CHRISTIAN COUNTY GENERATION, L.L.C.

1044 N. 115 Street, Suite 400
Omaha, Nebraska 68154-4446
402-691-9500
FAX: 402-691-9530

September 20, 2011

Mr. Jeffrey R. McDonald
U.S. Environmental Protection Agency Region 5
Water Division
77 W. Jackson Blvd.
Chicago, IL 60604-3590

RE: Christian County Generation, LLC- Taylorville, Illinois
Class VI Permit Request

Dear Mr. McDonald:

Pursuant to the regulations that pertain to the Underground Injection Control program under the EPA, Christian County Generation, LLC is submitting a request for two Class VI injection wells (TEC #1 and TEC #3) under 40 CFR Part 146. The wells will be used to inject carbon dioxide from the Christian County Generation Station.

Enclosed is one (1) electronic copy on CD and one (1) hard copy of the Class VI UIC Permit Application for the Taylorville Energy Center. The application is based on work completed for the Class I Non-Hazardous Waste UIC Permit Application submitted to Illinois EPA in December, 2009. The Class VI application has been updated with a new Area of Review (AOR) determination using a four-well injection scenario. The format for the enclosed application is based on the new Class VI regulations and available draft guidance documents from US EPA.

Please let us now as soon as possible if you need any additional information or documentation for the application. If you have any questions, please do not hesitate to contact Mr. Ryan Choquette, Manager Midstream Engineering, at 402-938-1641 or rchoquette@tenaska.com

We appreciate your prompt attention and look forward to development of this first-ever full-scale commercial CO_2 storage project.

CHRISTIAN COUNTY GENERATION, L.L.C.
By: Tenaska Taylorville, LLC, as Managing Member
By: Tenaska, Inc., its Manager

By: Ryan Choquette For Greg Kunkel
Greg Kunkel, Ph.D.
Vice President of Environmental Affairs

Acknowledged by Janice I. Springer

GENERAL NOTARY - State of Nebraska
JANICE I. SPRINGER
My Comm. Exp. June 30, 2014

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency

Underground Injection Control Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number

	T/A	C
U		

Read Attached Instructions Before Starting

For Official Use Only

Application approved (mo day year)	Date received (mo day year)	Permit Number	Well ID	FINDS Number

II. Owner Name and Address

Owner Name: Christian County Generation, L.L.C.

Street Address: 1044 N. 115 St, Suite 400 | Phone Number: (402) 938-1641

City: Omaha | State: NE | ZIP CODE: 68154-4446

III. Operator Name and Address

Owner Name: Christian County Generation, L.L.C.

Street Address: 1044 N. 115 St, Suite 400 | Phone Number: (402) 938-1641

City: Omaha | State: NE | ZIP CODE: 68154-4446

IV. Commercial Facility	V. Ownership	VI. Legal Contact	VII. SIC Codes
[x] Yes [ ] No	[x] Private [ ] Federal [ ] Other	[x] Owner [ ] Operator	4911

VIII. Well Status *(Mark "x")*

[ ] A. Operating — Date Started (mo day year):

[ ] B. Modification/Conversion

[x] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

[x] A. Individual [ ] B. Area	Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
	0	2	Taylorville Energy Center

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
Class VI	Other (CO2)	Wells are for storage of caron dioxide. Proposed storage reservoir is the Mt. Simon sandstone	

XI. Location of Well(s) or Approximate Center of Field or Project

Latitude Deg	Latitude Min	Latitude Sec	Longitude Deg	Longitude Min	Longitude Sec	Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
39	35	46.9	89	16	10.5	12	13N	2W	NW				

XII. Indian Lands (Mark 'x')

[ ] Yes
[x] No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibliity of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*: Greg Kunkel, Vice-President (signed by Ryan Choquette for Greg Kunkel)

B. Phone No. *(Area Code and No.)*: (402) 691-9506

C. Signature: Ryan Choquette

D. Date Signed: 9-20-11

EPA Form 7520-6 (Rev. 12-08)

GENERAL NOTARY - State of Nebraska
JANICE I. SPRINGER
My Comm. Exp. June 30, 2014

Janice I. Springer
(witnessed Ryan Choquette's Signature as being said person.)

