure fairness, openness, and technical accuracy. DOE also reviewed the process at each step to ensure that all reasonable alternative sites would be evaluated by DOE in the NEPA process. Figure 2-15 shows an overview of the siting process, which is discussed in detail below.



Source: Adapted from FG Alliance, 2006a

Figure 2-15. Alliance Siting Process

2.4.6.2 Siting Criteria

Beginning in December 2005, the Alliance Siting Team developed criteria to select sites that could be considered for the FutureGen Project. This Siting Team consisted of scientists, engineers, and others who are either employees of the Alliance member companies, consultants to the Alliance, members of Technical Committees, or employees of Battelle Memorial Institute, the primary support contractor for the Alliance. The Technical Committees are advisory groups of experts, such as distinguished industry consultants, members of academia, employees of national laboratories, and representatives of industry-related organizations. The criteria, which were reviewed and approved by DOE, focused on the goals and objectives for the FutureGen Project, including the need to expeditiously demonstrate a viable CO_2 capture and geologic storage process that would address an issue of national and international importance. In particular, the Siting Team drafted criteria to identify and avoid potential technical, engineering, and environmental challenges that could affect the schedule and success of the FutureGen Project.

Three types of criteria were established:

- Qualifying criteria – Criteria that each site would have to meet before being considered further - failure to meet any criterion resulted in disqualification;
- Scoring criteria – Criteria that would allow sites to be ranked based on the extent to which they possessed desirable features; and
- Best value criteria – Criteria that were not capable of being quantitatively scored, but that represented factors the Alliance would consider when choosing a site that could best fulfill the Project's mission.

The Alliance developed criteria for both the power plant (surface) and geologic storage (subsurface) components and later revised these criteria based on comments from subject-matter experts. The Alliance also sought, received, and considered input from outside stakeholders, including regulatory agencies and environmental groups, through selected interviews and comments received during the formal public comment period. DOE reviewed the rationale and participated in meetings to discuss each criterion before the Alliance published the draft RFP for public comment. The criteria are found in the FutureGen Alliance *Request for Proposals for the FutureGen Facility Host Site* (http://www.futuregenalliance.org/news/futuregen_siting_final_rfp_3-07-2006.pdf) (FG Alliance, 2006a) and in the *Results of Site Offeror Proposal Evaluation* report ***(http://www.futuregenalliance.org/publications/fg_proposal_evaluation_report.pdf)*** dated July 21, 2006 (FG Alliance, 2006a).

2.4.6.3 Request for Proposal

The qualifying, scoring, and best value criteria were included in a draft RFP that the Alliance posted to its website (FG Alliance, 2006f) on February 14, 2006, for public review and comment. The Alliance accepted comments regarding the draft RFP until February 28, 2006. Responses to the comments received were posted to the website. The final RFP, revised in accordance with comments received and other considerations, was posted to the Alliance website on March 7, 2006. The Alliance accepted clarifying questions regarding the final RFP until March 16, 2006. Responses to questions received were posted to the website and, in response to the clarifying questions, minor amendments to the final RFP were posted to the website on March 20 and 24, 2006. The final RFP stated that the deadline for proposal submittals was May 4, 2006.

2.4.6.4 Site Proposals Received

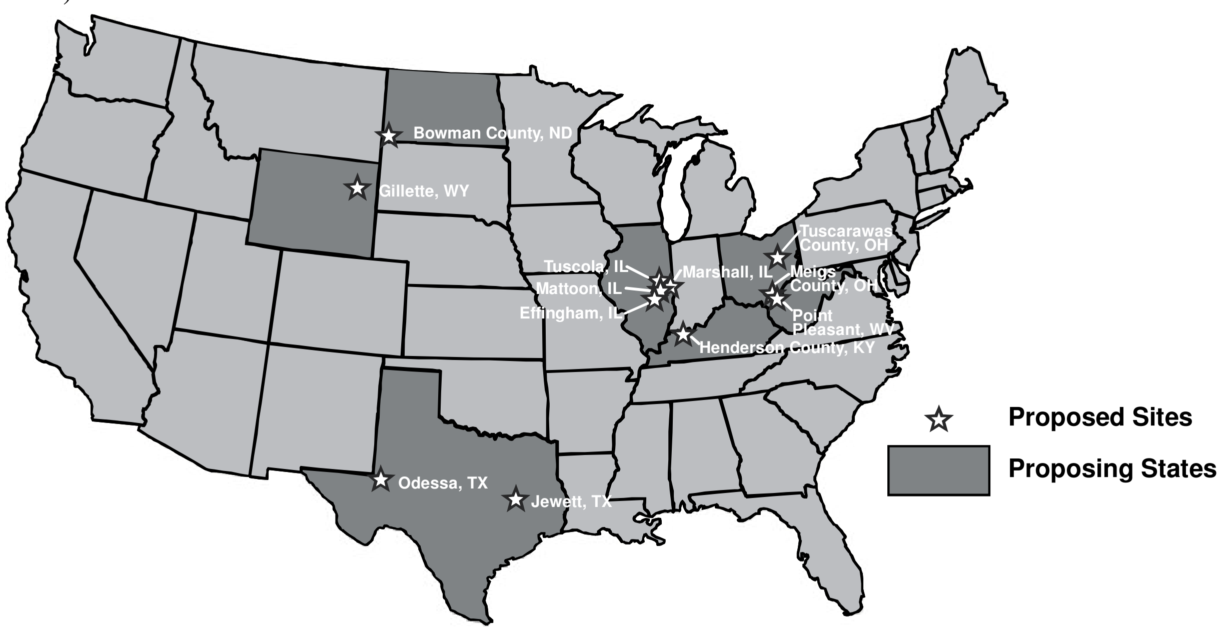
The Alliance received 12 proposals from seven states (see Figure 2-16). The proposals included[1]:

- Illinois – Effingham Site
- Illinois – Marshall Site
- Illinois – Mattoon Site
- Illinois – Tuscola Site
- Kentucky – Henderson County Site
- North Dakota – Bowman County Site
- Ohio – Meigs County Site
- Ohio – Tuscarawas County Site
- Texas – Jewett Site
- Texas – Odessa Site
- West Virginia – Point Pleasant Site
- Wyoming – Gillette Site

After an initial review of the 12 proposals, the Alliance visited each site to verify that the proposals fairly represented the condition at the site.

2.4.6.5 Proposal Evaluation

The Alliance Siting Team created two Proposal Evaluation Teams. One team evaluated the proposals based on criteria related to the power plant site, and the other team evaluated the proposals based on criteria related to geologic storage. Both Proposal Evaluation Teams included outside experts. Three outside experts from Sargent & Lundy, L.L.C. assisted with the evaluation of the power plant site proposals. Two outside experts from Lawrence Berkeley National Laboratory and Montana State University assisted with the evaluation of the geologic storage portion of the proposals (FG Alliance, 2006a).



Source: FG Alliance, 2006a

Figure 2-16. Map of Offered Sites

[1] Some site offerors submitted proposals under different titles than shown above. For example, the Jewett Site was submitted for consideration under the title "Heart of Brazos" because it is located within the jurisdiction of both the Heart of Texas and the Brazos Valley Councils of Government. In addition, the Illinois sites (Mattoon and Tuscola) included the landowner's last name as part of the site name (i.e., Mattoon-Dole and Tuscola-Pflum). For consistency within this EIS, all alternative site locations will be referred to according to the name of the closest city.

2.4.6.6 Qualifying Criteria Review

The Evaluation Teams carefully examined each proposal to assess compliance with qualifying criteria. During this review, the Alliance generated clarifying questions for each of the site offerors. The questions were submitted to individual offerors on May 18, 2006, by e-mail. All offerors submitted their responses by the deadline of May 24, 2006 (the original deadline of May 23 was extended by one day at the request of one offeror). After review of the responses to questions, as well as the original proposals, the Evaluation Teams determined that four sites did not satisfy all of the qualifying criteria. The Alliance Board of Directors reviewed this conclusion during conference calls on May 24 and May 30, 2006. After thorough discussions, the Board concurred with the Evaluation Team's conclusions and voted to exclude the four sites from further consideration in the proposal evaluation process.

The four sites that did not meet all of the qualifying criteria were:

- North Dakota – Bowman County Site
- Ohio – Meigs County Site
- West Virginia – Point Pleasant Site
- Wyoming – Gillette Site

Some sites did not qualify based on more than one criterion. The reasons for excluding these four sites were:

- One site was located within 60 miles (96.6 kilometers) of the boundary of a Mandatory Class I Visibility Area. Minimizing or avoiding environmental impacts is a major mission of the FutureGen Project. The 60-mile (96.6-kilometer) distance was selected based on Prevention of Significant Deterioration (PSD) requirements that discourages siting a source of air pollutant emissions within 60 miles (96.6 kilometers) of a Class I visibility area, and the 60-mile (96.6-kilometer) buffer is based on standard industry practice.
- Two sites proposed CO_2 injection wells that would be less than 10 miles (16.1 kilometers) from public access areas (defined as a state park or national park or preserve, national monument, national seashore, national lakeshore, national wildlife refuge, designated wilderness area, designated wild and scenic river, or study area for any of the preceding designations) or sensitive features such as large dams, water reservoirs, hazardous materials storage facilities, and Class I injection wells. Based on the professional judgment of technical experts, the Alliance concluded that a 55-million-ton (50 MMT) CO_2 plume would have a very low probability of migrating 10 miles (16 kilometers) or more from the bottom hole of an injection well. Because this would be a first-of-a-kind demonstration project, 10 miles (16 kilometers) was selected as a conservative safe distance.
- One site had a public access road and a railroad traversing it and thus did not meet the minimum 200 contiguous-acres (81 contiguous-hectares) site requirement. The Alliance based this minimum acreage requirement on the area required for typical power plants, while taking into account the FutureGen Project's need for additional space for multiple coal piles, research facilities, and carbon capture facilities.
- The proposed sequestration reservoir for one site met the definition of an underground source of drinking water because it was specified as having fewer than 0.08 pound ***per*** gallon (10,000 milligrams ***per*** liter) total dissolved solids. This criterion was designed to protect current and future sources of drinking water.

2.4.6.7 Scoring Criteria Review

For the remaining eight sites that met all qualifying criteria (qualifying sites), each team member individually scored each proposal using the scoring criteria, scales and weights established in advance of the receipt of the proposals. Each Evaluation Team then conferred and identified areas of difference for further discussion and resolution.

During the period of June 6 through 8, 2006, all Evaluation Team members, including the outside technical experts, met in Richland, Washington, for an internal workshop with members of the Alliance Technical Committee observing the meeting. During this meeting, the Evaluation Team developed and submitted a set of clarifying questions for one site offeror (Illinois-Marshall), and a response was received by the June 12, 2006, deadline set by the Alliance.

The scores for each site were tabulated and a final score was derived for each scoring criterion for each site. Ranked lists of sites for both the power plant and the geologic storage area were generated and combined to develop a ranked list of qualified sites. The summaries for this scoring process are found in the FutureGen Alliance report *Results of Site Offeror Proposal Evaluation* dated July 21, 2006 (FG Alliance, 2006a).

Site visits were conducted in late May 2006. A Site Visit Team made inquiries in the following areas regarding each proposed site during the site visit:

- Coal supply environment/delivery mode flexibility
- Road access
- Distance to rail/barge delivery
- Access to natural gas pipeline
- Cultural resources
- Air dispersion
- Grid proximity
- ROW
- Voltage
- Proximity to public access areas
- Proximity to Tribal lands
- Proximity to proposed target formation(s)
- Physical access to area above geologic storage (e.g., roads)
- Presence of mines, landfills, wells above geologic storage area
- Sensitive receptors over geologic storage area
- Background CO_2 sources

The Site Visit Team presented the results of the site visits to the Proposal Evaluation Teams and members of the Alliance Technical Committee during the Richland internal workshop. The site visits confirmed the information in the proposals, identified some additional information, and were used to inform the Alliance's consideration of the proposals.

2.4.6.8 Best Value Criteria Review

The RFP asked site offerors to submit a narrative discussion regarding several best value criteria. These criteria relate to:

- Land cost
- Availability/quality of existing plant and target formation characterization data
- Land ownership
- Residences or sensitive receptors above target formation
- CO_2 title and indemnification
- Market for H_2
- Waste recycling and disposal
- Clean Air Act compliance
- Expedited permitting
- Transmission interconnection
- Background CO_2 data
- Power sales
- Other considerations

The responses provided by the site offerors to the best value criteria were summarized and compared. The Alliance Board of Directors reviewed this material and used it, along with the scoring results, to develop the Candidate Site List.

2.4.6.9 Candidate Site List

The Alliance concluded that it was imperative for the success of the FutureGen Project that candidate sites offer: (1) an acceptable location for siting a power plant; (2) at least one acceptable geologic storage formation; and (3) minimal risks of schedule delays or project failure. Based on this assessment, the Alliance determined that four of the eight qualified sites met these three requirements. The reasons for screening out the other four qualified sites are discussed below.

Of the eight sites that met all of the qualifying criteria, three scored substantially lower than the others, taking into account the results of both the power plant site and the injection site scoring criteria. Overall, these three sites achieved relatively low scores in the following areas and were excluded from further consideration:

- Proximity to sensitive areas;
- Distance to transmission lines and to transportation for material and fuel delivery;
- Penetrations of secondary seals for the target formation;
- Target formation properties, especially the extent of the plume area and the number of wells needed to meet the injection target;
- Ability to meet monitoring, mitigation, and verification (MM&V) requirements (see Section 2.5.2.2); and
- Additional regulatory requirements that would be imposed.

The Alliance also determined that one of the remaining five top-scoring sites posed substantial problems for construction given its relatively small size and the configuration of the site. Experts in power plant siting concluded that it would be difficult to construct a rail loop for coal delivery at the proposed site. This site was also located close to residential areas, which raised land use compatibility concerns. The net effect of the best value criteria was to weaken the standing of this site after the initial scoring and it was subsequently eliminated from the Candidate Site List (FG Alliance, 2006a).

At the end of the process, the Alliance removed the following qualified sites from consideration based on the application of the scoring and best value criteria under the Alliance's evaluation system:

- Illinois – Effingham
- Illinois – Marshall
- Kentucky – Henderson
- Ohio – Tuscarawas

The remaining four sites made the Candidate Site List. These four sites met all of the qualification criteria and scored highly in the opinion of the Evaluation Team. Furthermore, considering all of the information submitted, including information submitted for the best value criteria and the findings of the Site Visit Team, the Alliance found that these sites offer: (1) an acceptable location for siting a power plant; (2) at least one acceptable geologic storage formation; and (3) minimal risks of schedule delays or project failure. Therefore, the Alliance concluded that 4 of the original 12 sites proposed could be acceptable to host the proposed FutureGen Project and that the sites appear reasonable from a technical, environmental, and economic perspective. Best value criteria would be applied again to information provided by the site offerors during the final selection of a host site, should DOE approve the Proposed Action and more than one alternative site.

At the conclusion of the review of proposals, the Alliance provided DOE with a report (FG Alliance, 2006a) that describes the screening process, the results of the screening process, and identifies the sites that the Alliance concludes are candidates.

DOE reviewed the Alliance's report on the selection process (FG Alliance, 2006a) for fairness, technical accuracy, and compliance with the established approach. DOE concluded that the process met these requirements and determined that the Alliance's Candidate Site List, including the four sites described in Section 2.4, is the appropriate list of reasonable alternative sites for detailed analysis in this EIS.

The reasonable alternative sites are (in no order of preference):

- Mattoon, Illinois
- Tuscola, Illinois
- Jewett, Texas
- Odessa, Texas

2.4.7 TECHNOLOGY OPTIONS ELIMINATED FROM FURTHER CONSIDERATION

Pursuant to the President's FutureGen Initiative, DOE determined that all project alternatives must use coal as fuel, produce electricity, produce H_2, meet very low target emission rates, and capture and store emissions of greenhouse gases (GHGs). Therefore, DOE determined that reasonable alternatives would not include:

- Super-critical pulverized coal power plant technology – By using a single-step complete combustion process (unlike IGCC), these plants cannot produce significant quantities of H_2 without suffering an unreasonably large efficiency penalty when using the produced electricity to generate H_2 (e.g., by electrolysis).
- Integrated gasification fuel cell power plant technology – Project risk levels are too high given that fuel cells are not sufficiently developed at the size required for this project.
- Nuclear power plant technology – These plants do not use coal, which is a low-cost and abundant fuel resource. This option also does not allow an opportunity to demonstrate the capture and storage of GHG emissions.
- Renewable resource technologies (which do not use coal and do not allow an opportunity to demonstrate the capture and storage of GHG emissions including wind power, wave power, geothermal energy, solar energy, and biomass combustion). Other DOE programs and projects aim to further the development of renewable resource technologies as part of DOE's diverse portfolio of energy research, development, and demonstration efforts.
- Energy efficiency improvement technologies (e.g., through conservation and improvements in demand-side efficiencywhich do not generate H_2 or electricity from coal. However, increasing energy efficiency does complement the goals of the FutureGen Project to help reduce emissions of CO_2 and other GHGs from coal-fueled energy production.

Many of the technologies eliminated from consideration are addressed by other programs and projects in DOE's diverse portfolio of energy research, development, and demonstration efforts. These technologies, along with increasing energy efficiency, complement the goals of the FutureGen Project to help reduce emissions of CO_2 and other GHGs from coal-fueled energy production.

Geologic sequestration was identified as a reasonable alternative for meeting the requirement of reduced GHG emission. Other sequestration alternatives considered, but eliminated, include:

- Deep ocean sequestration – Deep ocean sequestration is the deliberate injection of captured CO_2 into the ocean at great depths where it could potentially be isolated from the atmosphere for centuries (IPCC, 2005). This technology currently exists; however, the knowledge base is inadequate to determine what biological, physical, or chemical impacts might occur from interactions with the marine ecosystem.

- Terrestrial sequestration – Terrestrial sequestration is the process of atmospheric CO_2 absorption by trees, plants, and crops through photosynthesis and storage as carbon compounds in biomass (tree trunks, branches, foliage, and roots) and soils. While terrestrial sequestration may be an attractive and useful sequestration option, the uncertain long-term accountability and permanence of CO_2 storage and the inability to directly store the CO_2 captured from power plants makes this option unlikely to be implemented in the electrical power industry (NETL, 2007).
- Mineral sequestration – Mineral sequestration is the process of reacting CO_2 with metal oxide-bearing materials (typically minerals like forsterite or serpentine) to form insoluble stable carbonates, with calcium and magnesium being the most commonly used metals (IPCC, 2005). The main challenge for mineral sequestration is developing a commercial process for reaction of the naturally occurring minerals with CO_2 to form carbonates. Even though the reaction is thermodynamically favored, it is extremely slow in nature, and therefore, its economic viability is uncertain (Herzog, 2002).

DOE also considered, but eliminated the alternative of attaching CO_2 capture devices and sequestration facilities to an existing or planned commercial power plant. Such an approach could meet the FutureGen Project's objectives without the cost of planning, designing, and building a new power plant. However, this alternative was eliminated for the following reasons:

- Existing or planned non-IGCC power plants – Almost all non-IGCC power plants are not sufficiently pressurized to reduce the efficiency penalty associated with capture and compression of CO_2. In addition, these plants cannot produce appreciable quantities of H_2 without suffering an unreasonably large efficiency penalty when using the produced electricity to generate H_2 (e.g., by electrolysis).
- Existing or planned IGCC power plants – Owners of these plants have not volunteered their existing or planned IGCC power plants for the FutureGen Project. Existing plants would not be able to accommodate equipment for pre-combustion capture of CO_2 from synthesis gas without extensive modification, and would not have the necessary features that create a research platform to meet the FutureGen Project's research, development, and demonstration objectives.

Owners of existing and planned power plants, including IGCC plants, would not accept the financial and operational risks associated with adding CO_2 capture devices and experimental geologic sequestration to their plants. Commercial ventures generally cannot accept the intensive testing and interruptions of power generation that would be associated with the research and development activities of the FutureGen Project. Commercial operators are bound by power purchase agreements that are unforgiving of delivery failures, and the power market does not offer much flexibility in negotiating the terms and conditions in these agreements. While the idea of "attaching" the FutureGen Project to an existing or planned IGCC power plant is technically feasible, it is unreasonable from a business perspective.

On April 21, 2003, DOE published a Request for Information in the *Federal Register* (68 FR 19521) openly inviting expressions of interest from organizations capable of implementing the FutureGen Project. Only one qualifying group (the Alliance) submitted an expression of interest. No existing or planned power plant operators offered to modify their plants to achieve the FutureGen Project goals.

To meet the FutureGen Project objectives, DOE requires advancements in the facility's design, experimentation in a near-laboratory setting (including experimentation in a test platform), and operational technology development (at a full-scale and at a reduced scale in available side streams and slip streams). These advancements would be more appropriate for a research platform, such as the FutureGen Project, rather than an existing commercial power plant.

2.4.8 PREFERRED ALTERNATIVE

DOE's preferred alternative is to provide financial assistance to the FutureGen Project, assuming that one or more sites would be found acceptable in the Record of Decision (ROD). DOE tentatively finds all four sites to be acceptable. If DOE ultimately selects the preferred alternative (to grant financial assistance to implement the FutureGen Project at any of the four sites), DOE would then determine for each site whether mitigation of specified potential impacts would be required. DOE is also free, however, to ultimately determine in the ROD that fewer than all four sites are acceptable, or to select no action.

2.5 THE FUTUREGEN PROJECT

This section describes specific FutureGen technologies and activities. The FutureGen Project is in the early stages of design and, although the major features of the project are known, many engineering and planning details are still in the developmental stage. The Alliance developed reference design information and bounding conditions for use in this EIS. Where appropriate, design uncertainties and bounding conditions used are indicated in this EIS. As the conceptual design work progresses, the Alliance would make decisions on the incorporation of specific technologies consistent with the overall project goals. Future activities that would be undertaken are described in Section 2.6.

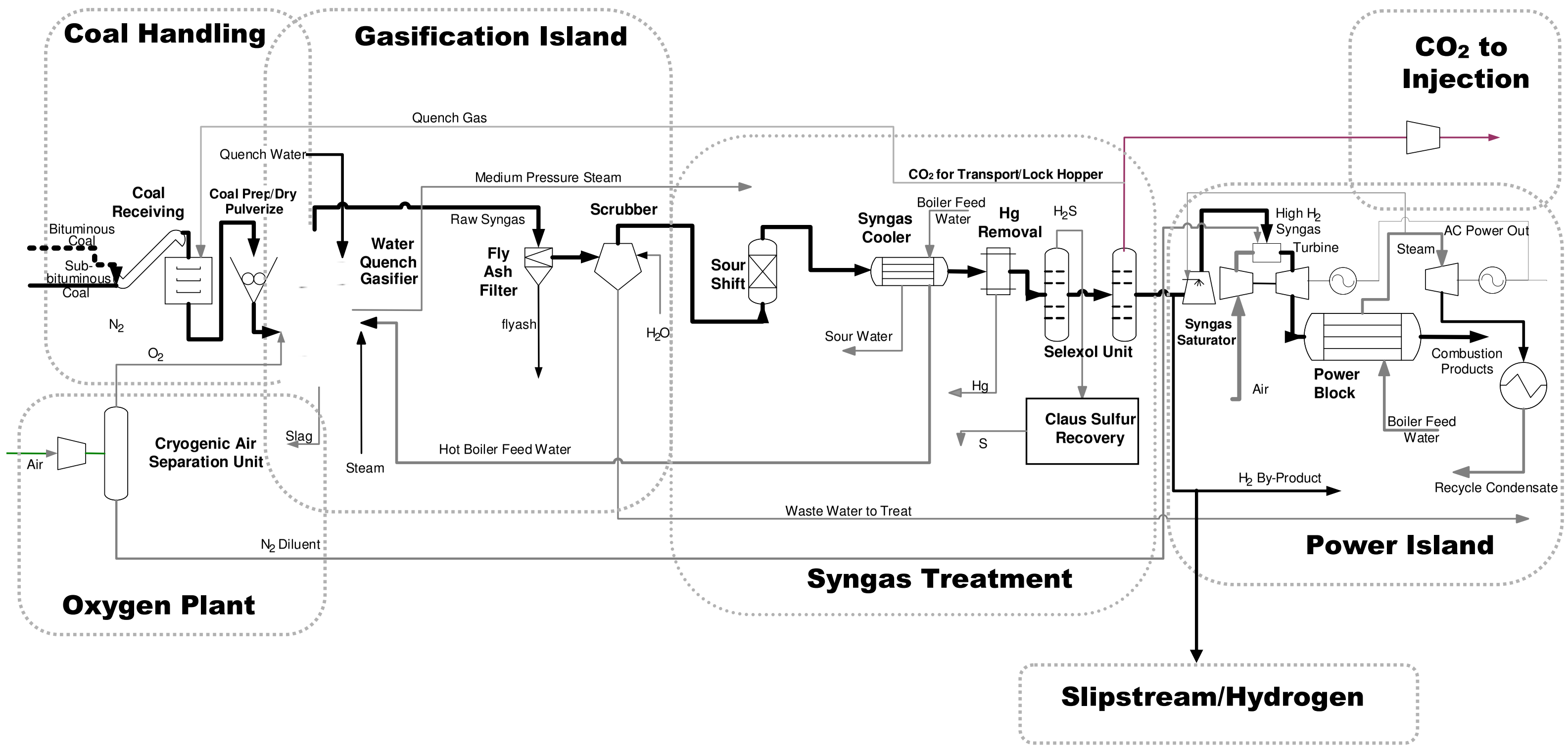
2.5.1 POWER PLANT AND RESEARCH FACILITY

The FutureGen Power Plant would be a 275-MW output IGCC system. The major components of this system are illustrated in Figure 2-17 and an example plant layout is provided in Figure 2-18.

The following sections provide general descriptions of each feature including coal handling equipment, gasifier, syngas cooling, syngas conditioning, combined cycle power system, flare, cooling towers, and the zero liquid discharge (ZLD) system. Because the facility is in the early stages of design, the specific types, makes, and models of equipment have not been determined.

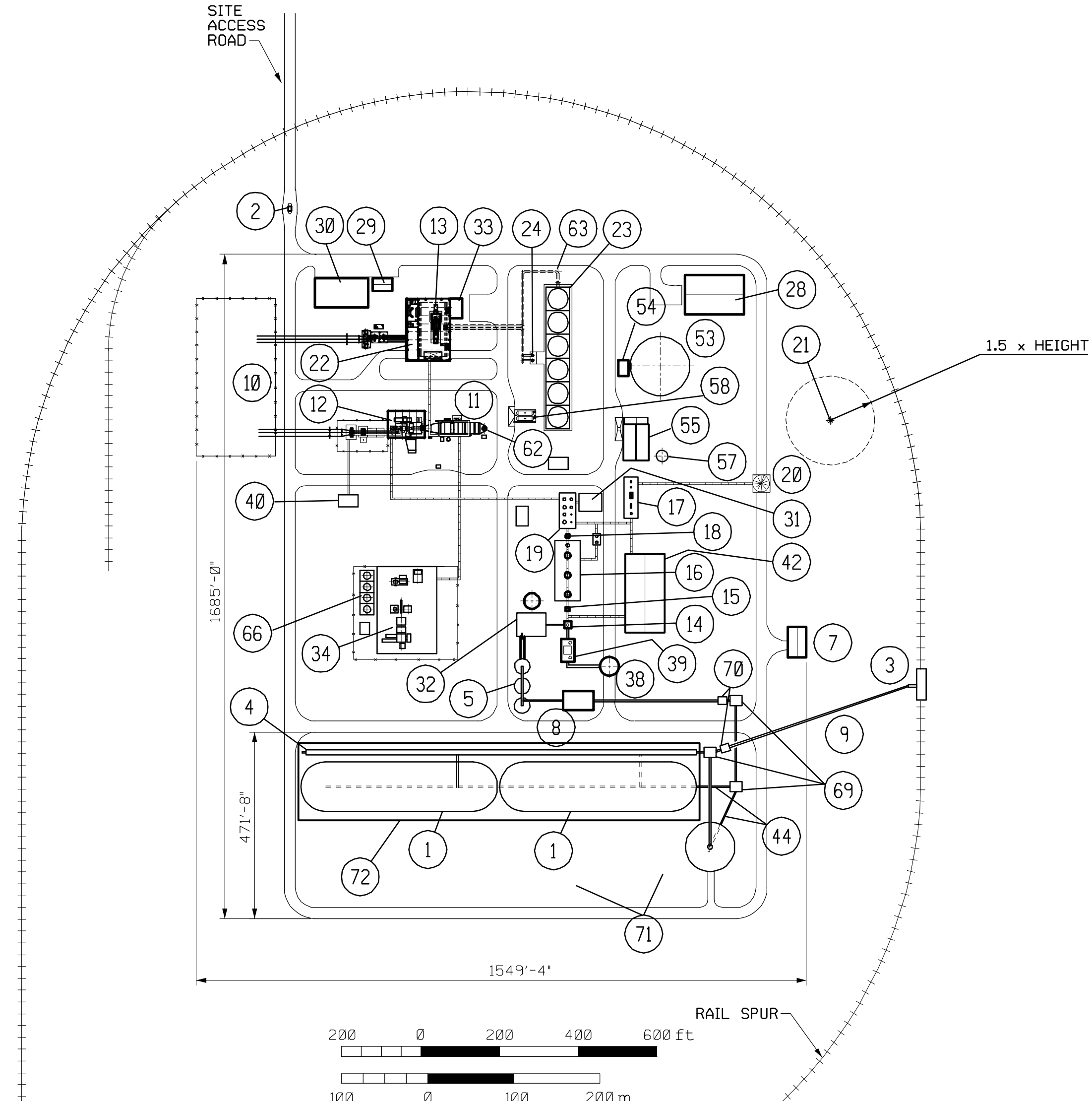
Planned research, development, and demonstration activities (see Figure 2-19) would use all elements of the facility, including the backbone power generation train, an optional side-stream power train (see discussion on Case 3B later in this section), a sub-scale test platform (or test bay), and the CO_2 sequestration facility located outside the power plant. In addition to research and development on power plant technologies, the FutureGen Project could serve as the premier platform for testing and deploying new technologies related to CO_2 storage, retention, and monitoring, and for developing a critical understanding of reservoir structure, chemistry, and performance.

The "backbone" refers to the equipment train necessary to fulfill the major objective of the FutureGen Project (i.e., commercial-scale, power generation with a minimum of 1.1 million tons [1 MMT] of CO_2 captured and stored per year). The facility's test platform and optional side-stream power train would enable full-scale module testing as well as sub-scale testing of new components and systems using syngas, H_2, or other chemicals produced by the facility. While design and construction of the facilities required to allow such testing to occur are part of the Proposed Action, the use of the test platform would be funded outside the scope of the FutureGen Cooperative Agreement.



AC = Alternating current
Source: Adapted from FG Alliance, 2007*b*

Figure 2-17. Block Diagram of and Example Design for the FutureGen Power Plant



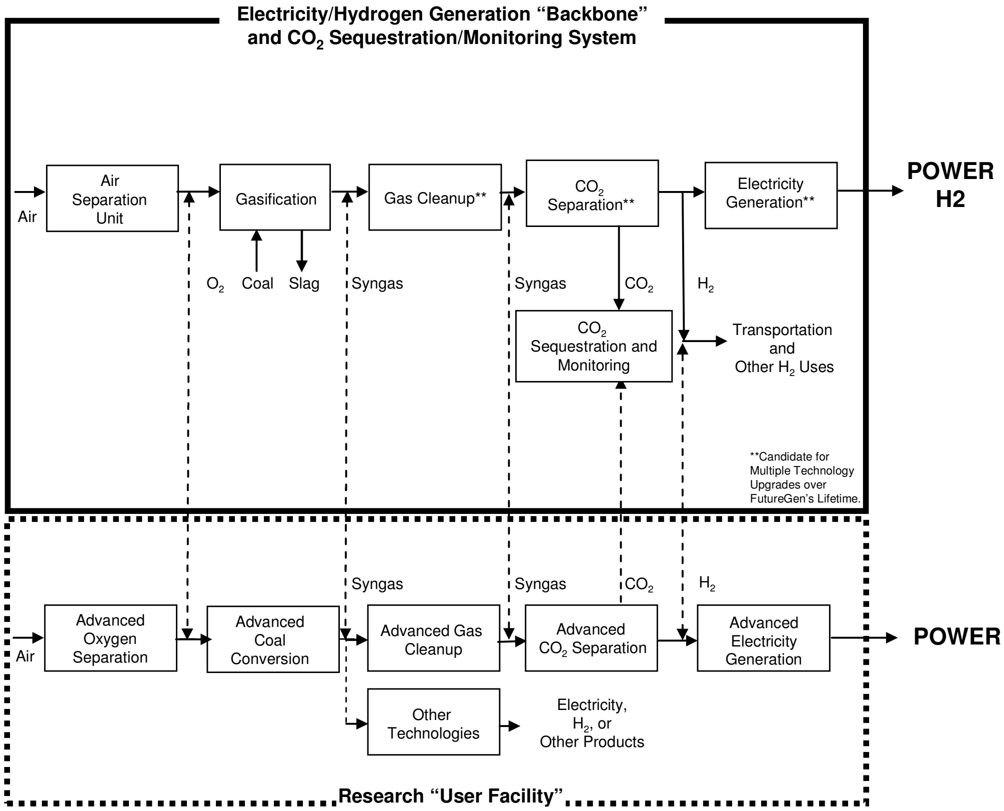
1. COAL STORAGE
2. GUARD HOUSE
3. COAL RECEIVING
4. COAL TRAVELING STACKER
5. COAL STORAGE BINS
6. UTILITY BRIDGE*
7. VEHICLE MAINTENANCE GARAGE
8. CRUSHER BUILDING
9. BELT CONVEYORS
10. SWITCHYARD
11. HEAT RECOVERY STEAM GENERATOR
12. COMBUSTION TURBINE
13. STEAM TURBINE GENERATOR
14. GASIFIER
15. GAS SCRUBBER
16. SHIFT REACTION SECTION
17. CLAUS PLANT
18. MERCURY REMOVAL
19. ACID GAS REMOVAL
20. SULFUR STORAGE
21. FLARE STACK
22. ELECTRICAL ROOM
23. COOLING TOWER
24. CIRCULATING WATER PUMPS
28. WAREHOUSE
29. ADMINISTRATION BUILDING
30. VISITORS CENTER
31. CO_2 COMPRESSION
32. SLURRY PREPARATION
33. WORKSHOP AND STORES
34. AIR SEPARATION UNIT
38. SLAG SILO
39. SLAG PROCESSING AREA AND WATER HANDLING
40. ASU ELECTRICAL BUILDING
41. COAL ELECTRICAL BUILDING*
42. RESEARCH AND DEVELOPMENT FACILITY
43. SOUR WATER STRIPPERS*
44. RECLAIM CONVEYORS
46. EMERGENCY DIESEL GENERATOR*
47. CONTINUOUS EMISSIONS MONITORING SYSTEM ENCLOSURE*
48. CONTROL ROOM*
49. AUXILIARY TRANSFORMERS*
50. STEAM TURBINE GENERATOR STEP UP TRANSFORMER*
51. GENERATOR CIRCUIT BREAKER*
52. COMBUSTION TURBINE GENERATOR STEP UP TRANSFORMER*
53. FIRE SERVICE WATER TANK
54. FIRE SERVICE WATER PUMP HOUSE
55. WATER TREATMENT FACILITY
56. CHEMICAL TRUCK UNLOADING*
57. DEMINERALIZED WATER TANK
58. AMMONIA STORAGE TANKS AND PUMPS
59. AMMONIA UNLOADING AREA*
60. SELECTIVE CATALYTIC REDUCTION SKID*
61. AIR INLET FILTER*
62. STACK
63. CIRCULATING WATER PIPING
64. SLURRY STORAGE TANK*
65. CHEMICAL TREATMENT SKID*
66. ASU COOLING TOWER
69. TRANSFER BUILDING
70. SAMPLE SYSTEM
71. EMERGENCY COAL PILE
72. COAL PILE ENCLOSURE

* = Not shown in figure

Note: Figure is an example of a typical power plant configuration; however, all components of the typical configuration would not be included in the proposed FutureGen facility. Consecutive numbers missing from the legend result from this difference.