Well Class and Type Codes

Class I		Wells used to inject waste below the deepest underground source of drinking water.
Type	**"I"**	Nonhazardous industrial disposal well
	"M"	Nonhazardous municipal disposal well
	"W"	Hazardous waste disposal well injecting below USDWs
	"X"	Other Class I wells (not included in Type "I," "M," or "W")
Class II		Oil and gas production and storage related injection wells.
Type	**"D"**	Produced fluid disposal well
	"R"	Enhanced recovery well
	"H"	Hydrocarbon storage well (excluding natural gas)
	"X"	Other Class II wells (not included in Type "D," "R," or "H")
Class III		Special process injection wells.
Type	**"G"**	Solution mining well
	"S"	Sulfur mining well by Frasch process
	"U"	Uranium mining well (excluding solution mining of conventional mines)
	"X"	Other Class III wells (not included in Type "G," "S," or "U")

Other Classes Wells not included in classes above.
Class V wells which may be permitted under §144.12.
Wells not currently classified as Class I, II, III, or V.

Attachments to Permit Application

Class	**Attachments**
I new well	A, B, C, D, F, H – S, U
existing	A, B, C, D, F, H – U
II new well	A, B, C, E, G, H, M, Q, R; optional – I, J, K, O, P, U
existing	A, E, G, H, M, Q, R, – U; optional – J, K, O, P, Q
III new well	A, B, C, D, F, H, I, J, K, M – S, U
existing	A, B, C, D, F, H, J, K, M – U
Other Classes	To be specified by the permitting authority

INSTRUCTIONS - Underground Injection Control (UIC) Permit Application

Paperwork Reduction Act: The public reporting and record keeping burden for this collection of information is estimated to average 224 hours for a Class I hazardous well application, 110 hours for a Class I non-hazardous well application, 67 hours for a Class II well application, and 132 hours for a Class III well application. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, DC 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

This form must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for permit by the Director.

I. **EPA I.D. NUMBER** - Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. **OWNER NAME AND ADDRESS** - Name of well, well field or company and address.

III. **OPERATOR NAME AND ADDRESS** - Name and address of operator of well or well field.

IV. **COMMERCIAL FACILITY** - Mark the appropriate box to indicate the type of facility.

V. **OWNERSHIP** - Mark the appropriate box to indicate the type of ownership.

VI. **LEGAL CONTACT** - Mark the appropriate box.

VII. **SIC CODES** - List at least one and no more than four Standard Industrial Classification (SIC) Codes that best describe the nature of the business in order of priority.

VIII. **WELL STATUS** - Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if wells(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

IX. **TYPE OF PERMIT** - Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field," submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

X. **CLASS AND TYPE OF WELL** - Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of the application. When selecting type X please explain in the space provided.

XI. **LOCATION OF WELL** - Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR Part 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

XII. **INDIAN LANDS** - Place an "X" in the box if any part of the facility is located on Indian lands.

XIII. **ATTACHMENTS** - Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, III are described on pages 4 and 5 of this document and listed by Class on page 2. Place EPA ID number in the upper right hand corner of each page of the Attachments.

XIV. **CERTIFICATION** - All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

INSTRUCTIONS - Attachments

Attachments to be submitted with permit application for Class I, II, III and other wells.

A. **AREA OF REVIEW METHODS** - Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.

B. **MAPS OF WELL/AREA AND AREA OF REVIEW** - Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I

The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map;

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. This requirement does not apply to existing Class II wells;

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. **CORRECTIVE ACTION PLAN AND WELL DATA** - Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

Class I

A description of each well's types, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include the corrective action proposed to be taken by the applicant under 40 CFR 144.55.

Class II

In addition to requirement for Class I, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. **MAPS AND CROSS SECTION OF USDWs** - Submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. **NAME AND DEPTH OF USDWs (CLASS II)** - For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. **MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA** - Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

G. **GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (Class II)** - For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. **OPERATING DATA** - Submit the following proposed operating data for each well (including all those to be covered by area permits): (1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure; (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. **FORMATION TESTING PROGRAM** - Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the testing must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the program formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. **STIMULATION PROGRAM** - Outline any proposed stimulation program.