Source: FG Alliance, 2007***b***

Figure 2-18. Example FutureGen Project Configuration



Source: Adapted from FG Alliance, 2007***b***.

Figure 2-19. FutureGen Power Plant Overview

Prototype testing of advanced technologies would be considered in the following areas:

- Fuel Processing Power Plant – Electric power production, H_2 production and carbon capture
  - Coal feed – Tests of high pressure, continuous dry coal feed systems have the potential to reduce equipment cost and improve plant efficiency. Current dry feed systems use lock hoppers, which result in multiple vessels and cyclic operation to achieve continuous feed.
  - Oxygen supply (air separation) – Use of ceramic membrane technology for separating oxygen (O_2) from air offers the opportunity to reduce capital cost and reduce auxiliary power consumption relative to conventional cryogenic air separation technology.
  - Syngas preconditioning – The syngas composition is shifted to maximize the CO_2 concentration for removal. Advanced technologies are proposed that would allow for shifting the syngas composition and separating the CO_2 in the same unit operation, thus simplifying the process.
  - Syngas cleaning – Particulate, sulfur, halides, alkali, ammonia (NH_3), mercury (Hg), and other trace metal compounds are removed in the syngas cleaning sub-system. Cleaning can be achieved today with processes operating at low temperature. Advanced technologies are being developed to allow this cleaning to occur at an elevated temperature to retain the water content in the syngas. This results in increased plant efficiency. Lower capital cost also could be possible with these advanced technologies.
  - CO_2 removal/separation – There are many advanced concepts being developed that have the potential to reduce the cost of removing CO_2 from the shifted syngas stream. The CO_2 can be removed by separating CO_2 or H_2. Advanced technologies include membranes (e.g., ceramic, polymer, metal), solid sorbent materials, and solvents. Technology that operates at elevated

temperatures can be combined with the advanced syngas cleaning technology to realize benefits in overall plant efficiency.

  - Power systems – The electric power is currently generated through the use of gas turbines and steam turbines. Advanced gas turbine technology would allow for increased plant efficiency using H_2 rich fuel and would also be designed to achieve reduced NO_X emissions. Fuel cells (e.g., solid oxide fuel cells) are being developed that have the potential to increase plant efficiency by incorporating this technology with the turbine technology.
  - Water management – Advances in this area include advanced cooling technology, water recovery, and non-traditional water use for cooling. Examples of benefits include recovery and reuse of heat to improve plant efficiency; use of lower quality water and allowing the wastewater to be concentrated for zero water discharge; recovery of water lost in wet cooling tower plumes for reuse in the plant; and water management concepts to minimize the use of water.
- Carbon Sequestration
  - Power plant/sequestration integration – The proposed FutureGen Project would allow for operating an integrated plant with power production, H_2 production, carbon capture, and CO_2 sequestration. Advances in process operation and control would be tested and would provide opportunities for advanced sub-system technology.
  - Monitoring and mitigation – The monitoring system is important to verify the injected CO_2 has been sequestered, to track the fate of CO_2 over time, to provide data to confirm predictive models, and to detect leakage of CO_2. Technology is available to perform these tasks. Advanced technologies will provide opportunities to advance the automation of monitoring and to reduce the cost
  - Reservoir modeling and science – The FutureGen Project would collect extensive data on the fate of CO_2 and the environment containing the CO_2. These data would enable advances in reservoir modeling and our understanding of the science associated with sequestration phenomena.
  - Sequestration of H_2S gas with CO_2 co-sequestration – The ability to co-sequester CO_2 and H_2S provides an opportunity to achieve greater improvements in plant efficiency and reduced capital cost. This facility allows for understanding the potential for this option through analysis and modeling that would determine design and operation requirements to meet project requirements and testing based on these analyses.

The FutureGen Project would also function as a platform for testing and deploying new concepts related to CO_2 storage, monitoring, and leak mitigation. The FutureGen Project would provide an opportunity to develop a critical understanding of reservoir structure, chemistry and performance. A preliminary monitoring scheme and descriptions of these monitoring techniques are discussed in Section 2.5.2.2. The research strategy would be designed to advance the science and engineering of geologic sequestration in the following areas:

- Processes of fluid flow and fluid momentum, conservation of mass, and energy fluxes in complex, heterogeneous porous rock and fractured rock, including large-scale connectivity and flow characteristics;
- Coupled thermal-hydraulic-mechanical-chemical processes and feedbacks;
- Transmission of stresses and impacts of stresses on CO_2 transport and containment;
- Projection of system response over large areas through remote sensing and monitoring, data integration, and reservoir modeling;
- Automated controls linking the power plant to the CO_2 storage reservoir to ensure safe and economical operations;
- Strategies to improve injection or CO_2 trapping; and
- Sequestration of CO_2 with other gases, such as H_2S with CO_2.

Coal Handling Equipment

Coal handling equipment unloads, conveys, prepares, and stores coal delivered to a power plant. The equipment used for an IGCC plant is largely the same as that used at a conventional coal-fueled power plant. The coal is crushed or pulverized before feeding into the gasification system. Some systems dry feed the coal through lock hoppers, while others feed the fuel in a coal-water slurry (Rosenberg et al., 2005). The coal feed method for the FutureGen Project would depend upon the type of gasifier selected by the Alliance (see Table 2-5).

Coal would be transported to the facility by rail (see Section 2.5.5.1). The unloading would be done by a "rapid rail" type unloading system utilizing bottom dump railcars that travel continuously at a slow speed and unload the coal into two receiving hoppers below the rail. Coal would then be withdrawn from each hopper by a single belt feeder. The coal would then be discharged from the belt feeder onto a belt conveyor that includes a belt scale and an "as-received" sample system. The coal would then be conveyed to a transfer tower where it would be directed either to a main storage pile or onto an emergency storage pile (FG Alliance, 2007***b***). A detailed discussion of unloading and loading activities are discussed in Volume II for each site in Sections 4.14, 5.14, 6.14, and 7.14. Coal would be stored on site in two piles, each providing a 15-day supply, or as one long coal pile of similar size. The coal piles would be either covered or uncovered, depending on operational, environmental, and economic considerations. If covered, the conceptual design allows for the possibility of a Quonset hut-type building for on-site coal storage. Approximate dimensions would be 600 feet (182.9 meters) long by 50 feet (15.2 meters) wide by 75 feet (22.9 meters) high.

Gasifier

The gasification process would combine coal, O_2, and steam to produce a H_2-rich synthesis gas or "syngas." After exiting the gasifier, the composition of the syngas, predominantly H_2 and CO, would be "shifted" to produce additional H_2. The product stream would consist mostly of H_2, steam, and CO_2. After separation of these three gas components, the H_2 would be used to generate electricity in a gas turbine or fuel cell. A slip stream of H_2 would also be available for use in on-site research and development activities. Steam from the process would be condensed, treated, and recycled into the gasifier or added to the plant's process water circuit. The separated (i.e., captured) CO_2 would be permanently sequestered.

Gasifiers of the types envisioned for the FutureGen Project operate at high temperatures (2,000 to 3,000°F (1,093°C to 1,649°C) and elevated pressures (400 to 1,000 psi [2,758 to 6,895 kPa]) in the presence of O_2 gas and steam. While performance estimates developed under the conceptual design incorporate technologies that are considered commercial in nature, the actual selection of technologies would occur as a result of an open solicitation. Vendors would be encouraged to propose the most advanced design that fits the requirements and mission of the FutureGen Project.

Table 2-5. Power Plant Technology Cases under Evaluation for the FutureGen Project

Process or Component	Case 1	Case 2	Case 3	
			Unit A[1]	Unit B
Combustion Turbine	Frame 7FB	Frame 7FB	Frame 7FB	SGT6-3000
Gasifier Technology	Entrained Flow with Water Quench	Entrained Flow with Water Quench	Entrained Flow with Water Quench	Transport
Oxidant	95 mole percent Oxygen	95 mole percent Oxygen	95 mole percent Oxygen	TBD mole percent Oxygen

Table 2-5. Power Plant Technology Cases under Evaluation for the FutureGen Project

Process or Component	Case 1	Case 2	Case 3	
			Unit A[1]	Unit B
ASU	Cryogenic	Cryogenic	Cryogenic	Ion Transport Membrane
Coal	Pittsburgh Illinois PRB	Pittsburgh Illinois PRB	Pittsburgh Illinois PRB	Pittsburgh Illinois PRB
Coal Feed	Slurry	Dry	Slurry	Dry
H_2S Separation	Physical Solvent 1st Stage	Physical Solvent 1st Stage	Physical Solvent 1st Stage	Chemical Solvent
Sulfur Removal (minimum)	99 percent	99 percent	99 percent	99 percent
Sulfur Recovery	Claus Plant/ Elemental Sulfur	Claus Plant/ Elemental Sulfur	Claus Plant/ Elemental Sulfur	Claus Plant/ Elemental Sulfur
CO_2 Separation	Physical Solvent 2nd Stage	Physical Solvent 2nd Stage	Physical Solvent 2nd Stage	Physical Solvent 2nd Stage
CO_2 Capture (minimum)	1 million tpy (0.9 million mtpy), 90 percent	1 million tpy (0.9 million mtpy), 90 percent	1 million tpy (0.9 million mtpy), 90 percent	1 million tpy (0.9 million mtpy), 90 percent
CO_2 Sequestration	Plant Gate, 2200 psig(15,168 kPa)	Plant Gate, 2200 psig (15,168 kPa)	Plant Gate, 2200 psig (15,168 kPa)	Plant Gate, 2200 psig (15,168 kPa)
H_2 Production	835 lb/h (378.7 kg/h) at 100 percent purity	835 lb/h (378.7 kg/h) at 100 percent purity	835 lb/h (378.7 kg/h) at 100 percent purity	None

[1] Case 3A differs from Case 1 in that its gasifier and coal handling systems were sized for maximum coal feed rates. The larger feed rates would provide enough syngas production to fully load the combustion turbine regardless of the type of coal used.
ASU = air separation unit; TBD = To be determined; tpy = tons per year; mtpy = metric tons per year; psig = pounds per square inch gauge measurement;
kPa = kilopascal; lb/h = pounds per hour; kg/h = kilograms per hour.
Source: FG Alliance, 2007***b***.

Due to advantages in gas cleanup economics as well as combustion turbine requirements, it is expected that the FutureGen Project would be a high-pressure O_2-blown facility. O_2-blown gasification requires supplying a stream of compressed O_2 gas (rather than air) to the gasification reactor. Commercially available O_2 plants, commonly called an air separation unit, operate at very low temperatures (cryogenic). Cryogenic O_2 production is an established commercial process that is used extensively worldwide (Rosenberg et al., 2005). Recent advances in membrane air separation have shown promise, and the Ion Transfer Membrane O_2 system is one advanced technology that has shown merit for inclusion in some capacity at the FutureGen Project.

Slag and **ash** are residues produced by the combustion of coal. Slag is heat-fused material that accumulates on the sides and bottom of a gasifier and is removed periodically. Ash includes solids produced from the bottom of the gasifier (bottom ash) and solids entrained with the syngas (fly ash). The slag or ash would be recycled for beneficial use or disposed of according to environmental regulations.

The FutureGen Project would generate up to 96,865 tons (87,875 metric tons) of slag and ash per year, of which 47,565 tons (43,151 metric tons) would be ash. Slag and ash are residues produced by the combustion of coal. Whether slag is formed depends on the type of gasifier. Gasifiers that operate at temperatures exceeding coal fusion temperature are termed "slagging." The FutureGen Project is considering both slagging and non-slagging gasifier options. If a local market exists, the slag or ash would be transported off site to a recycling facility or manufacturer that could recycle it into a beneficial product. Alternatively, the slag or ash could be disposed of off site at a commercial landfill or at an on-site landfill, if one is constructed. The quantity of slag or ash would increase by 49 percent if Case 3B were implemented although this option is considered unlikely.

Syngas Cooling

Coal gasification systems operate at high temperatures and produce raw, hot syngas. Typically, the syngas is cooled from around 2,000°F (1,093°C) to below 1,000°F (538°C), and the heat is recovered. Cooling is accomplished using a waste heat boiler or a direct quench process that injects either water or cool, recycled syngas into the raw syngas. When a waste heat boiler is used, steam produced in the boiler is typically routed to the heat recovery steam generator (HRSG) to augment steam turbine power generation (Rosenberg et al., 2005).

Syngas Conditioning

The syngas conditioning process involves removing particulate matter, converting CO in syngas to CO_2 (shifting), and capturing sulfur, and nitrogen, and other chemical compounds from the syngas before it is input to the combustion turbine. Particulate removal is accomplished using either barrier filters or by water scrubbers located downstream of the cooling devices. The particulate matter, including char and fly ash, is typically recycled back to the gasifier. When filters are used, they are cleaned by periodically back-pulsing them with fuel gas to remove trapped material.

CO is shifted by adding steam and flowing the mixture through a selective catalytic reduction process, converting the CO to CO_2 and producing H_2. Any carbonyl sulfide (COS) in the syngas would be converted to H_2S and captured downstream. Once filtered and cooled, the syngas is treated in two-stages of cleanup (called acid gas removal [AGR]); the first stage separates H_2S and mercury (Hg) and the second stage separates the CO_2 and produces a concentrated stream of H_2. The H_2S would be diverted to the sulfur recovery unit (SRU). Hg would likely be removed using activated carbon beds.

Current commercial AGR processes are chemical solvent-based processes or physical solvent-based processes. Chemical solvent-based processes use aqueous solutions of amines such as methyl diethanolamine (MDEA) and physical solvent-based processes (such as Selexol™) use dimethyl ethers of polyethylene glycol, or Rectisol™, which uses refrigerated methanol. Polyethylene glycol and methanol are chemically inert and can be regenerated (recycled) through depressurization in a “flash tank” (a unit that separates liquid and gas phases) although additional processing is necessary to remove the H_2S absorbed by the solvent. Polyethylene glycol and methanol are chemically inert. Under all technology cases (see Table 2-5) except 3B, a physical solvent would be used. Case 3B would use an amine solution.

Sulfur recovery processes recover sulfur in the form of either sulfuric acid or elemental sulfur. The most common removal system for sulfur recovery is the Claus process, which produces marketable elemental sulfur from the H_2S in the syngas (Rosenberg et al., 2005). The preliminary concept for the FutureGen Project assumes use of a Claus process.

> The **Claus process** recovers elemental sulfur from gaseous H_2S. It is a multi-step thermal and catalytic process where the final step involves oxidation of H_2S. The main reaction equation is:
> $2H_2S + O_2 \rightarrow 2S + 2H_2O$

Combined Cycle Power System

After cleanup, the concentrated H_2 stream flows to the combined cycle power system. In a combined cycle system, the first cycle involves the combustion of the primary fuel, H_2, in the case of the FutureGen

Project, in a combustion turbine. The combustion turbine powers an electric generator. It also may compress air for the ASU or gasifier. Hot exhaust gases are captured and directed to an HRSG, which produces steam. For the second cycle, the steam drives a steam turbine to produce additional electricity. The two electricity generation systems, one with a combustion turbine and the other with a steam turbine, constitute the combined cycle power system and generate more electricity than the older conventional systems that only use a steam turbine.

Flare

The FutureGen Project would be equipped with a flare to combust syngas during normal startups resulting in unplanned restart emissions and during plant upsets (also called unplanned outages). The flare would have a single stack and a single flame. The stack height would be up to 250 feet (76.2 meters) high, and the flare would be designed for a minimum 99 percent destruction efficiency of CO and H_2S.

> **Plant upset** is a serious malfunction of any part of the IGCC process train and usually results in a sudden shutdown of the combined-cycle unit's gas turbine and other plant components.

Cooling Towers

The FutureGen Project would likely include a hybrid cooling system to reduce water usage, consisting of a mechanical draft cooling tower combined with a convective heat removal system. Most of the water appropriated for the power plant would be consumed by evaporative cooling. The amount of water required would be influenced by many factors including: ambient weather conditions; the cycles of concentration in the cooling towers; and the quality of the make-up water source. In general, if the source water is relatively low in total dissolved solids, the cycles of concentration in the cooling towers can be increased, resulting in less water consumption.

Zero Liquid Discharge System

> **ZLD system** is a process involving the separation of solids and dissolved constituents from the plant wastewater and allowing the treated water to be recycled or reused in the industrial process, resulting in no discharge of process wastewater to the environment.

The FutureGen Project would use a ZLD system to eliminate industrial wastewater discharges. Cooling tower blowdown (i.e., water removed from the cooling system) ***and other process water streams*** would be routed to the ZLD system to remove solids and dissolved constituents before reuse in the cooling tower. The ZLD process would first remove suspended solids in a clarifier, concentrate the dissolved solids using a reverse osmosis system, and then remove water from the dissolved solids through heating and vaporization. The ZLD process results in a solid filter cake material, which would be collected and transported off site for proper disposal. Based on the conceptual design estimates, up to 1,545 tons (1,402 metric tons) of clarifier sludge and 5,558 tons (5,043 metric tons) of solids (filter cake) would be generated by the ZLD system per year of operation.

2.5.1.1 Technology Options and Bounding Conditions

To support this EIS, the Alliance in consultation with DOE developed an initial conceptual design, which includes reference information for use in the impact analyses of this EIS. To develop bounding conditions, a range of outputs was developed based on the three technology cases summarized in Table 2-5. To provide a conservative assessment of impacts, the assumptions and quantities (particularly air emissions, other waste streams, and land impacts) relate to the upper bound of the range of possible impacts. For example, the upper bound for air emissions was derived by assuming facility operations would result in the highest emission rate of individual pollutant species (e.g., NO_x) selected from among all three cases. Therefore, while used to develop the performance boundary, the aggregate upper bound is worse than any single technology case under consideration.

An important part of the FutureGen Project is to incorporate the latest technologies ready for full-scale or sub-scale testing or commercial deployment. To identify technology options, the Alliance started with a list of major components and subsystems of the power plant facility and created a matrix of potential configurations of equipment. After presentations by various technology vendors and with assistance from numerous power plant experts, the matrix of potential configurations was narrowed to three to support the conceptual design. While the final technology selections have not yet been made, the IGCC processes would be generically similar, regardless of specific technologies.

The Alliance is evaluating three potential technology cases. These cases share many components and processes in common, with the primary difference being the type of gasifier technology used. Table 2-5 summarizes the technology cases and their components. Cases 1, 2, and 3A are stand-alone alternatives that are capable of meeting the design requirements of the project. Case 3B is a smaller, side-stream power train that would enable more research and development activities than the main train of the power plant (Cases 1, 2, and 3A). Case 3B, if implemented, would be paired with Cases 1 and 2, and 3A. Case 3A is similar to Case 1, except the gasifier output is greater.

One goal of the FutureGen Project is to demonstrate gasification technology over a range of different coal types. Therefore, the facility would be designed to use bituminous, sub-bituminous, and ***possibly*** lignite coals. For developing the performance boundary, the Alliance assumed technology cases and operation of the plant using three coal types: PRB sub-bituminous, Illinois Basin bituminous, and Northern Appalachia Pittsburgh bituminous.

The Alliance estimated the operating parameters for a bounding combination of the technologies and coal types. Emissions of air pollutants, quantities of coal and process chemicals, and waste generation were calculated ***as*** the maximum possible under Cases 1, 2, and 3A for the three coal types, plus the maximum possible under Case 3B for the three coal types. This resulted in conservative estimates of possible air emissions and impacts related to use of process materials, waste management, and the associated transportation.

The FutureGen plant may not be designed optimally for any fuel type to either maximize efficiency in energy conversion or minimize pollutant emissions. Furthermore, because the plant would be designed to accommodate a variety of research and development (R&D) applications that may be proposed in the future, plant components would be integrated loosely such that the power plant as a whole may not perform optimally from an energy conversion perspective.

The FutureGen Project would have a sophisticated control system to safely manage normal operations as well as planned and unplanned restarts. Unplanned events include situations where a specific component or system has a performance problem and actions are required to restore normal operations or shut down the plant. Unplanned events may involve such actions as venting syngas to a flare for a short period (hours). Air emissions during startups and unplanned events (upset conditions) tend to be very high in pollutants emitted relative to normal operations, but occur for short durations (minutes to hours). For purposes of estimating the upper bound of air emissions, the air emissions profile used in this EIS includes an estimated number of unplanned restarts. Therefore, the air emissions profile would be greater than anticipated from steady-state operation of the project. Details on the air emissions estimates and assumptions are provided in Section 2.5.6.1. Even with including all unplanned restarts, the FutureGen Project is still expected to have low air emission levels when compared to traditional coal combustion power plants. As is the case with any new technology, the anticipated number of unplanned restarts usually declines with experience.

The FutureGen Project would also conduct research on additional technologies, which were described in Section 2.5.1. After the 4-year initial testing and research phase, it is likely that the power plant could still be used for additional research activities and would gradually over time be operated as a commercial power plant. Additionally, the Alliance could undertake various activities that would help offset the cost of operation. These activities include selling some or all of the CO_2 for enhanced oil recovery (EOR) or enhanced coalbed methane recovery, removing the Claus plant and co-sequestering H_2S with the CO_2, and possibly selling a portion of the H_2. These other operating scenarios are discussed in Section 3.3.

2.5.2 CARBON SEQUESTRATION

2.5.2.1 Overview of CO_2 Capture and Geologic Sequestration

A key component of the FutureGen Project is the geologic sequestration of CO_2 to help achieve near-zero emissions. Geologic sequestration is the storage of CO_2 in a suitable subsurface formation with the capability to contain it permanently. The injection of gases underground is not a new concept and has been performed successfully for decades, including natural gas storage projects around the world and acid gas injection at EOR projects.

> **Geologic Sequestration** is the placement of CO_2 or other GHGs into subsurface porous and permeable rocks in such a way that they remain permanently stored.
>
> **Deep Saline Formation** is an underground rock formation, generally more than 0.45 mile (731 meters) beneath the ground surface, composed of permeable materials and containing highly saline water.

Geologic storage of anthropogenic (man-made) CO_2 as a GHG mitigation option was first proposed in the 1970s, but little research was done until the early 1990s. In a little over a decade, geologic storage of CO_2 has grown from a concept of limited interest to one that is quite widely regarded as a potentially important mitigation option. Technologies that have been developed for and applied by the oil and gas industry can be used for the injection of CO_2 in deep geologic formations. Well-drilling technology, injection technology, computer simulation of reservoir dynamics, and monitoring methods can potentially be adapted from existing applications to meet the needs of geologic storage (IPCC, 2005).

Types of geologic formations capable of storing CO_2 include oil and gas bearing formations, saline formations, basalts, deep coal seams, and oil- or gas-rich shales. Not all geologic formations are suitable for CO_2 storage; some are too shallow and others have low permeability (the ability of rock to transmit fluids through pore spaces) or poor confining characteristics. Formations suitable for CO_2 storage have specific characteristics such as thick accumulations of sediments or rock layers, permeable layers saturated with saline water (saline formations), extensive covers of low permeability sediments or rocks acting as seals, (caprock), structural simplicity, and lack of transmissive faults (IPCC, 2005). ***DOE recommends that interested readers on this topic also see the Carbon Sequestration Atlas of the United States and Canada at http://www.netl.doe.gov/publications/carbon_seq/refshelf/atlas/index.html.***

Under the FutureGen Project, CO_2 from the power plant would be captured, transported by pipeline (if necessary), and injected into a deep saline formation (see Figure 2-20). The deep saline formation would be overlain by several other formations, including one or more low permeability caprock layers. Deep saline formations are the focus of the FutureGen Project because they are believed to have the largest capacity for CO_2 storage and are much more widespread geographically than other geologic sequestration options.

Improving the fundamental understanding of the transportation and geologic sequestration of large quantities of CO_2 is critical to advancing the commercial feasibility of this technology. This understanding is also important to public acceptance of this technology. The FutureGen Project would conduct subsurface research related to geologic storage of CO_2, and would function as a platform for testing and deploying new technologies related to CO_2 storage, monitoring, and, perhaps, leak mitigation. The project would help to develop a critical understanding for planners, engineers, and scientists to understand CO_2 sequestration in the context of formation structure, chemistry, and performance.

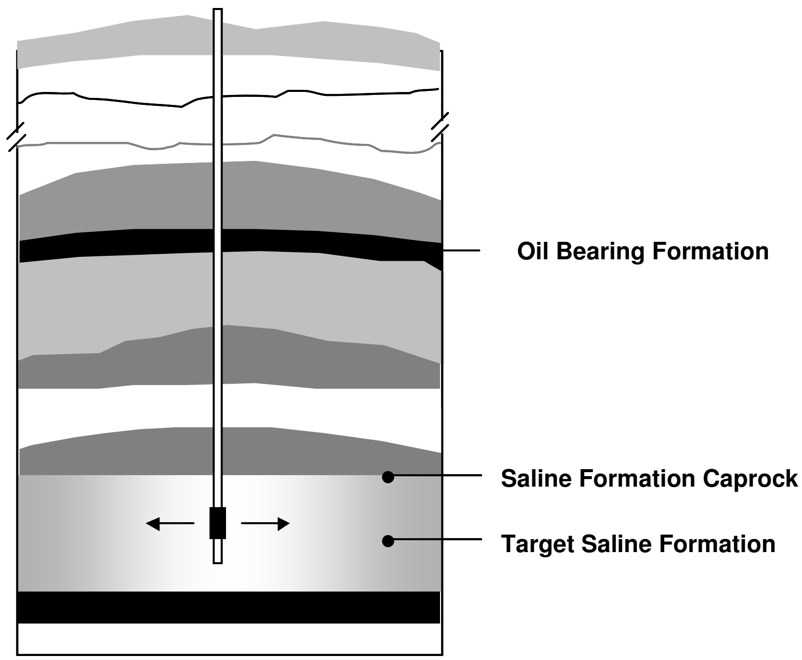


Figure 2-20. Geologic Sequestration in a Deep Saline Aquifer

Depending on the choice of monitoring technologies versus the length and costs for the pipelines, monitoring could be the most costly single component of the CO_2 storage effort because of the infrastructure required (e.g., deep monitoring wells) as a research and development project. The FutureGen Project would represent a first-of-a-kind environment in which to evaluate combinations of existing and new monitoring techniques and to determine the efficacy and cost of providing quantitative data on the location of the CO_2 plume, seal integrity, and early warning of CO_2 seepage. It is envisioned that the FutureGen Project would identify and validate less expensive and less invasive geologic sequestration technologies that could be used in future commercial applications (FG Alliance, 2007***b***).

CO_2 Capture

CO_2 capture from an IGCC power plant is generally less costly than capture from a conventional coal-fueled power plant because the CO_2 is relatively concentrated (50 volume percent) and at high pressure. The FutureGen Project would capture and remove CO_2 during the second stage of syngas cleanup using a physical solvent, before the syngas is mixed with air and burned in a combustion turbine.

CO_2 Compression and Transport

A CO_2 pipeline would transport the gas to one or more injection wells at the sequestration site. For three of the four alternative sites, injection wells would be miles away from the power plant site, requiring the construction of varying lengths of CO_2 pipeline. Depending upon the site selected, the Alliance would contract with a pipeline company or operator to use an existing CO_2 pipeline or to construct a new pipeline.

To deliver the captured CO_2 to the injection site, the gas would be compressed into a supercritical state (i.e., exhibiting properties of both a liquid and a gas) to make it more efficient to transport. CO_2 compression uses the same equipment as natural gas compression, with some modifications to suit the properties of CO_2. Avoiding corrosion and hydrate formation are the main pipeline operational issues with CO_2. Multi-stage centrifugal compressors are preferred for large volume, high-pressure applications because of their ability to handle large flow rates (several hundred thousands cubic feet per minute).

The water content in the CO_2 stream must be strictly limited to prevent corrosion. A glycol dehydrator can be used for this purpose. To avoid potential heat exchanger problems, stainless steel can be used throughout the compressor piping if H_2S is present in the CO_2 stream. Special sealing materials and gaskets are used to avoid hardening of some petroleum-based and synthetic lubricants in compressors and pipelines. Other impurities in the captured CO_2 streams ***(e.g., argon, H_2O, nitrogen, and O_2)*** may also affect the compressor and pipeline operations. Their impact is currently being researched (Wong, 2005). Once compressed, the CO_2 would be conveyed by pipeline to the sequestration site.

Approximately 1,500 miles (2,500 kilometers) of CO_2 pipelines exist in the United States. CO_2 pipelines are regulated as hazardous liquids pipelines. The U.S. Department of Transportation's CO_2 Pipeline and Hazardous Materials Safety Administration has responsibility for safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the Nation's pipelines. Ordinarily, federal approval is not required for development of a new hazardous liquids pipeline unless it would cross federal lands. Generally, state and local laws regulate construction of new hazardous liquids pipelines. However, under federal and state regulations, pipeline operators are responsible for ensuring the safe operation of their pipelines. Operators must use qualified materials and sound construction practices; thoroughly inspect, test, maintain, and repair their pipelines; ensure their workers are trained and qualified; implement BMPs to prevent damage to pipelines; and develop adequate risk management and emergency response plans. A Computational Pipeline Monitoring System is required by federal regulation (49 CFR Section 195.444) for leak detection in CO_2 pipelines. This type of leak detection system automatically alerts the operator when a leak occurs so that appropriate actions can be taken to minimize the release.

Most pipelines for hazardous liquids are located or buried within ROWs. A ROW consists of consecutive property easements acquired by, or granted to, the pipeline company. The ROW provides sufficient space to perform pipeline maintenance and inspections, as well as a clear zone where encroachments can be monitored and prevented. If an existing utility ROW is not available or suitable for the proposed CO_2 pipeline for the FutureGen Project, either the Site Proponents or the Alliance would obtain a new ROW.

The diameter of the pipeline would depend on many factors, particularly the length of the pipeline and transport pressure. For the FutureGen Project, the pipeline would be buried at least 3 feet (0.9 meter) below the surface except where it is necessary to come to the surface for valves and metering. Although valve spacing has not been determined at this time, a typical distance between metering stations is 5 miles (8 kilometers). These features may be aboveground or could be located below ground in concrete vaults. The pipeline would require protection from above ground loading at road crossings, either by increased wall thickness or by casing the pipe. In cold climates, transporting warm CO_2 could increase the ground temperature, which may affect ground frost and freeze in the winter. To avoid problems with icing at road crossings, the pipeline depth or pipe insulation thickness may be increased or the pipe can be armored.

CO_2 Injection and Storage

An objective of the FutureGen Project is to inject between 1.1 and 2.8 million tons (1 and 2.5 MMT) per year of CO_2 into a deep saline reservoir, providing permanent storage of the CO_2 underground. Most likely, all captured CO_2 would be stored in deep saline reservoirs; however, the goal is to sequester at least 1.1 million tons (1 MMT) of CO_2 per year in deep saline reservoirs. It is possible that CO_2 captured in excess of 1.1 million tons (1 MMT) per year would be sold for use in EOR or coalbed methane recovery. If any excess CO_2 is sold, DOE anticipates that the Alliance would restrict the uses of the CO_2 as a condition of the sales agreement so that the sequestration is permanent.

Assuming a 1.1 million ton (1 MMT) per year CO_2 injection rate and a 50-year power plant life span, the target formation could receive up to 55 million tons (50 MMT) of CO_2. The CO_2 gas would be injected at a pressure of approximately 2,200 psig (15,168 kPa). The number of injection wells required to meet the injection goal would vary, depending on the characteristics of the target formation. In addition, the Alliance may install one or more backup injection wells to accommodate periods of time for routine maintenance and inspection of the primary injection well(s). Where necessary, one or more extraction wells would be installed to remove formation water and thereby decrease the risk of over-pressurization caused by the injection of CO_2.

The alternative sites identified by the Alliance met stringent screening criteria with regard to their proposed injection sites. The Alliance, working in coordination with nationally recognized scientists and engineers, developed screening criteria that ensure that proposed formations provided not only adequate storage capacity but also exhibited features that would secure lasting, safe storage of CO_2. Some of these criteria are:

- The proposed target formation must have a primary seal (caprock) capable of long-term containment of the injected CO_2. Although “long-term” was not defined, the Alliance believed the criteria would provide secure and lasting storage of CO_2. Figure 2-20 shows an illustration of geologic sequestration depicting layers of caprock.
- The primary seal must have sufficient thickness (greater than 20 feet [6 meters]), be regionally extensive, and be continuous over the entire projected CO_2 plume area after injection of 55 million tons (50 MMT) of CO_2.
- The primary seal must also have sufficiently low vertical permeability and have sufficiently high capillary entry pressure to provide a barrier to the migration of CO_2 out of the target formation.
- The proposed target formation(s) must not be an underground source of drinking water.
- The offeror must own or have a demonstrated ability to obtain, purchase, or obtain a waiver of subsurface mineral rights within and immediately adjacent to proposed target formation(s) to accommodate an injection capacity of 55 million tons (50 MMT) of CO_2.
- In addition to the required total storage capacity of the site, the proposed target formation(s) also must support a minimum CO_2 injection rate goal of 1.1 million tons (1 MMT) of CO_2 per year for up to 50 years.
- The proposed target formation(s) must not intersect marine shorelines or other major surface bodies of water. The bottomhole location of any injection well must be no closer than 10 miles (16 kilometers) to marine shorelines and major surface water bodies.
- Land above the proposed target formation(s) must not intersect large dams, water reservoirs, hazardous materials storage facilities, Class 1 injection wells, or other sensitive features. The bottomhole location of any injection well must be no closer than 10 miles (16 kilometers) to any sensitive feature.
- The primary seal must not be intersected by any known historically active or hydraulically transmissive faults.
- The proposed power plant site must have low risk from significant seismic events.

- The land above the proposed target formation(s) must not be on a public access area. The bottomhole location of any injection well must be no closer than 10 miles (16 kilometers) from any public access area (FG Alliance, 2006a).

The underground injection of CO_2 would be regulated under the U.S. Environmental Protection Agency's (EPA's) Underground Injection Control (UIC) Program. The UIC Program works with state and local governments to oversee underground injection of waste in an effort to prevent contamination of drinking water resources. All injection wells require authorization under general rules or specific permits. Many states, including Illinois and Texas, have primary enforcement responsibility (primacy) for the UIC Program. It is likely that the FutureGen Project ***CO_2*** injection wells would be treated as Class V (experimental) wells under the UIC Program. ***Additionally, extracted salt water (brine) would be reinjected underground through Class I disposal wells, unless the brine is used in association with oil or natural gas production where Class II wells could be used.***

Fate and Transport of Injected CO_2

Injection of CO_2 in its supercritical state into a deep geologic formation would be achieved by pumping the CO_2 down an injection well. The injected CO_2 would displace the existing saline water occupying the formation's pore space. Without this displacement, CO_2 could only be injected by increasing the formation's fluid pressure, which could result in formation fracturing. If a formation's fluid pressure is too high, the sequestration process may require installation of extraction wells that remove water from the formation.

To increase the storage potential, CO_2 would be injected into deep formations where it could maintain its dense supercritical state. The fate and transport of CO_2 in the formation would be influenced by the injection pressure, dissolution in the formation water, and upward migration due to CO_2's buoyancy.