K. **INJECTION PROCEDURES** - Describe the proposed injection procedures including pump, surge, tank, etc.

L. **CONSTRUCTION PROCEDURES** - Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to packer for Class I.)

M. **CONSTRUCTION DETAILS** - Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. **CHANGES IN INJECTED FLUID** - Discuss expected changes in pressure, native fluid displacement, and direction of movement of injection fluid. (Class III wells only.)

O. **PLANS FOR WELL FAILURES** - Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or wells failures, so as to prevent migration of fluids into any USDW.

P. **MONITORING PROGRAM** - Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Q. **PLUGGING AND ABANDONMENT PLAN** - Submit a plan for plugging and abandonment of the well including: (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used; (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.

R. **NECESSARY RESOURCES** - Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available.

S. **AQUIFER EXEMPTIONS** - If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon production, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR Sections 144.7 and 146.04.

T. **EXISTING EPA PERMITS** - List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc.

U. **DESCRIPTION OF BUSINESS** - Give a brief description of the nature of the business.

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Taylorville Energy Center 1630 N 1400 E Rd, Taylorville, IL 62568	Christian County Generation, L.L.C. 1044 N 115 St., Suite 400, Omaha, NE 68154-4446

Locate Well and Outline Unit on Section Plat - 640 Acres

N

X

W E

S

State	County	Permit Number
Illinois	Christian	

Surface Location Description

1/4 of nw 1/4 of nw 1/4 of nw 1/4 of Section 12 Township 13n Range 2w

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 2

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Lease Name

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
20 in	94	400	397	26 inch
13 3/8	61 or 68	5400	5397	17 1/2
9 5/8	40 or 47	6500	6497	12 1/4

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	12 1/4	9 5/8	9 5/8	9 5/8			
Depth to Bottom of Tubing or Drill Pipe (ft	6500	6500	6500	6500			
Sacks of Cement To Be Used (each plug)	275	180	180	etc to sfc			
Slurry Volume To Be Pumped (cu. ft.)	491	251	251	251			
Calculated Top of Plug (ft.)	6500	6000	5500	etc to sfc			
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.8	15.8	15.8	15.8			
Type Cement or Other Material (Class III)	Class H	Class H	Class H	Clas H			

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
12 1/4-inch open hole 7200	6500		
Perforations TBD 9 5/8 casing	5800 to 6400		

Estimated Cost to Plug Wells

Estimated at $379,000 per well

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibliity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Greg Kunkel, Vice President	Ryan Choquette For Greg Kunkel	9/20/2011

GENERAL NOTARY - State of Nebraska
JANICE I. SPRINGER
My Comm. Exp. June 30, 2014

(witnessed Ryan Choquette's Signature as being said person.)

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 4.5 hours for operators of Class I hazardous wells, 1.5 hours for operators of Class I non-hazardous wells, 3 hours for operators of Class II wells, and 1.5 hours for operators of Class III wells.
Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.
Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

Christian County Generation, L.L.C.
IEPA Class VI UIC Application

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Appendix 2-1	USGS and NEIC Earthquake and Seismic Data, Illinois Earthquakes, NEIC Historical Earthquake Catalogs/Maps
Appendix 2-2	Well Plugging Records and Affidavits (Illinois Department of Mines and Minerals—Oil and Gas Division
Appendix 2-2A	Three Deepest Drilled Wells Well Plugging Records and Affidavits (Illinois Department of Mines and Minerals—Oil and Gas Division
Appendix 2-2A-1	Artificial Penetration Well Schematic of Deepest Wells
Appendix 2-2B	Three Saltwater Disposal Wells Well Plugging Records and Affidavits (Illinois Department of Mines and Minerals—Oil and Gas Division
Appendix 2-2B-1	Artificial Penetration Well Schematic of Salt Water Disposal Wells

GENERAL INFORMATION

Operator

Christian County Generation, L.L.C. is submitting the following geologic studies, injection well design, and other planning documents in support of the Taylorville Energy Center UIC project US EPA Class VI Permit application.