> **Dissolution** is the process of a liquid dissolving into another liquid.
>
> **Miscible** refers to the property of liquids that allows them to be mixed together and form a single homogeneous phase.

Injection would raise the fluid pressure near the well allowing CO_2 to enter the pore spaces initially occupied by the saline water within the formation. Once injected, the spread of CO_2 would be governed by the following primary flow, transport and trapping mechanisms:

- Fluid flow (migration) in response to pressure gradients created by the injection process;
- Fluid flow (migration) in response to natural groundwater flow;
- Buoyancy caused by the density differences between CO_2 and the groundwater;
- Diffusion;
- Dispersion and fingering (localized channeling) caused by formation heterogeneities and mobility contrast between CO_2 and the groundwater;
- Dissolution into the formation groundwater or brine;
- Mineralization;
- Pore space trapping; and
- Adsorption of CO_2 onto organic material.

The magnitude of the buoyancy forces that drive vertical flow depends on the type of fluid in the formation. When CO_2 is injected into a deep saline formation in a liquid or liquid-like supercritical dense phase, it is only somewhat miscible in water. Because supercritical CO_2 is much less viscous than water (by an order of magnitude or more), it would be more mobile and could migrate at a faster rate than the saline groundwater. In saline formations, the comparatively large density difference (30 to 50 percent) creates strong buoyancy forces that could drive CO_2 upwards.

To provide secure storage (e.g., structural trapping), a low permeability layer (caprock) would act as a barrier and cause the buoyant CO_2 to spread laterally, filling any stratigraphic or structural trap it encounters. As CO_2 migrates through the formation, it would slowly dissolve in the formation water. In systems with slowly flowing water, reservoir-scale numerical simulations show that, over tens of years, up to 30 percent of the injected CO_2 would dissolve in formation water. Larger basin-scale simulations suggest that, over centuries, the entire CO_2 plume would dissolve in formation water. Once CO_2 is dissolved in the formation water, it would no longer exist as a separate phase (thereby eliminating the buoyant forces that drive it upwards), and it would be expected to migrate along with the regional groundwater flow.

Supercritical CO_2 - CO_2 usually behaves as a gas in air or as a solid in dry ice. If the temperature and pressure are both increased (above its supercritical temperature of 88ºF [31.1ºC] and 73 atmospheres [1,073 psi]), it can adopt properties midway between a gas and a liquid, such that it expands to fill its container like a gas, but has a density like that of a liquid.

As migration through a formation occurs, some of the CO_2 would likely be retained in the pore space, commonly referred to as "residual CO_2 trapping." Residual trapping could immobilize large amounts of the CO_2. While this effect is formation-specific, researchers estimate that 15 to 25 percent of injected CO_2 could be trapped in pore spaces, although over time much of the trapped CO_2 dissolves in the formation water (referred to as "dissolution trapping"). The dissolved CO_2 would make the formation water more acidic, with pH dropping as low as 3.5, which would be expected to dissolve some mineral grains and mineral cements in the rock, accompanied by a rise in the pH of the formation water. At that point, some fraction of the CO_2 may be converted to stable carbonate minerals (mineral trapping), the most permanent form of geologic storage. Mineral trapping is believed to be comparatively slow, taking hundreds or thousands of years to occur (IPCC, 2005).

To ensure the safe storage of sequestered CO_2, a monitoring and mitigation strategy would be implemented. The purposes of monitoring include assessing the integrity of plugged or abandoned wells in the region; calibrating and confirming performance assessment models; establishing baseline parameters for the storage site to ensure that CO_2-induced changes are recognized; detecting microseismicity associated with the storage project; measuring surface fluxes of CO_2; and designing and monitoring remediation activities. During the DOE-sponsored activities, a suite of monitoring approaches would be used to verify the safe containment of the CO_2 in the formation. Potential monitoring methods are described in Section 2.5.2.2.

Potential Leakage Pathways

A leading concern regarding geologic sequestration is the potential leakage of sequestered CO_2 from underground formations into the atmosphere or into an ***underground source of drinking water***. The mechanisms for leakage are highly dependent on the storage formation's geologic conditions. Pathways and mechanisms for leakage can include:

- Failure of seals near the borehole (due to corrosion of the formation rock, the casing, or the cement between the casing and the formation);
- Leakage through abandoned boreholes and wells;
- Migration of CO_2 through the caprock formation due to its innate permeability;
- Failure of the caprock by formation stress and fluid pressure changes from injection; and
- Failure of the caprock by external forces such as tectonic movement, stress caused by subsidence, or earthquakes.

Overall, the main risks of leakage of geologically sequestered CO_2 are due to well borehole leakage and caprock failure. Under the Proposed Action, ***perhaps in connection with the Area of Review requirements for a UIC permit,*** the Alliance would identify, plug and abandon (***as indicated by the State***

or Federal UIC Director) existing unused wells and boreholes that penetrate the primary seals of the injection reservoir. The Alliance conducted a search for such wells at each of the sites and their presence relative to the storage formation was addressed in the Risk Assessment (TetraTech, 2007) that was prepared in support of this EIS. Risks associated with other leakage pathways, such as migration through caprock and failures caused by external forces are expected to be small because the alternative sites have met the geologic and seismic criteria developed for the FutureGen Project.

Pathways that could be created through the execution of the project, such as failures of the injection well casing or caprock failure due to injection pressure, could be avoided or minimized through preparatory and operational measures (see Section 2.5.2.2). The risk assessment prepared for this EIS considers potential leakage scenarios from the subsurface and estimates the risks to groundwater quality, biota, and humans (see Section 2.5.4).

Reservoir Modeling of Injected CO_2

Predictions of the distribution of CO_2 injected into the saline formations at the alternative sites were made using numerical simulation performed at DOE's Pacific Northwest National Laboratory (PNNL). This simulation involves the solution of mathematical equations that describe the migration and properties of CO_2 as it is injected into the subsurface. The flow and transport equations address parameters such as viscosity, solubility, relative permeability, and density. For numerical simulations performed for the proposed injection of CO_2, the Alliance used a model called Subsurface Transport Over Multiple Phases (STOMP), which was developed at PNNL. The model is a general-purpose tool for simulating subsurface flow and transport and addresses a variety of subsurface environments and flow mechanisms. Since its creation, the STOMP program has been validated by comparing its results against laboratory-scale experiments and field-scale demonstrations. PNNL used the STOMP-CO_2 version of the model to simulate the CO_2 injection and dispersion at the sites.

> **Viscosity** is a material's resistance to flow.
>
> **Solubility** is the ability or tendency of one substance to dissolve into another at a given temperature and pressure.
>
> **Permeability** indicates the rate at which fluids would flow through the subsurface and reflects the degree to which pore space is connected.
>
> **Density** is the ratio of the weight of a substance relative to its volume.

> **STOMP** model documentation and information can be found at:
> - http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/p36.pdf
> - http://www.princeton.edu/~cmi/events/Workshop%20Summary%202005.pdf

Each alternative Site Proponent provided PNNL and the Alliance a data package containing detailed information on the geological, geochemical, hydrological, tectonic, and other physical properties of the planned injection site's subsurface environment. Where information from a third-party source was used, the source was documented to ensure traceability. Much of the subsurface data for the sites were provided by state or university sources (e.g., Bureau of Economic Geology [University of Texas], Illinois State Geologic Survey).

An important component of executing a numerical simulator is documenting the sources of inputs and cataloging the results. PNNL created a FutureGen Application Log to maintain these records to allow external reviewers to understand the data path from the site-specific data to the simulator inputs and allow the simulations to be replicated in the future.

Two scenarios were considered as representing reasonable bounds on the expected CO_2 output and sequestration operations for the FutureGen Project. Although CO_2 output depends on many factors, such as the coal type being gasified, the probable upper bound would be 7,551 tons (6,850 metric tons) per day, which results in an annual injection rate of 2.8 million tons (2.5 MMT) per year (assuming 100 percent operation over an entire year). Therefore, the first scenario modeled assumed this maximum injection case. A second case analyzed a constant injection rate of 1.1 million tons (1 MMT) per year, corresponding to the minimum rate of sequestration to be met over the first 4-year operating period. For both scenarios, a total of 55 million tons (50 MMT) of CO_2 would be injected into the target formation. This maximum quantity is based on the requirement set forth in the RFP for candidate sites.

To achieve an injection target of 55 million tons (50 MMT) of CO_2, an injection period of 20 years was used for the 2.8 million tons (2.5 MMT) per year scenario, and an injection period of 50 years was used for the 1.1 million tons (1 MMT) per year scenario. However, the reservoir model was run for 50 years in both cases. For all the sites except Jewett, the largest plume radius predicted by the numerical modeling was associated with the injection of 1 MMT for 50 years. As a result of the modeling, it is estimated that the largest plume radius at Jewett would be associated with the injection of 2.8 million tons (2.5 MMT) for 20 years, followed by 30 years of gradual plume spreading. These differences in plume size are due to site-specific geologic conditions.

DOE assessed impacts to environmental resources based on the plume footprint at each site. Predicted plume radii for each site are provided as part of the site descriptions in Section 2.4. The plume radius is defined as the radius within which 95 percent of the gas-phase CO_2 mass occurs.

Computer simulations of plume behavior were based on the best available data, which would be supplemented with additional data collection at the chosen site, should the project proceed. For purposes of analysis in this EIS, plume radii were calculated by defining the radius as the radial distance from the injection well within which 95 percent of the CO_2 mass would be contained. The 95 percent cutoff was used to ensure that the reported plume radii represented the bulk of the injected CO_2. The model results showed thin layers "stringer layers" of CO_2 that advanced ahead of the main plume due to high-permeability zones interpreted from well log data. These "stringers" account for a very small fraction of the injected CO_2; neither the existence or extent of such high-permeability zones at each site is known. Hence, use of the 95 percent cutoff prevented these stringers from unrealistically inflating the plume radius calculations in a way that would not be justified by the available reservoir data. Because permeability values for different horizontal directions or at different locations in the area were available, the reservoir model resulted in a circular plume based on the assumption that permeability values were constant horizontally. However, under real-world conditions, there are various factors that would cause the injected plume of CO_2 to be non-circular in shape (plan view or footprint) or larger or smaller than has been predicted here. If the permeability of the rock differs as a function of direction (e.g., less in an east-west direction than in a north-south direction), the plume would have an elliptical (oval) shape instead of a circular shape. Variations in the permeability of the rock over short distances within the formation may also cause the plume to take an irregular shape. Similarly, if the formation has a network of moderately to poorly connected fractures, the plume could follow these fractures, resulting in irregular flow paths.

Although limited data on directional permeability can be obtained through a single well core, three or more nearby wells would be required to estimate directional permeability. Drilling and testing such deep wells would be exorbitantly expensive if done for all four sites and it is unlikely to be essential to site selection.

The size and shape of the plume would also be a function of pressure forces between the formation and injected CO_2. While real-world injections require the regulation of fluid pressure buildup to prevent fracturing of the overlying caprock or seals, the computer simulations did not explicitly account for pressure-induced effects on the target formation or overlying caprock (i.e., geomechanical modeling was not included in the simulations). Most likely, failure to include geomechanical effects causes small errors in the simulation results that would not affect site selection.

While dissolution and buoyancy effects were considered in the plume model, natural flow of the native fluids in the reservoirs was not considered. Natural flow rates are usually extremely slow and in most situations would not be a concern. Dip (or inclination) of the strata is low (generally a few degrees) at each of the four sites and was not considered in the simulations as an influence on plume migration under buoyant forces. Furthermore, the size of the plume would be a function of various chemical reactions with the reservoir rock and native fluids, such as mineralization which occurs over hundreds of years. Geochemical effects, other than salt precipitation, were not considered in the calculations of the plume radii used in this EIS.

2.5.2.2 Monitoring, Mitigation, and Verification

The Alliance would rigorously monitor the sequestration efforts, including conditions in the proposed target formation as well as conditions in overlying strata, soil, groundwater supplies, and air. The comprehensive monitoring program would likely include installation of monitoring wells in strategic locations around the injection site in addition to atmospheric and shallow subsurface monitoring stations.

MM&V encompasses the process for ensuring the safe and permanent storage of sequestered gases. Injection of CO_2 into the subsurface would be regulated under EPA's UIC program. Monitoring would help to satisfy the protection requirements under the UIC program and would be used for a number of purposes, including but not limited to:

- Tracking the location of the plume of injected CO_2;
- Ensuring that the injection well and any monitoring wells or abandoned wells in the area are not leaking; and
- Verifying the quantity of CO_2 that had been injected.

MM&V is the capability to measure the amount of CO_2 stored at a specific sequestration site, to monitor the site and mitigate the potential for leaks or other deterioration of storage integrity over time, and to verify that the CO_2 is being stored and is not harmful to the host ecosystem.

MM&V relevant to geologic sequestration can be divided into three broad categories of subsurface, soils, and the overlying air. Subsurface MM&V would involve tracking the fate of the injected CO_2 within the geologic formation and possible migration or leakage to the surface. Soil MM&V would involve detecting CO_2 in the first several feet of topsoil and tracking potential leakage pathways into the atmosphere. Methods to track CO_2 leaking to the atmosphere are challenging due to the difficulty in detecting small changes in CO_2 concentration above background concentrations that already exist in the atmosphere. However, tracers could be added to injected CO_2 to aid the monitoring process. These tracer chemicals can easily be measured at monitoring wells, are not commonly found in nature, do not rapidly degrade or interact with compounds in the formation, and exhibit low toxicity to biota.

The Alliance would monitor the injected CO_2 with methods that continuously measure or record data as well as methods that are conducted periodically. In general, the sampling and measurement frequency would be higher during the active injection period and would decrease afterwards. Baseline data would be collected during the year preceding injection. In terms of DOE's research program, the total monitoring timeline ***includes*** 1 year of baseline data collection, ***4*** years of active injection, and 2 years of post-injection monitoring. The monitoring scheme would be tailored to the characteristics of the site. If the CO_2 injection operation continues past the research phase, the Alliance or its successor would continue basic monitoring until sometime after the injection stops in accordance with UIC regulations and applicable permit conditions.

A preliminary schedule of monitoring during the first 6 years is provided in Table 2-6. Full descriptions of these techniques are found in the site Environmental Information Volumes (EIVs) (FG Alliance, 2006b, c, d, e). The Alliance may change the types and frequencies of monitoring activities after the initial research and testing phase of the project. As part of the Cooperative Agreement, at the end of the 4-year operating period, the Alliance would be obligated to prepare a plan, which is mutually acceptable to DOE, to address the extent of continued monitoring of the sequestered CO_2. On March 23, 2007, the Full Scope Cooperative Agreement was signed by both parties. Because the FutureGen Project is a research project, the Alliance may use some new and experimental monitoring methods, in addition to those listed in Table 2-6, to determine the fate and transport of the injected CO_2.

Table 2-6. Preliminary Schedule of Possible FutureGen Project CO_2 Plume Monitoring Activities

	Baseline	Active Injection				Post Injection	
Time (Years)	**-1**	**1**	**2**	**3**	**4**	**5**	**6**
Injection System Monitoring							
Supervisory Control and Data Acquisition (SCADA) Monitoring of Injection Wells (Pressure, Temperature, Flow Rate)	n/a	**CONTINUOUS**					
Remote Sensing							
Light Detection and Ranging (LiDAR) Survey	**X**	**X**	**X**	**X**	**X**		**X**
Atmospheric Monitoring							
Eddy Covariance	**CONTINUOUS**						
Near Surface Monitoring							
Soil Gas Monitoring	**XX**	**X**	**X**	**X**	**X**		**X**
Surface Flux Emissions	**XX**	**X**	**X**	**X**	**X**		**X**
Vehicle Mounted CO_2 Leak Detection System	**X**	**XXXX**	**XXXX**	**XXXX**	**XXXX**	**X**	**X**
CO_2 Surface Well Monitoring	**CONTINUOUS**						
Borehole Tiltmeters	**CONTINUOUS**						
Subsurface Monitoring							
In-Situ Pressure/Temperature Monitoring (Injection Reservoir)	**CONTINUOUS**						
Fluid Sampling–Drinking Aquifer Monitoring Wells	**X**	**XX**	**XX**	**XX**	**XX**	**X**	**X**
Fluid Sampling–Primary Seal Monitoring Wells	**X**	**XX**	**XX**	**XX**	**XX**		**X**
Fluid Sampling–Injection Reservoir Monitoring Wells	**X**	**XX**	**XX**	**XX**	**XX**		**X**
Crosswell Seismic	**X**	**X**	**X**	**X**	**X**		**X**
Wireline Logging/Coring	**X**	**X**	**X**	**X**	**X**		**X**
Downhole Microseismic	**CONTINUOUS**						
Surface Seismic (2D,3D)	**X**	**X**	**X**		**X**		**X**

X = single monitoring event per year; XX = semi-annual monitoring; XXXX = quarterly monitoring; n/a = not applicable.
Source: FG Alliance, 2007***b***.

Although the classification of UIC wells would be determined at the time of permitting, there is an overall standard of protection under the UIC Program that prohibits the movement of fluids into underground sources of drinking water. The citation below (from 40 CFR Part 144) provides the standard that all injection wells must be measured, including Class V (shallow and other) wells. This standard is currently in effect:

§ 144.12 Prohibition of movement of fluid into underground sources of drinking water.

(a) No owner or operator shall construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or may otherwise adversely affect the health of persons. The applicant for a permit shall have the burden of showing that the requirements of this paragraph are met.

Furthermore, if any water quality monitoring of underground sources of drinking water indicates the movement of any contaminant into the water source, the state or EPA would require corrective action, operation, monitoring, or reporting as necessary to prevent such movement. The injection permit would be modified to reflect these additional requirements or the permit may be terminated. Appropriate enforcement action can be taken if a permit is violated.

Continuous Monitoring Methods

A Supervisory Control and Data Acquisition (SCADA) system would continuously monitor and transmit flow rate, pressure, and temperature information from the injection wells to a central data collection point. An Eddy Covariance tower(s) would measure atmospheric CO_2 concentrations over a large area using an infrared gas analyzer and measure local meteorological variables such as wind velocity, relative humidity, and temperature. Using detectors installed at the wellheads, continuous CO_2 monitoring would also be conducted at existing wells that are within a predicted five-year plume footprint and that penetrate into the injection reservoir. An array of borehole micro-tiltmeters would be installed in shallow (25 foot [7.6 meter]) boreholes arranged in transects extending away from each injection well to the edge of the five-year plume footprint. The micro-tiltmeters would continuously record measurable changes in surface tilt from the CO_2 plume. Monitoring wells would be installed that contain instrumentation for continuously monitoring and recording fluid pressure and temperature in or above the injection reservoir. Additional monitoring wells would be drilled to the top of the primary seal and would house a permanent microseismic array for monitoring faint earth tremors (microseisms).

Quarterly Monitoring Methods

On a quarterly basis (see Table 2-6), the Alliance would use a vehicle-mounted CO_2 leak detection system equipped with a global positioning system. This system would monitor atmospheric concentrations overlying the area of the plume and allow real-time leak detection and mapping over broad areas.

Semi-Annual Monitoring Methods

Fluid sampling from various monitoring wells would occur twice each year during the 4-year active injection period (research and development phase of the project). Fluid would be sampled from above the primary seal and in the reservoir. Fluid samples would be submitted to a laboratory for the following analyses: anions; carbonate and total alkalinity; metals; gases (methane, ethane, CO_2, CO, nitrogen gas); salinity; and stable isotopes.

Annual Monitoring Methods

A Light Detection and Ranging (LiDAR) survey would be conducted annually during the period that DOE would sponsor the FutureGen Project. LiDAR is an aerial technique that uses ***laser*** pulse travel times from an aircraft to the land surface to obtain high resolution topography data. The data would be used to detect changes in surface elevation that could occur due to subsurface CO_2 injection and movement. Additionally, soil gas probes would be installed annually along transects extending away from the injection well(s) and would be analyzed for CO_2, perfluorocarbon tracers, and stable carbon and O_2 isotopes. These soil gas probes help to detect leaks from the storage reservoir. Surface flux measurements would be conducted in a similar array as the soil gas probes and would aid in distinguishing a release of CO_2 from the injection reservoir from background CO_2.

The Alliance would annually conduct crosswell seismic imaging, which is a geophysical technique that creates a two-dimensional (2D) image in a vertical plane through the CO_2 plume between pairs of wells. Sources and receivers are placed in wells completed in the injection reservoir to allow the best measurement of changes in rock properties (such as the velocity of seismic signals) that are affected by the presence of CO_2. Similarly, wireline logging would be conducted whereby various sensors are lowered and raised inside a well to collect information about CO_2 saturation in rock surrounding the well. Other devices can be lowered into a well to collect rock-core samples for geochemical and geomechanical analyses. This technique can yield information about the mechanical integrity of the well bores and can verify the interpretation of data from wireline logging.

The Alliance would also conduct seismic imaging to create 2D or three-dimensional (3D) images of the CO_2 plume by measuring changes in rock properties such as seismic velocity that are affected by the presence of CO_2. Seismic imaging uses either large vibroseis trucks weighing up to 56,000 pounds (25,401 kilograms), with heavy steel vibrators on them, or small explosives (often detonated in shallow boreholes) to produce seismic signals. This is done along potentially hundreds of "shot" points along lines that are surveyed across the study area. The vibrations caused at the surface travel downward and reflect from geologic layers and features, which cause echoes or reflections that travel back up to the land surface. Electromagnetic transducers, or geophones, detect the echoes and convert them into electrical signals. These signals are then processed into images of the subsurface.

Although leakage would not be expected, operators of the injection site(s) would need to be prepared to address a leak if one occurs. Active or abandoned wells (including the injection wells themselves) are potential pathways, and identifying options for remediating leakage of CO_2 from these pathways is especially important.

Similar to occurrences in oil and gas extraction wells, a blow-out could occur at the injection wellhead. Stopping blow-outs or leaks from injection wells or abandoned wells could be accomplished using standard oil field techniques (one such method is to inject a heavy mud into the well casing). If access to the well head is not safe or possible, heavy mud could still be introduced into the well by drilling a new well that would intercept the casing below the ground surface, and then mud would be pumped through this interception well and into the injection well. After control of the well is re-established, the well could either be repaired or abandoned.

Leaking injection wells could be repaired by replacing the injection tubing and packers. If the annular space behind the casing was leaking, the casing could be perforated to allow injection of cement behind the casing until the leak was stopped. If the well could not be repaired, it would be sealed and abandoned using established methods. Table 2-7 provides an overview of remediation options for typical leakage scenarios.

Table 2-7. Remediation Options for Geological CO_2 Storage Projects

Scenario	Remediation Options
Leakage up faults, fractures, and spill points	• Lower injection pressure by injecting at a lower rate or through a larger number of wells. • Lower reservoir pressure by removing water or other fluids from the storage structure. • Intersect the leakage with extraction wells in the vicinity of the leak. • Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak. • Lower the reservoir pressure by creating a pathway to access new compartments in the storage reservoir. • Stop injection to stabilize the project. • Stop injection, produce the CO_2 from the storage reservoir, and reinject it back into a more suitable storage structure.
Leakage through active or abandoned wells	• Repair leaking injection wells with standard well re-completion techniques such as replacing the injection tubing and packers. • Repair leaking injection wells by squeezing cement behind the well casing to plug leaks behind the casing. • Plug and abandon injection wells that cannot be repaired by the methods listed above. • Stop blow-outs from injection or abandoned wells with standard techniques to 'kill' a well such as injecting a heavy mud into the well casing. After control of the well is re-established, the recompletion or abandonment practices described above can be used. If the wellhead is not accessible, a nearby well can be drilled to intercept the casing below the ground surface and 'kill' the well by pumping mud down the interception well.
Accumulation of CO_2 in the vadose zone and soil gas	• Accumulations of gaseous CO_2 in groundwater can be removed or at least made immobile, by drilling wells that intersect the accumulations and extracting the CO_2. The extracted CO_2 could be vented to the atmosphere or reinjected back into a suitable storage site. • Residual CO_2 that is trapped as an immobile gas phase can be removed by dissolving it in water and extracting it as a dissolved phase through a groundwater extraction well. • CO_2 that has dissolved in the shallow groundwater could be removed, if needed, by pumping to the surface and aerating it to remove the CO_2. The groundwater could then either be used directly or reinjected back into the groundwater. • If metals or other trace contaminants have been mobilized by acidification of the groundwater, 'pump-and-treat' methods can be used to remove them. Alternatively, hydraulic barriers can be created to immobilize and contain the contaminants by appropriately placed injection and extraction wells. In addition to these active methods of remediation, passive methods that rely on natural biogeochemical processes may also be used.
Leakage into the vadose zone and accumulation in soil gas	• CO_2 can be extracted from the vadose zone and soil gas by standard vapor extraction techniques from horizontal or vertical wells. • Fluxes from the vadose zone to the ground surface could be decreased or stopped by caps or gas vapor barriers. Pumping below the cap or vapor barrier could be used to deplete the accumulation of CO_2 in the vadose zone. • Because CO_2 is a dense gas, it could be collected in subsurface trenches. Accumulated gas could be pumped from the trenches and released to the atmosphere or reinjected back underground. • Passive remediation techniques that rely only on diffusion and 'barometric pumping' could be used to slowly deplete one-time releases of CO_2 into the vadose zone. This method would not be effective for managing ongoing releases because it is relatively slow. • Acidification of the soils from contact with CO_2 could be remediated by irrigation and drainage. Alternatively, agricultural supplements such as lime could be used to neutralize the soil.

Table 2-7. Remediation Options for Geological CO_2 Storage Projects

Scenario	Remediation Options
Large releases of CO_2 to the atmosphere	• For releases inside a building or confined space, large fans could be used to rapidly dilute CO_2 to safe levels. • For large releases spread out over a large area, dilution from natural atmospheric mixing (wind) would be the only practical method for diluting the CO_2. • For ongoing leakage in established areas, risks of exposure to high concentrations of CO_2 in confined spaces (e.g., cellar around a wellhead) or during periods of very low wind, fans could be used to keep the rate of air circulation high enough to ensure adequate dilution.
Accumulation of CO_2 in indoor environments with chronic low-level leakage	• Slow releases into structures can be eliminated by using techniques that have been developed for controlling release of radon and volatile organic compounds (VOCs) into buildings. The two primary methods for managing indoor releases are basement/substructure venting or pressurization. Both would have the effect of moving soil gases away from the indoor environment.
Accumulation in surface water	• Shallow surface water bodies that have significant turnover (shallow lakes) or turbulence (streams) will quickly release dissolved CO_2 back into the atmosphere. • For deep, stably stratified lakes, active systems for venting gas accumulations have been developed and applied at Lake Nyos and Monoun in Cameroon.

Source: IPCC, 2005.

2.5.3 RISK ASSESSMENT OF LEAKAGE OF CAPTURED GASES BEFORE GEOLOGIC SEQUESTRATION

One of the distinguishing aspects of the FutureGen Project is the capture of CO_2 (and other gases) from the gasification process. While there are existing power plants that capture CO_2, a FutureGen Project goal is to demonstrate the integration of CO_2 capture with a state-of-the-art IGCC power plant. The FutureGen Project would also provide a test bed for newer capture technologies, such as membranes that can separate H_2 from other gases, including CO_2. Because CO_2 capture technologies do pose some risks not commonly found in power plants, DOE assessed the risks and hazards of alternative capture technologies and pipeline transmission of captured gases. DOE worked with nationally recognized experts in relevant fields (e.g., natural gas transmission engineering, pipeline design, and EOR) to develop and apply its risk assessment methodology (see Appendix D). The results of this risk assessment are incorporated in this EIS.

2.5.4 RISK ASSESSMENT OF LEAKAGE OF SEQUESTERED GASES FROM GEOLOGIC RESERVOIRS

A key objective of the FutureGen Project is to verify the effectiveness, safety, and permanence of CO_2 stored in geologic formations. Because geologic sequestration of CO_2 in deep saline formations is a relatively new endeavor in the U.S. and abroad, it is important to advance the understanding of the pathways and associated risks of potential leaks of CO_2 from geologic formations.

In general, standardized, well-accepted methods of assessing risks and impacts of the sequestered gases (CO_2 and any other captured gases) do not exist. To assess the potential environmental impacts of CO_2 sequestration, DOE developed a protocol and methods to assess the risks of both slow leaks (including contamination of groundwater supplies and surface water supplies by sequestered gases and by displaced native fluids) and catastrophic rapid releases of sequestered gases (e.g., a well blow out). Subsequently, DOE asked nationally recognized experts in relevant fields (e.g., reservoir simulation, EOR, natural gas storage field management, geochemistry, geophysics, and reservoir engineering) to review and provide input on the risk assessment methodology (see Appendix D). While the risk assessment has been performed as part of this EIS, it should be noted that after selection of the host site, the Alliance would undertake a more comprehensive evaluation of the sequestration site and target reservoirs. At that point, the Alliance would drill one or more exploratory wells and conduct more characterization of the risks and potential impacts. DOE then would evaluate the resulting information as part of its preparation of a Supplement Analysis to determine whether a Supplemental EIS would be required. The Risk Assessment Report is posted on the NETL website (http://www.netl.doe.gov/technologies/***EIS***) and is available on the ***Final*** EIS distribution CD.

2.5.5 RESOURCE REQUIREMENTS

2.5.5.1 Coal Requirements

The Alliance plans to test a variety of coal types during the DOE-sponsored 4-year operating period. While specific coal types and properties have yet to be selected, the conceptual design was developed based on representative properties for three common coal types: Northern Appalachia Pittsburgh coal, Illinois Basin coal, and PRB coal. These three coal types are broadly representative of eastern bituminous, mid-western bituminous, and western low-rank ***sub-bituminous*** coals***, respectively***. Because the FutureGen Project is a research and development effort of nation-wide (and world-wide) significance, it is desirable for the facility to incorporate a degree of fuel flexibility that would not necessarily be included in the design of a conventional power plant. After the 4-year operating period, the Alliance or its successor may choose a different type of coal or fuel type based on economic factors or continuing research needs.

The power plant would require up to 1.89 million tons (1.7 MMT) of coal per year. DOE assumed that coal would be delivered by rail to all the candidate sites because it is the most economically feasible option. For the purposes of analysis within this EIS, this assumption was used. Based on the type of coal, rail shipments would average five trains per week, with each train consisting of approximately 100 railcars.

2.5.5.2 Infrastructure Requirements

Alternative sites were selected based on a number of factors, including proximity to utilities such as electricity transmission, natural gas, water, and sewer lines. The FutureGen Project requires the ability to connect to the local electric grid, a potable water source (unless an on-site potable water treatment plant is constructed), a process water source, a natural gas supply, and a sanitary sewer (or construction of a packaged system on site). The Alliance may construct a holding pond or reservoir on site to store process water to meet water requirements. Connection to the electric grid may require the construction of additional transmission lines, installation of new electrical substations, or upgrades to existing substations. Furthermore, electricity would be needed at the CO_2 injection sites to power pumps, compressors, and monitoring equipment. New utility lines may require new easements and ROWs or the expansion of existing ROWs. The utilities available and method of interconnection would be dependent on the characteristics of the site location.

The FutureGen Project would include the construction and operation of a research and development facility to be co-located on the power plant site. The scope of activities that would occur at this facility has not yet been determined. The plant may also include an on-site Visitor Center, where the public and invited guests could learn about the plant and its technologies through displays and possibly interactive exhibits.

2.5.5.3 Natural Gas Requirements

During gasifier unplanned restart, natural gas-fired burners would heat the gasifier to a temperature sufficiently high to initiate coal feed and gasification. Exhaust gas from the natural gas-fired burners would be vented to the flare stack. The frequency of restarts would depend upon the research and development needs, the rate of plant upsets, and how often coal types are changed. During a restart event, natural gas would be used at a rate of up to 1.8 million cubic feet per hour (50,970 cubic meters per hour). During restarts, natural gas would primarily be required for warming up the gasifier (up to 4 hours) and the combustion turbine (up to 2 hours).

2.5.5.4 Process Water Requirements

The plant would consume up to 3,000 gallons (11,356 liters) per minute of water. The cooling tower system would account for most of this water requirement. Other uses of water at the power plant would include coal handling (slurry preparation and dust suppression) and replacement of HRSG blowdown water.

Water would be required at the sequestration sites during construction to support the drilling of injection and monitoring wells. As this is a short-duration activity, DOE assumes that water would be trucked to the site for this purpose. Water would also be required for integrity testing of the new CO_2 pipelines before the start of sequestration activities. This testing would occur before the operational phase. The water could be supplied from the power plant site's proposed process water source or it could be supplied by tanker truck.

2.5.5.5 Transportation Requirements

All the sites are bordered by existing freight railroad lines. Rail transportation would be used for coal and other shipments to the site. A rail loop and siding on the property would be constructed to allow trains with approximately 100 railcars to exit the mainline and load and unload shipments within the plant boundary (see Figure 2-18). In addition, all of the candidate sites would be accessible by roads and highways to allow for other deliveries of products and materials to and from the plant site, as well as to facilitate commuting for workers.

2.5.5.6 Land Area Requirements

To allow adequate land area for the FutureGen Power Plant, coal storage, potential rail loop and siding, employee parking, potential research and development activity, possible on-site storage of slag, and other supporting structures, the Alliance estimates up to 200 acres (81 hectares) of land would be required. Easements and ROWs would also be required for new or expansions of existing utility, road, and rail corridors.

Land or easements would also be needed for injection wells, monitoring wells, and other supporting infrastructure at the sequestration site. The amount needed would depend on the geologic attributes of the sequestration reservoir, and for MM&V purposes, the projected size of the plume. However, it is expected that the disturbance footprint for these corridors would be up to than 10 acres (4 hectares) (either contiguous or noncontiguous).

2.5.6 DISCHARGES, WASTE, AND PRODUCTS

2.5.6.1 Air Emissions

IGCC power plants that are currently in operation have achieved the lowest levels of criteria air pollutant, Hg and other hazardous air pollutants (HAPs) emissions of any coal-fueled power plant technologies (DOE, 2002). The six criteria air pollutants are sulfur dioxide (SO_2), CO, ozone, nitrogen dioxide (NO_2), lead (Pb), and inhalable particulates, which are also known as respirable particulate matter (PM). The PM_{10} standard covers particles with diameters of 10 micrometers or less and the $PM_{2.5}$ standard covers particulates with diameters of 2.5 micrometers or less. Ozone is not emitted directly from a combustion source. It is formed from photochemical reactions involving emitted VOCs and NO_X. Table 2-8 provides FutureGen Project performance targets for air emissions compared with DOE's Fossil Energy Clean Coal Power Initiative (CCPI) targets.

Table 2-8. FutureGen Project Performance Targets

Pollutant	FutureGen Performance Targets (by 2016)[1]	DOE's Fossil Energy CCPI Targets (by 2020)
SO	>99 percent sulfur removal [2] (0.032 lb [0.015 kg]/10^6 Btu) [3, 4]	>99 percent sulfur removal
NO_X	<0.05 lb [0.02 kg]/10^6 Btu	<0.01 lb (0.005 kg)/10^6 Btu
PM_{10}	<0.005 lb [0.002 kg]/10^6 Btu	<0.002 lb (0.001 kg)/10^6 Btu
Hg	> 90 percent Hg removal (≤0.611 lb [0.277 kg]/10^{12} Btu)[4]	95 percent Hg removal
CO	n/a [5, 6]	n/a [6]

Table 2-8. FutureGen Project Performance Targets

Pollutant	FutureGen Performance Targets (by 2016)[1]	DOE's Fossil Energy CCPI Targets (by 2020)
VOC	n/a [6]	n/a [6]
Pb	n/a [5, 6]	n/a [6]
CO_2	>90 percent capture and sequestration	n/a [6]

[1] FutureGen facility operating at full load under steady-state conditions. ***Performance targets based on project goals identified in 2004 report to Congress (DOE, 2004).***
[2] Sulfur removal from feed coal.
[3] Based on the FutureGen Project performance target and calculated with AP-42 (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources) emissions factors.
[4] Mass emission rates are based on conceptual design coal properties and performance estimates. See Table 2-9 for tons per year estimates.
[5] No FutureGen Project Performance Target for Pb and CO; however, existing IGCC power plants have demonstrated CO emission levels of <0.033 lb (0.015 kg)/10^6 Btu and Pb emissions ranging from trace amounts to 2.9 lb (1.3 kg)/10^{12} Btu. Trace amounts means the pollutant is present in levels no greater than 1,000 ppm or <0.1 percent by weight.
[6] n/a = No performance target or no CCPI target.
Btu = British thermal unit; kg = kilogram.
Sources: DOE, 2002; DOE, 2006a; DOE, 2006b.