The principal contact for Christian County Generation, L.L.C. is:

Christian County Generation, L.L.C.
Ryan Choquette, Manager, Midstream Engineering Tenaska, Inc. 1044 N. 115 Street Suite 400 Omaha, NE 68154-4446 Tel: 402-938-1641 rchoquette@tenaska.com www.tenaska.com

The Taylorville Energy Center (TEC) project is to be permitted and constructed by Christian County Generation, L.L.C.

Drilling and Reporting

After final approval by US EPA of the Class VI Permit Application, TEC will be authorized to commence drilling and installation of the first injection well. Since the ultimate design of this well is subject to both an US EPA technical review and public review process, an update of the engineered well design and construction plan is envisioned to incorporate findings of modeling and engineering assessments, based upon the additional data and information produced from the drilling program.

Core analysis, acquisition and analysis of well logs, and interpretation of all available geologic and reservoir data will follow completion of drilling. A revised Area of Review (AOR) and Corrective Action Plan will be submitted to US EPA. The revised plan, potentially with suggested Permit amendments, will incorporate information obtained from analysis of the first well in the permit administrative record (i.e. TEC #1).

A package of technical and well data acquired from the TEC #1-injection well also will be prepared and submitted to US EPA. Following this submittal, and final approval by US EPA, TEC would be authorized to perform final well completion and Mechanical Integrity Testing (MIT) on TEC #1-injection well. TEC #2, TEC #3, and if needed, TEC #4 injection wells will be drilled and completed with final MITs and all completion reports submitted to US EPA.

Note that at present, only the first three injection wells are planned. Property has been optioned for TEC #1 at the plant site and TEC #3 four miles north of the plant site. Additional agreements for TEC #2, and TEC #3 4 will be executed contingent on final permitting, approval, funding for the TEC project and results for TEC 1. If, based on site specific data and final TEC operating criteria, a fourth injection well is needed, then TEC #4 would be installed. The AOR for the project is based on a four-well scenario. However, the base case modeling and injection system design is based on a three-well scenario.

Prior to injection, other plans will be updated as needed, and submitted to US EPA for review and approval. These plans include:

- Area of Review and Corrective Action Plan
- Testing and Monitoring Plan
- Emergency and Remedial Response Plan
- Injection Well Plugging Plan
- Post-Injection Site Care (PISC) and Site Closure Plan

Christian County Generation, L.L.C.
US EPA Class VI UIC Application

TECHNICAL REPORT

1.0 ADMINISTRATIVE INFORMATION

The following Permit Application, Technical Report, and project plans have been compiled in support of the Christian County Generation, L.L.C. US EPA Class VI UIC Permit application for the Taylorville Energy Center (TEC).

1.1 Project Background

Christian County Generation, L.L.C. was formed for purposes of developing the TEC in south-central Illinois. The proposed electric generating facility is a 730-megawatt (gross) plant using advanced Integrated Gasification Combined-Cycle (IGCC) technology, which offers very low emissions of criteria pollutants as well as, in this case, carbon capture and sequestration (CCS) capability.

This technology is groundbreaking and environmentally advanced for coal power plants that generate electricity, while dramatically lowering emissions and capturing and permanently storing at least 50 percent of the greenhouse gas carbon dioxide (CO_2) that would otherwise enter the atmosphere.

Christian County Generation, L.L.C. is the first of its kind facility proposed for Illinois, and one of the first in the nation. It is designed to be one of the most environmentally responsible power plants in the world that uses coal within IGCC technology. The plant will capture at least 50% of the greenhouse gas CO_2 and create a new market for Illinois coal industry while providing economic development and benefits for areas of the state requiring industrial base. Additionally, it will increase protection of the environment and public health, while saving millions of dollars annually on power costs for Illinois consumers.

The Illinois General Assembly passed Senate Bill 1987 (SB 1987), the Clean Coal Portfolio Standard Act to encourage development of environmentally advanced electric generation plants. SB 1987 requires large utilities to enter into long-term, cost-based contracts to purchase up to 5 percent of their electricity from clean coal facilities that capture at least 50 percent of their greenhouse gas emissions. This cost-based approach was originally proposed by Illinois Attorney General Lisa

Madigan, and was developed jointly with the Citizens Utility Board of Illinois, and is specifically designed to protect consumers.