Geologic CO_2 sequestration would be a unique component of the FutureGen Project that would help significantly lower air emissions of CO_2. However, this project's feature adds to the capital cost of the plant and consumes some of the power plant's energy output, resulting in an overall decrease in the net efficiency of the power plant. Although the FutureGen Project is being developed to be the first near-zero-emissions coal power plant, low levels of air emissions would be generated by process units such as the gasifier, combustion turbines, and the cooling towers.

When switching between coals, performing certain tests, or experiencing a malfunction, the facility would need to be brought down to a reduced state of operations or perhaps be shut down completely. Upon restart, facility emissions would be higher than steady-state operations as process units are brought online and ramped up to optimum performance. In addition, due to the complexity of integrating advanced technologies, unexpected shutdowns are likely to occur. Associated with such unplanned restarts are short-term increases to facility emissions due to the need to flare process gases for a short period, as well as to restart the facility (i.e., unplanned restarts). The types of unplanned restarts and the frequencies of their occurrence are uncertain. Therefore, estimates for unplanned restarts over the life of the project were developed based on experience at existing IGCC facilities. DOE expects that, over time, learning and experience would reduce the frequency and types of unplanned restarts reflected in estimates shown in Table 2-9. DOE and the Alliance estimate that the first year of the research and development period would have the greatest number of unplanned restarts with 29 occurrences. Years 2, 3, and 4 are estimated to have 18, 14, and 13 unplanned occurrences, respectively.

The Alliance provided the FutureGen Project's estimate of maximum air emissions that would be expected from the facility. DOE has reviewed and verified that this estimate of maximum air emissions provides a reasonable upper bound for air emissions considered in the EIS. However, given the early stages of plant design, there is some uncertainty with these data. Table 2-9 compares the FutureGen Project's estimate of maximum air emissions (based on the predicted number of startups during the first year) with the performance target emission rates for the FutureGen Project. Because emissions of criteria pollutants are projected to exceed 100 tons per year, the FutureGen Project would be classified as a major source under Clean Air Act regulations.

Table 2-9. FutureGen Project Potential Air Emissions: FutureGen Project Estimated Maximum Air Emissions vs. Performance Target

Air Emissions	Initial Startup Emissions(2012)[1] (tpy [mtpy])	Planned Performance Target Emissions (2016 and beyond)[2] (tpy [mtpy])
SO_2	543 (493)	***100*** (***90.7***)
NO_2[3]	758 (688)	326 (296)
PM_{10}	111 (101)	33 (30)
Hg	1.1x10-2 (1.0x10^{-2})	0.4x10-2 (0.36x10^{-2})
CO	611 (554)	n/a[4]
VOC	30 (27)	n/a[4]
CO_2[5]	0.18 x 10^6 (0.17 x 10^6) up to 0.45 x 10^6 (0.41 x 10^6)	0.12 x 10^6 (0.11 x 10^6) up to 0.28 x 10^6 (0.25 x 10^6)

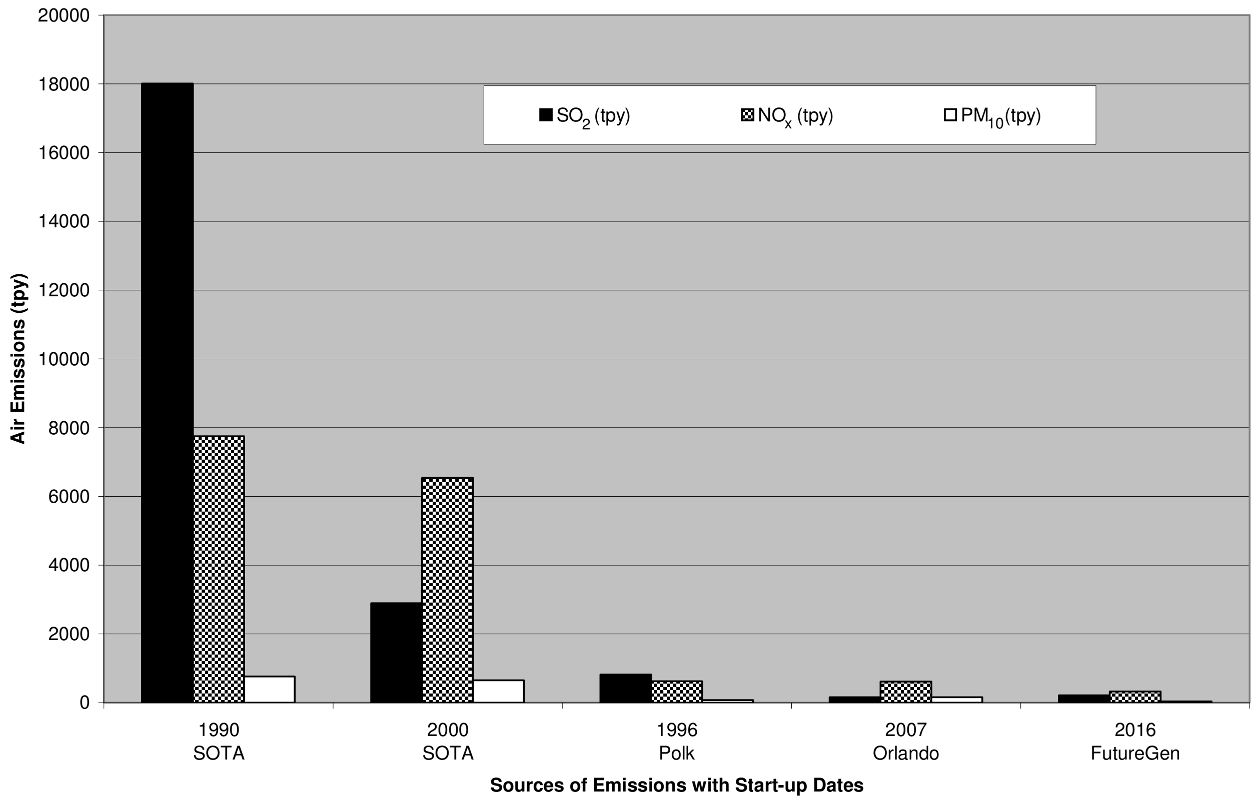
[1] Maximum emissions for the first year of operations and includes steady-state at 85 percent availability of facility plus unplanned restart emissions. First year of operations is estimated to have 29 unplanned outage events, the most of the 4-year research and development period. Year 2 would have 18; Year 3 would have 14; Year 4 would have 13.
[2] ***NO_2, PM_{10}, and Hg were c***alculated based upon ***FutureGen Project Performance Targets*** *(see Table 2-8).* ***Final technology configuration and design will dictate actual emissions. SO_2 was based on reduced unplanned outage events at the end of the 4-year research and development period (see Appendix E).*** Calculated at 85 percent availability of facility. Parameters are for "average" coal and average annual heat input rate of 1,754 million Btu/hour obtained from similar plants. Heat input at 70°F. "Average coal" estimates are based on the parameters averaged out for the three proposed coal types: PRB, Illinois Basin, and the Northern Appalachia Pittsburgh.
[3] ***NO_X emissions from coal combustions are primarily nitric oxide (NO); however, for the purpose of the air dispersion modeling it was assumed that all NO_X emissions are NO_2. One of the technologies being considered for the FutureGen Project is post-combustion selective catalytic reduction (SCR), which would reduce the annual NO_2 emissions in this base case to 252 tons per year (228.6 metric tpy).***
[4] n/a indicates that emission targets for these pollutants have not been established.
[5] Calculated based on maximum emissions of up to 2.5 MMT/year for 100 percent availability of facility and 1.0 MMT/year for less than 100 percent availability. The FutureGen Project's initial startup emissions assumes 85 percent capture and 15 percent release to the atmosphere. The FutureGen Project performance target emissions assumes 90 percent capture and 10 percent release to the air. ***Based on the worst case scenarios for coals, at startup in 2012, this equals between 114 lbs/MWhr to 243 lbs/MWhr of CO_2 emitted,and 647.20 lbs/MWhr to1,377.77 lbs/MWhr of CO_2 captured, depending on plant availability and less than 90 percent CO_2 capture. For 2016, when the R&D of the projects ends, it is assumed 90 percent capture and 10 percent emitted into the atmosphere; therefore from 76.14 lbs/MWhr to 162.09 lbs/MWhr of CO_2 emitted depending on plant availability. Conversely, at 90 percent capture, this results in 685.3 lbs/MWhr to 1,458.9 lb/MWhr CO_2 captured.***
tpy = tons per year; mtpy = metric tons per year.
Source: FG Alliance, 2006g.

A key goal of the FutureGen Project is to improve power plant technology and reduce emission levels. Table 2-10 provides baseline emissions to show the differences in air emissions between the FutureGen Project performance targets for air emissions and existing IGCC power plants and non-IGCC state-of-the-art (SOTA) conventional pulverized coal-fueled power plants. Figure 2-21 illustrates how advancements in technology have reduced major criteria pollutants from power plants over time.

Table 2-10. Comparison of FutureGen Project Performance Target to Other IGCC and SOTA Power Plant Technologies (tpy [mtpy])

Air Emissions	2016 FutureGen Project[1] (275 MW)	2007 Orlando[2, 3] (275 MW)	1996 Polk[2, 4] (275 MW)	2000 SOTA[2, 5] (275 MW)	1990 SOTA[2, 6] (275 MW)
SO_2	***100*** (***90.7***)	155 (140)	821 (744)	2,891 (2,622)	18,013 (16,341)
NO_2	326 (296)	611 (554)	620 (562)	6,537 (5,930)	7,747 (7,028)
PM	33 (30)	159 (144)	75 (68.0)	653 (592.4)	758 (687.7)
Hg	0.004 (0.0036)	0.015 (0.0136)	0.017 (0.0154)	0.112 (0.1016)	0.103 (0.0934)
CO_2 (MMT/yr)	0.11 (0.10) to 0.28 (0.25)	1.80 (1.6)	1.37 (1.243)	4.47 (4.055)	6.22 (5.643)

[1] SO_2 ***emissions are calculated based on the reduced unplanned outage events after year 4. Unplanned outage events would result in higher SO_2 emissions at restart.*** NO_2, PM_{10}, and Hg emissions calculated from FutureGen Project Performance Target as presented in the Report to Congress using "average" coal with a heat input rate of 1,754 MMBtu/hr at 70°F (DOE, 2004). CO_2 calculated based on 90 percent capture and sequestration goal (FG Alliance, 2006g).
[2] Orlando Gasification Project (Orlando) and Tampa Electric Company Polk Power Station (Polk) planned and operating IGCC power plants, respectively, and the SOTA are conventional coal-fueled power plants.
[3] SO_2, NO_2, and Hg are based on emission limiting conditions in the Final PSD Permit (FLDEP, 2007a). PM_{10} emissions based on potential emissions from the combustion turbine/HRSG as reported in PSD Permit Application (FLDEP, 2007b). CO_2 emissions are projected based on estimates reported in Orlando Gasification Project Final EIS (DOE, 2007).
[4] SO_2 and CO_2 emissions are actuals reported for Acid Rain Program (EPA, 2007a). Hg emissions from limiting conditions in Title V permit (FLDEP, 2007c). NO_2 and PM emissions from limiting conditions in Title V permit modification (FLDEP, 2007d).
[5] SO_2 and CO_2 emissions are actuals reported for Acid Rain Program from Hayden, Routt, CO facility. NO_X are actuals reported for Acid Rain Program from E.D. Edwards, Peoria, IL facility. PM emissions calculated from rates obtained from DOE database for Hayden, Routt, CO facility. Hg emission factors and heat value as reported in EPA's *Locating and Estimating Air Emissions from Sources of Mercury and Mercury Compounds* (EPA, 1997).
[6] SO_2 and NO_2 emissions are actuals reported for Acid Rain Program from Meramac, St. Louis, MO facility. CO_2 emissions are actuals reported for Acid Rain Program from C G Allen, Gaston, NC facility. Hg emissions for 2005 as reported in EPA Envirofacts website from Cholla, Navajo, AZ facility. PM emissions calculated from rates obtained from DOE database for C G Allen, Gaston, NC facility (275 MW) that made modification in 1996.
MMT/yr = million metric tons per year; MW = megawatt.



tpy = tons per year.

Figure 2-21. Comparison of FutureGen Project Performance Target to Other IGCC and SOTA Power Plant Technologies

Emissions from the FutureGen Project would be lower than emissions from other IGCC power plants and SOTA coal plants**.** SO_2 emissions rates from the Orlando Gasification Project (Orlando) ***are comparable to FutureGen Project because*** this facility uses low sulfur PRB sub-bituminous coal. As a research platform, the FutureGen Project would use various types of coal with varying sulfur content.

The conceptual design of FutureGen, as presented in the Initial Conceptual Design Report (ICDR), does consider the application of SCR to achieve NO_x emission levels of approximately 0.02 lb/MMBtu. Other techniques for NO_x reductions are also under consideration, such as using nitrogen gas as a diluent in the combustion gas turbine to adjust the firing temperature and thereby minimize the thermal formation of NO_x.

At the present time, the conceptual design includes the use of one carbon bed filter to capture Hg from cooled syngas in or near the acid gas removal unit (see Section 2.5.1, the subsection for "Syngas Conditioning"). A single filter is expected to achieve 90 to 95 percent capture efficiency. FutureGen is expected to serve as a test bed for future Hg removal technologies.

Because FutureGen would be designed to gasify a variety of coal types (including some high sulfur coals), the plant may not be optimized to a single fuel type for either efficiency in energy conversion or pollutant minimization, so the optimal minimization of NO_x and other pollutant emissions may not be achieved. Furthermore, because the plant would be designed to accommodate a variety of R&D applications that may be proposed in the future, plant components would be integrated loosely such that the power plant as a whole may not perform optimally from an energy conversion perspective.

2.5.6.2 Solid Waste

The primary solid waste stream produced by the power plant would be slag and ash. It is estimated that 96,865 tons (87,874 metric tons) and 47,565 tons (43,150 metric tons) of slag and ash would be generated each year, respectfully. If technology Case 3B is not implemented, only slag would be generated (96,865 tons [87,874 metric tons]). If a beneficial reuse could not be found for the slag or ash, it could be disposed of on the power plant site in accordance with state regulations. The ZLD would also generate solids on the order of 5,558 tons (5,042 metric tons) per year and sludge at a rate of up to 1,545 tons (1,402 metric tons) of solid waste per year. The sludge and ZLD solids could be disposed of at a sanitary landfill if they do not exhibit hazardous waste characteristics. Elemental sulfur would be disposed of as a waste if there were no market. Carbon filters for Hg removal would probably be returned to the vendor for reactivation or recycling. The power plant would also generate regular trash (non-hazardous solid waste) that would be sent to a sanitary (municipal) landfill. As a BMP, the Alliance would institute a comprehensive pollution prevention and recycling program to minimize waste.

2.5.6.3 Marketable Products

As previously stated, the FutureGen Project would produce salable quantities of elemental sulfur or sulfuric acid. Most of the sulfur or sulfuric acid sold in the U.S. is used in the manufacture of fertilizer. Sulfuric acid is also used in oil refining, wastewater processing, and chemical synthesis. The Alliance would attempt to negotiate a contract to sell its sulfur, most likely to a fertilizer manufacturer.

The FutureGen Project would also generate 96,865 tons (87,874 metric tons) of slag and 47,565 tons (43,150 metric tons) of ash per year. If economical, the slag or ash would be transported off site to a recycling facility or manufacturer that could recycle it into a beneficial product. Slag is often recycled into blasting grit or roofing material, or it can be incorporated into hot-mix asphalt (Kalyoncu, 2002). It can also be used in railroad track ballast, fertilizer, and seawalls. Ash is often included in concrete products to enhance strength and durability. It is also used in structural fills, as feed material for cement clinker, and for road base construction. The method of slag or ash disposal would depend on the site selected to host the FutureGen Project and its local or regional markets for these products. Off-site transportation of the slag or ash could be achieved by rail or truck, which would be determined after site selection based on the location of delivery points and economic factors.

Potential markets for products and likely purchasers may be identified during the best and final offers by Site Proponents or as part of the ultimate selection of the host site. Potential environmental impacts from the use or fate of these products and impacts from the transport of products away from the power plant site would be addressed by a Supplement Analysis that would be conducted after further site characterization and site-specific design work at the host site.

2.5.6.4 Toxic and Hazardous Materials

The FutureGen Project would use a variety of process chemicals, primarily used in the treatment of process water and maintenance of the cooling towers. The selective catalytic reduction process would use approximately 1,333 tons (1,209 metric tons) per year of aqueous ammonia. If the plant generates sulfur waste in the form of sulfuric acid instead of elemental sulfur, it is possible that some sulfuric acid could be recycled for use in water processing at the plant, although some pre-treatment may be required. Table 2-11 lists the estimated quantities and uses of chemicals required to operate the FutureGen Power Plant.