Further details on the TEC can be found on the following web sites: www.tenaska.com; www.cleancoalillinois.com and in Appendix 1-1.

1.2 Taylorville IGCC Facility

The TEC being developed by Christian County Generation, L.L.C. is a proposed IGCC plant where coal is converted to a synthetic gas and then substitute natural gas, which can either be used to produce electricity or sold into the natural gas pipeline. Pollutants can be segregated and captured prior to combustion, making IGCC plants significantly cleaner than conventional coal generating facilities. This project will also pioneer a technology essential in the global effort to reduce greenhouse gases – the ability to capture and remove most of process generated carbon dioxide prior to combustion, thereby offering lesser facility emissions.

A Class VI well permit application and technical report is submitted by TEC to manage the CO_2 stream.

The plant's coal gasification technology will dramatically reduce air emissions, allowing Illinois coal, which has high-sulfur content, to become a more environmentally sound fuel source for the region.

One initial injection well is planned to be drilled by mid-2012 for purposes of collecting geologic data and reservoir information, with up to three additional injection wells covered in the permit request for this facility. The objective is to drill a well through the Mount Simon Sandstone to near Pre-Cambrian basement (~7,200 feet) and evaluate the lowermost geologic formations suitable for supercritical CO_2 injection and storage. The goals of this project are to:

(1) Collect geologic and geophysical data in the well (cores, logs), and

(2) Conduct tests of formation salinity, fluid recoveries in multiple favorable intervals potentially suitable for injection.

(3) Acquire subsurface reservoir information and site specific data for inclusion into an updated Class VI permit request, including updated modeling and AOR to US EPA.

(4) Have an operational CO_2 injection well

Potential favorable injection intervals are located within the Cambrian aged Mount Simon Sandstone.

1.3 Applicant/Operator Information

The operator of the injection wells will be the Christian County Generation, L.L.C. (CCG), the developer of the IGCC electric power generating facility. Contact information for CCG and this permit application and project is as follows:

Mr. Ryan Choquette, Manager, Midstream Engineering
Christian County Generation, L.L.C.
1044 N. 115 Street
Suite 400
Omaha, NE 68154-4446
TEL: (402) 938-1641
FAX: (402) 691-9530
rchoquette@tenaska.com

1.4 Well Location

The initial injection well will be used as a stratigraphic test well to gather suitable site-specific information on the geology and reservoir potential of the Mount Simon Sandstone injection interval, and the sealing capability of the overlying Eau Claire Shale confining interval.

Up to three additional Class VI injection wells (TEC #2, #3, and #4-injection wells) may be developed for the completed site, but are totally dependent on the specific CO_2 storage capability of the Mount Simon Sandstone injection horizon in this area. The location of the injection well field is situated in central Christian County, Illinois (Figure 1-1), as defined on the Taylorville and Willeys 7.5 minute USGS topographic quadrangle map (Figure 1-2). A detailed aerial photograph (Figure 1-3) and topographic map (Figure 1-4) provide the approximate well location for the initial well. The location of the first well (TEC #1) has been determined as NW 1/4 of NW1/4 of NW1/4 of Section 12, T13N R2W, Christian County, Illinois. The additional well locations have not been finalized. The number, name, and location of each injection well will be included in a construction report for each well. The approximate TEC #1-injection well is located as follows:

Latitude (NAD83) 39º 35’ 46.96”
Longitude (NAD83) 89º 16’ 10.56”
Section 12 Township 13 North Range 2 West
Section 7 Township 13 North Range 1 West

Elevation 615 feet

The proposed additional wells (TEC #2, #3, and #4-injection wells (Figures 1-3, 1-4)) would be developed as needed. Final well locations would be based on the identified site geologic conditions as obtained from the initial TEC #1-injection well drilling and geologic data. Expectations are that an update of the geology, the injection flow modeling and reservoir simulation results would be provided to US EPA post-drilling of the TEC #1-injection well.

The proposed land area for the TEC IGCC facility includes the location of the proposed injection wells, which are situated on predominantly agricultural property in rural Christian County, whose primary land use is for agriculture consisting of row crops and pasture land (Figures 1-5 and 1-6).

1.5 Surface Land Access and Ownership

The surface land has been optioned in Section 12 T 13 N R 2 W and Section 7 T 13 N R 1 W for purposes of drilling the initial TEC #1-injection well and obtaining geologic, reservoir and hydrologic information. As well as a parcel of land located in the Southwest Quarter of Section 13 of Township 14 North Range 2 West for TEC 3. CCG may acquire the additional land parcel areas for the injection wells, and proceed with plant construction.

1.6 Operator Financial Assurance

Since CCG intends to project finance the TEC, there are unique considerations present with respect to meeting financial assurance obligations. CCG will provide financial assurance in the form of a letter of credit, cash deposit, bond or corporate guarantee from a creditworthy entity to secure its obligations in connection with the Injection Wells. This instrument will be effective at or prior to commencement of drilling of the first Injection Well. A follow-up letter of credit, cash deposit, bond or guarantee from a creditworthy entity will be placed by CCG at or before the commencement of drilling of each subsequent injection well. The proposed documentation for financial assurance will be provided to US EPA prior to commencement of drilling of each respective injection well. A retirement reserve will be funded from project cash flow over time, and each funding will go to reduce CCG's financial assurance instrument obligation dollar-for-dollar. The accrued sum of the retirement reserve balance plus the financial assurance instrument will equal the amount of the required security necessary for the injection wells. A demonstration of financial assurance via a verification letter to US EPA for this Class VI Permit Application will be submitted at the time of the respective security issuances.

1.7 Regulatory Unit Designations & List of Formations

The following regulatory unit designations and the list of depths and formations are compiled in the table below and apply toward US EPA UIC Permit Conditions for the proposed TEC injection wells. Appendix 1-2 contains an annotated type log with all pertinent formations and key regulatory units, formations, and estimated depths labeled.

Unit	Estimated Depth (feet)
Lowermost USDW	250
Secondary Confining Unit (New Albany Shale)	1800
Secondary Confining Unit (Maquoketa Shale)	2500
St. Peter Sandstone	3100
Primary Upper Confining Unit (Eau Claire Shale)	5000
Mount Simon Sandstone Injection Interval	**5615**
TD – Total Depth	7200
Lower Confining Unit (Basement Granite)	~7200

1.8 Public Outreach

TEC personnel firmly believe that public outreach efforts with the local county and community officials and the public are very important criteria for successful development and operation of the proposed IGCC facility. Periodic meetings and updated information from TEC will be held to inform the local community and public on the progress of project construction and operation. A series of initial public meetings in Christian County presented facility plans and goals to county authorities, government and local residents. A public outreach program has been underway, with submittal of Air Permit requirements, and the National Environmental Policy Act (NEPA) process. Additional area and community meetings are planned before drilling of the initial well begins, and after final construction and completion of the facility.

1.9 Project Impacts

Within this permit, TEC has identified and evaluated impacts to the local community, potential oil and gas resources, current and future water resources, and present day land usage as part of the application process. The proposed three (potentially four) injection wells will occupy a limited surface land footprint, and will be constructed according to stringent Class VI well construction standards.

Engineering best practices will be followed using stringent Class VI injection well regulations for protection of freshwater and oil and gas resources in the area.

A rigorous surface monitoring program (see Testing and Monitoring Plan) has been designed and will be implemented to protect all shallow drinking water horizons, the lowermost Underground Source of Drinking Water (USDW).

1.10 Preliminary Area of Review

A preliminary area of review was developed for the project and is discussed in detail in the Area of Review and Corrective Action Plan. The base case modeling assumed that three injection wells would be required for the Taylorville site. Additional modeling was completed that assumes four injection wells will be constructed. The four-well case was developed to address several issues noted in the modeling including the need to reduce injection bottom hole pressures during the initial system start up and to provide some operational flexibility for the system.