Table 2-11. Estimated Quantities and Uses of Chemicals for FutureGen Plant Operation

Process	Chemical Type	Estimated Annual Quantity[1] (tpy [mtpy])	Estimated Storage On Site (gallons [liters])
H_2S and CO_2 Separation (1st and 2nd Stage)	Physical Solvent	11,300 gallons (42,775 liters)	940 (3,558)
SCR for NO_x removal	Aqueous Ammonia	1,333 (1,209)	28,700 (108,641)
Cooling Tower Operation and Maintenance	Sulfuric Acid	8,685 (7,879)	94,200 (356,585)
	Antiscalant	0.47 (0.43)	8 (30.3)
	Sodium Hypochlorite	1,684 (1,527)	32,900 (124,540)
Water Make-Up Demineralizer	Sodium Bisulfite	7 (6.4)	88 (333)
	Sulfuric Acid	21 (19.1)	225 (851)
	Liquid Antiscalant and Stabilizer	17 (15.4)	281 (1,064)
Wastewater Treatment Demineralization	Sodium Bisulfite	5.0 (4.5)	67 (253.6)
	Sulfuric Acid	85 (77.1)	921 (3,486)
	Liquid Antiscalant and Stabilizer	10 (8.7)	163 (617.0)
Clarifier Water Treatment Chemicals	Lime	1,237 (1,122)	7,380 (27,936)
	Polymer	295 (268)	5,020 (19,002)

[1] Expressed in tpy (mtpy) unless otherwise indicated.
tpy = tons per year; mtpy = metric tons per year.

2.5.6.5 Pollution Prevention, Recycling, and Reuse

The FutureGen Project would be designed to minimize process-related discharges to the environment. A plan for pollution prevention and recycling would be developed during the site-specific design and permitting steps and would be put into practice after the power plant becomes operational. Table 2-12 lists some measures that may be employed as part of that plan.

Table 2-12. Possible Pollution Prevention, Recycling, and Reuse Features

Spill Control Plan	The Spill Control Plan would specify measures to take in the event of a spill, thereby protecting environmental media from the effect of accidental releases. All aboveground chemical storage tank containment areas would be lined or paved, curbed/diked, and have sufficient volume to meet regulatory requirements. A site drainage plan would also be developed to prevent routine, process-related operations from affecting the surrounding environment.
Feed Material Handling	The coal storage area may be outdoors or covered. Measures would be taken to reduce releases of coal dust and contamination of stormwater runoff.
Coal Grinding and Slurry Preparation	The coal grinding equipment would be enclosed and any vents would be routed to the tank vent auxiliary boiler. The water used to prepare the coal

Table 2-12. Possible Pollution Prevention, Recycling, and Reuse Features

	slurry would be stripped process condensate (recycled).
Gasification, High Temperature Heat Recovery, Dry Char Removal and Slag Grinding	The char produced in gasification would be removed and returned to the first stage of the gasifier (recycled). This improves the carbon conversion in the gasifier and reduces the amount of carbon contained in the gasifier slag.
Slag Handling	The slag dewatering system would generate some flash gas that contains H_2S. The flash gas would be recycled back to the gasifier via the syngas recycle compressor. Water that is entrained with the slag would be collected and sent to the sour water stripper for recycle.
Sour Water System	Sour water would be collected from slag dewatering and the low temperature heat recovery system, and the NH_3 and H_2S would be stripped out and sent to the SRU. The stripped condensate would be used to prepare coal slurry. Surplus stripped condensate would be sent to the ZLD unit.
ZLD Unit	The ZLD unit would concentrate and evaporate the process condensate. The ZLD unit would produce high purity water for reuse and a solid filter cake for disposal off site. The ZLD would concentrate and dispose of heavy metals and other constituents in the process condensate. The ZLD would also be a recycle unit because the recovered water could be reused, reducing the total plant water consumption.
Hg Removal Features	The Hg removal unit would use specially formulated activated carbon to capture trace quantities of Hg in the syngas. Hg in the sour water handling system would be captured via activated carbon filters placed upstream of potential release points.
AGR	The AGR system would remove H_2S and CO_2 from the raw syngas and produce a H_2-rich synthetic fuel (synfuel) for use in the combined cycle power system. The AGR would produce concentrated H_2S feed for the SRU and concentrated CO_2 for drying, compression, and sequestration. For co-sequestration activities, a mixed stream of H_2S and CO_2 would be compressed and dried for sequestration.
SRU	The SRU would convert the H_2S to elemental sulfur that would be marketed for use as a fertilizer additive or for production of sulfuric acid. The tail gas from the SRU would be recycled back to the gasifier.
Boiler Blowdown and Steam Condensate Recovery	Boiler blowdown and steam condensate would be recovered from the combined cycle power system and gasification facilities, and would be reused as cooling tower makeup water.
Training and Leadership	All corporate and plant personnel would be trained on continuous improvement in environmental performance, especially as such training and programs apply to 1) setting, measuring, evaluating and achieving waste reduction goals; and 2) reporting the results of such programs in annual reports made available to the public.

2.5.7 CONSTRUCTION PLANS

2.5.7.1 Construction Staging and Schedule

The FutureGen Project facilities would be constructed over the course of up to 44 months, including the installation of utility lines and connections, sequestration site wells and equipment, and supporting structures. Before construction, environmentally sensitive areas at the selected site would be identified so that impacts could be minimized. A Stormwater Pollution Prevention Plan (SWPPP) would be developed to identify BMPs for erosion prevention and sediment control during construction. The plan would include a description of construction activities and address the following:

- Potential for discharge of sediment or pollutants from the site.
- Location and type of temporary and permanent erosion prevention and sediment control BMPs, along with procedures to be used to establish additional temporary BMPs as necessary for the site conditions during construction.

- Site map with existing and final grades, including dividing lines and direction of flow for all pre- and post-construction stormwater runoff drainage areas located within the project limits. The site map must also include impervious surfaces and soil types.
- Location of areas not to be disturbed.
- Location of areas where construction would be phased to minimize duration of exposed soil.
- Identify surface waters and wetlands, either on site or within 0.5 mile (0.8 kilometer) of the site boundaries, which could be affected by stormwater runoff from the construction site during or after construction.
- Methods to be used for final stabilization of all exposed soil areas.

Initial site preparation activities may include, depending on the site selected, building access roads, clearing brush and trees, leveling and grading the site, connecting to utilities, and dewatering activities. Construction of temporary parking, offices, and material storage areas would involve the use of large earthmoving machines to clear and prepare the site. Trucks would bring fill material for roadways and the power plant site, remove harvested timber, remove debris from the site, and temporarily stockpile materials. Construction crews would spread gravel and road base for the temporary roads, material storage areas, and parking areas.

During construction, worker vehicles, heavy construction vehicles, diesel generators, and other machinery and tools would generate emissions. Fugitive dust would result from excavation, soil storage, and earthwork. Construction-related emissions and noise would be minimized by running electricity to the site from the local utility provider to reduce reliance on diesel generators and by wetting soil to reduce dust during earthwork.

2.5.7.2 Construction Materials and Suppliers

Construction material would be delivered to the site by truck and rail. An access road to the power plant site would be developed for construction traffic and completion of the rail spur at the start of construction activities would allow some plant equipment to be delivered by rail. An estimated 20 trucks, and approximately two trains per week would deliver material to the site on a daily basis.

During construction, temporary utilities would be extended to construction offices, worker trailers, lay down areas, and construction areas. The local electricity service would provide temporary construction power. Temporary generators could also be used until the temporary power system would be completed. Construction crews would position temporary lighting for safety and security. Local telecommunication lines would be installed for phone and electronic communications.

Water would be required during construction for various purposes, including personal consumption and sanitation, concrete formulation, preparation of other mixtures needed to construct the facilities, equipment washdown, general cleaning, dust suppression, and fire protection (DOE, 2007).

2.5.7.3 Construction Labor

Based on other coal-fueled power plant construction projects, it is estimated that an average of 350 construction workers would be employed throughout the project; however, during peak construction the projected number of employees could be as many as 600 to 700 workers on site (DOE, 2007). The Alliance expects that labor would be supplied through the local building trades. It is estimated that construction workers would work a 50-hour work week and that construction activity would not always be restricted to daytime hours.

2.5.7.4 Construction Safety Policies and Programs

Emergency services during construction would be coordinated with the local fire departments, police departments, paramedics, and hospitals. A first-aid office would be located on site for minor first-aid incidents. Trained and certified health, safety, and environmental personnel would be on site to respond to and coordinate emergency response. All temporary facilities would have fire extinguishers, and fire protection would be provided in work areas where welding work would be performed.

The natural gas and CO_2 pipeline facilities would be designed, constructed, tested, and operated in accordance with applicable requirements included in the Department of Transportation regulations in 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, and other applicable federal and state regulations, including U.S. Department of Labor Occupational Safety and Health Administration requirements. These regulations provide for adequate protection for the public and workers and prevention of natural gas pipeline accidents and failures. Among other design standards, 49 CFR Part 192 specifies pipeline materials and qualifications, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

2.5.7.5 Construction Waste

Construction of the FutureGen Project would generate certain amounts of waste. The predominant waste streams during construction would include vegetation, soils, and debris from site clearing; scrap metal; hydrostatic pressure test (hydrotest) water; used oil; surplus materials; pallets and other packaging materials; and empty containers.

Surplus and waste materials would be recycled or reused to the extent practical. If feasible, removed site vegetation would be salvaged for pulp and paper production, or recycled for mulch. Construction water use would be heaviest during the CO_2 pipeline testing phase. Hydrotest water would be reused for subsequent pressure tests if practical. Spent hydrotest water would be tested to determine if it exhibits hazardous characteristics (e.g., traces of pipe oil or grease). If hazardous, the hydrotest water would be sent off site for treatment; if non-hazardous, it would be routed to the detention basin for discharge to local surface waters (in accordance with the National Pollutant Discharge Elimination System [NPDES] permit). Potential scrap and surplus materials, and used lubricant oils would be recycled or reused to the maximum extent practical.

The Alliance would ultimately be responsible for the proper handling and disposal of construction waste. However, construction management, contractors, and their employees would be responsible for minimizing the amount of waste produced by construction activities. They would also be expected to adhere to all project procedures and regulatory requirements for waste minimization and proper handling, storage, and disposal of hazardous and non-hazardous waste. Each construction contractor would be required to include waste management in their overall project health, safety, and environmental site plans. Typical construction waste management activities may include:

- Dedicated areas and a system for waste management and segregation of incompatible waste. Waste segregation should occur at time of generation.
- A waste control plan detailing waste collection and removal from the site. The plan would identify where waste of different categories would be collected in separate stockpiles, bins, etc. and clear, appropriate signage would be required to identify the category of each collection stockpile, bin, etc.
- Storage of hazardous waste, as defined by the applicable regulations, separately from non-hazardous waste (and other, non-compatible hazardous waste) in accordance with applicable regulations, project-specific requirements, and good waste management practices.

- Periodic inspections to verify that waste are properly stored and covered to prevent accidental spills and to prevent waste from being blown away.
- Appropriately labeled waste disposal containers.
- Good housekeeping procedures. Work areas would be left in a clean and orderly condition at the end of each working day, with surplus materials and waste transferred to the waste management area.

2.5.8 OPERATION PLANS

As stated in Section 2.2, DOE-sponsored activities under the FutureGen Project would include 1 year of startup (scheduled to begin in 2012); 3 years of plant operation, testing, and research; followed by 2 years of additional geologic monitoring of the sequestered CO_2. Section 2.2 describes expected research activities. However, it is generally expected that the plant would continue to operate for at least 20 to 30 years and possibly up to 50 years. After the DOE-sponsored research activities conclude, the Alliance and DOE would develop a disposition plan that addresses the future management and operation of the power plant.

2.5.8.1 Operational Labor

Operator hiring and training would begin about 1 year before the commencement of startup. Gasification area personnel would need extensive training in plant operations, reactive chemicals, and safety, industrial hygiene, and environmental compliance similar to that of operators in refineries and chemical plants. Process simulators would be used as part of the training program. Generally, the staff would consist of management and engineers, shift supervision and operations management, and shift operating personnel. The operations staff would be integrated into the commissioning team so that they would have hands-on experience with the power plant when each system becomes operational after construction.

In addition to operations and management personnel, the FutureGen Project would require qualified staffing in the following areas: power production planning; equipment maintenance; procurement; research and development; health, safety, and environmental protection; administrative support; benefits/human relations; and other necessary functions. The Alliance estimates that the plant would employ approximately 200 full-time workers (FG Alliance, 2006g).

2.5.8.2 Health and Safety Policies and Programs

Facility design features and management programs would be established to address hazardous materials storage locations, emergency response procedures, employee training requirements, hazard recognition, fire control procedures, hazard communications training, personal protective equipment training, and reporting requirements. For accidental releases, significance criteria would be determined based on federal, state, and local guidelines, and on performance standards and thresholds adopted by responsible agencies.

Basic approaches to prevent spills to the environment include comprehensive containment and worker safety programs. The comprehensive containment program would ensure the use of appropriate tanks and containers, as well as proper secondary containment using walls, dikes, berms, curbs, etc. Worker safety programs would ensure that workers are aware of, and trained in, spill containment procedures and related health, safety and environmental protection policies.

2.5.9 POST-OPERATION ACTIVITIES

2.5.9.1 Post-Injection Monitoring

One goal of the FutureGen Project is to prove the safe and effective storage of CO_2 in a deep saline formation. At a minimum, post-injection monitoring activities would be conducted in accordance with applicable UIC regulations and permit conditions. The UIC program is evolving to specifically address geologic sequestration and its long-term safety. At this time, it is difficult to precisely predict the types and frequency of post-operational monitoring and testing that may be required under the UIC program.

However, it is likely that seismic and atmospheric monitoring surveys would occur periodically after closure of the injection site. Some subset of monitoring equipment and structures installed during the period of injection may be kept in place to assess long-term, post-closure changes in surface deformation, soil gas, or atmospheric fluxes in CO_2 (FG Alliance, 2006g).

Both the Alliance and DOE acknowledge the need for continued monitoring of the sequestered CO_2 during the period of continued plume expansion or migration following cessation of injection. During the co-funded period of the project, the Alliance would apply a variety of monitoring techniques in an effort to identify those that provide the most useful and practical means of determining movement of CO_2 and storage integrity of the formation of the CO_2.

As part of the Full Scope Cooperative Agreement activities, DOE and the Alliance will develop a plan for continued monitoring of the sequestered CO_2 after completion of the project.

2.5.9.2 Final Closure Phase Provisions

The planned life of the FutureGen Project would be 20 to 30 years. However, if the facility is still economically viable, it could be operated up to 50 years. A closure plan would be developed at the time that the power plant was to be permanently closed. The removal of the facility from service, or decommissioning, may range from “mothballing” to the removal of all equipment and facilities, depending on conditions at the time. The closure plan would be provided to state and local authorities as required.

Upon completion of CO_2 injection, all surface facilities would be decommissioned, including connections between the power plant and injection wells. All exposed pipes, along with other surface facilities, would be decommissioned and removed during site closure. All wells drilled for injection or monitoring, and that intercept the target formation, would be plugged and abandoned in accordance with state and federal regulations. However, some monitoring wells could remain in place, to monitor the long-term integrity of the caprock and to test for potential leakage into aquifers above the CO_2 reservoir.

2.6 FUTURE ACTIVITIES

2.6.1 FOLLOW-ON DECISIONS AND PLANNING

No sooner than 30 days after EPA publishes a Notice of Availability (NOA) of the Final EIS, DOE will publish a Record of Decision (ROD) in the *Federal Register* that explains the agency’s decision on whether to fund the FutureGen Project and, if so, which of the alternative sites, if any, would be acceptable to host the FutureGen Project.

2.6.1.1 Design Development and Refinement

The design of the power plant and CO_2 injection process would continue to be refined until commencement of construction. Some of the assumptions made in this EIS may be modified as the design progresses. The site selected for the project would primarily affect the design elements related to supporting utilities and transportation systems. Additional utility interconnection studies of road and rail designs may be conducted.

2.6.1.2 Additional Site Characterization Activities

At the selected site, the Alliance would undertake more detailed site-characterization, which would support site-specific design work. For the power plant site, these activities could include detailed surveys and elevation measurements, soil tests to support foundation design, biological surveys if warranted, and local traffic studies. For the sequestration site, these activities could include installation of exploratory wells, seismic imaging of the target reservoir, small-scale injection tests, and additional computer simulation and modeling of plume fate and transport.

Additional site-specific information would be needed to better determine the injectivity and storage capacity of the target reservoirs as well as the integrity of the caprock. The Alliance would gather this information by drilling one or more exploratory wells into the target formation and undertaking various tests and sampling. While drilling, core samples would be taken from the target formation, the primary seal and portions of the overlying zones to determine the bulk permeability and other geologic characteristics of the rock. Well testing could include pressure and temperature readings or fluid testing as described in Section 2.5.2.2.

Well drilling activities would include the creation of a temporary or permanent access road (paved or unpaved) to the well site and installing a temporary catch basin to store produced saline water and drill cuttings. Because these wells would be thousands of feet deep, a single well could require 3 to 5 weeks of drilling depending on the well depth, diameter and formation properties.

The Alliance may also conduct seismic surveys (see Section 2.5.2.2) which are generally conducted over a very large area (larger than the predicted plume radius). The Alliance would secure permission prior to conducting these surveys from affected land owners to gain access, run geophone lines and possibly dig shot-holes. While these surveys use either very small amounts of explosives or heavy steel vibrators to produce sound waves that would be reflected by the subsurface rock layers to varying degrees, vibrations are rarely felt at the surface because the energy levels are small.

2.6.1.3 Future NEPA Activities

Based on the results of the additional site-characterization and site-specific preliminary design, DOE will complete a Supplement Analysis to determine whether a Supplemental EIS must be prepared. A Supplemental EIS would be required if there are substantial changes to the Proposed Action or significant new circumstances or information relevant to environmental concerns. If DOE completes a Supplement Analysis or Supplemental EIS, DOE would determine whether to revise ***the*** ROD.