The AOR is based on a pressure front differential of approximately 180 psi and is shown in Figure 1-7 based on thirty years of injection. The pressure differential was calculated using the Maximum Extent of the Separate-phase Plume or Pressure-front (MESPOP) approach outlined in the draft Area of Review Evaluation and Corrective Action guidance document.

2.0 GEOLOGY

This section contains an evaluation and review of the regional, local, subsurface and surface geology present at the proposed TEC site. Although there is no site specific deep geologic information present from drilled wells into the Mount Simon Sandstone in the Christian County area, sufficient subsurface data was obtained from the 2D seismic survey performed at the Taylorville site, and from regional offset wells.

The specific focus of this evaluation is directly on the geologic and reservoir suitability of the injection and containment formations and identifying the suitability of the subsurface geology with an interpretation of overlying formations.

2.1 Introduction

The geologic suitability of a specific stratigraphic interval for injection and long-term confinement of CO_2 is determined primarily by the following criteria:

- Lateral extent, thickness, porosity, and permeability of the injection reservoir;
- Lateral extent, thickness, porosity, and permeability of the overlying confining zone;
- Hydrogeologic compatibility of the injected CO_2 stream with formation materials and formation brines;
- Absence of faulting or fracturing of the injection reservoir, or confining zone;
- Seismic risk considerations (Appendix 2-1).

These criteria were evaluated on the basis of the regional and local depositional and structural framework of the geologic section present under the proposed TEC plant.

2.2 Regional Geology

Figure 2-1 consists of a satellite image of Christian County identifying the area encompassing the proposed TEC site while Figure 2-2 provides a regional topographic map of the county and the project site's location which is situated approximately 2-miles north-northeast of Taylorville. A map of the drainage patterns in the area is shown in Figure 2-3, where smaller streams and drain to the larger lake features in the south and western portion of Christian County.

Illinois consists predominately of three physiographic provinces: plateaus, lowland, and plains as determined from the United States Geological Survey (USGS) which are shown in Figure 2-4. The TEC site lies in the Central Lowlands Province within the northern edge of the Springfield Plain of Illinois (Figure 2-5).

Major geologic features present in Illinois include arches and uplifts in the western and southern portion of the state, with the Illinois Basin dominating the subsurface of the central portion of Illinois (see Figure 2-6).

A stratigraphic chart of geologic formations present in central Illinois has been prepared and included as Figure 2-7. It has been adapted to detail the injection-confining formations of interest, the Mount Simon Sandstone injection interval, and the Eau Claire Shale primary upper confining unit, as well as including the shallower overlying formations. Shallower significant secondary confining seals and shale units are present in the geologic section, with the existence of the Maquoketa and the New Albany Shales. The base of the lowermost USDW is defined locally as those freshwater intervals where effective water usage occurs, and ranges from shallower near-surface glacial till aquifers to a conservative estimate of 250 feet. The drilling of the initial #1-injection well and subsequent wells will assist in specific depth and definition of this aquifer.

2.2.1 Evolution of the Illinois Basin

A review of current literature on the tectonics of the Illinois Basin and publications from Illinois State Geological Survey (ISGS) indicate that deposition of sediments during the Cambrian period was essentially continuous. The Mount Simon injection interval rock units in this permit were deposited during this time frame. Area information sources also indicate that deformation of the Illinois Basin occurred in Late Pennsylvanian times.

From the literature, it is generally recognized that the Illinois Basin began as a failed rift which formed near the end of Pre-Cambrian period in response to the breakup of a super-continent. High rates of subsidence in the resulting basin led to deposition of thick Early to Middle Cambrian sediments (see Figure 2-7 for a summary of the stratigraphic section). Compression associated with continental collision or associated with a simple increase of aesthenospheric drag at the base of the continental crust in the Late Paleozoic and Early Cretaceous reactivated deformation of faulted and folded structures. The subsequent structures developed during this event represent the first major deformational episode of the Illinois Basin. Any faults which may possibly have existed at the rift margins were inactive from Late Paleozoic time. Since the Late Paleozoic deformation affects all the pre-Pennsylvanian formations, the shallow well control can infer deeper structural features in the Injection Zone. These structural features provide and influence direct control over the long-term injectate migration and plume direction.

Throughout most of the Paleozoic Era, the ancestral Illinois Basin was open to the sea (Iapetus Ocean) southwest of Indiana and Illinois. This period was characterized by small rates of subsidence (whether thermally induced by crustal cooling or mechanically induced by the aforementioned aesthenospheric drag), slow sedimentary deposition, and by lack of tectonic activity (Collinson et al., 1988). The sediments deposited during that time are called the Sauk Sequence and were the product of a major marine transgression with only minor emergent areas at basinal margins (Collinson, et al., 1988). The Sauk Sequence in the region of interest -central Illinois - is approximately 4,500 feet thick and comprises the Potsdam Megagroup, which can be approximately 3,000 feet of mostly sandstones, siltstones and shales of Cambrian age, including the Mount Simon Sandstone, and the overlying Knox Megagroup, approximately 1,500 feet of mostly carbonates of Cambro-Ordovician age.

The TEC Mount Simon Sandstone proposed Injection Interval is situated within the middle to lower Cambrian age formations (see Figure 2-7).

Numerous major unconformities in this region occur at the top of the Knox Group, situated approximately 2500 ft above the top of the Mount Simon Sandstone injection interval. It represents the sub-Tippecanoe erosional surface on which the St. Peter Sandstone was deposited. Sedimentation of carbonates continued to predominate in a gently subsiding basin throughout the Middle Mississippian time; however, terrigenous sediments (shales, siltstones and sandstones) predominate in the younger aged rocks. At least one thick shale sequence (the Maquoketa) was deposited in Ordovician times.

The Mississippian and Pennsylvanian periods are bounded by large unconformities. The unconformity at the top of the Pennsylvanian represents more than 125 million years and is marked by the absence of the youngest Pennsylvanian, virtually all of the Permian section, and all of the Mesozoic rocks older than the Late Cretaceous.

2.2.2 Regional Stratigraphy

At the TEC site, interpretation of regional geology and stratigraphy is tentative because of a lack of data from well penetrations to the Mount Simon Sandstone formation. This is one of the goals for drilling, logging, and testing the TEC #1-injection well first to define the site-specific geology of the injection system.

2.2.2.1 Pre-Cambrian System

Due to limited information in this portion of the state, little is known about the Pre-Cambrian system other that it underlies the large Cambrian sedimentary sequence of the Mount Simon Sandstone. Figure 2-8 provides a regional structure map showing the deep basin extent and depth of these formations in central to southern Illinois. Information from 2D seismic data at the TEC site, and other regional projects show that this contour map requires adjustment and the Pre-Cambrian is undefined in some areas, while present deeper than the map suggests. Expectations are that limited reservoir potential will be found in these units due to age, reduction of primary reservoir quality and cementation and intergrowths of quartz present within the quartzitic sandstone formation matrix known to exist in other areas of Illinois.

2.2.2.2 Cambrian System

The sedimentary sequence of the Mount Simon Sandstone Injection Interval at the TEC site is part of a sequence of Cambrian age sediments deposited near the basinal axis of the ancestral Illinois Basin (Figure 2-8). There are no apparent significant lateral changes in formation thickness or basic physical properties of the rock units of the Mount Simon Sandstone Injection Interval (which lies within the middle-lower Cambrian) for distances on the order of several miles as confirmed by review and interpretation of the TEC 2D seismic lines (See Section 2.7) and the contour thickness map in Figure 2-9.

The Cambrian age rocks that underlie all of Illinois are assigned an early Late Cambrian age and include the Mount Simon, Eau Claire, Ironton/Galesville, Franconia, Potosi, and Eminence Formations (Figure 2-7). The Cambrian rocks in Illinois consist predominantly of sandstones and rest unconformably on top of Precambrian igneous rocks. In this region, due to adequate thickness, the Cambrian sequence of Mount Simon Sandstone injection interval is considered to have good potential for disposal as defined by the literature (Bergstrom, 1968; Visocky et al., 1986; Brower et al., 1989), and the from the current project underway through the Midwest

Geologic Sequestration Consortium (MGSC). The following individual stratigraphic descriptions have been generalized from standard references from the ISGS (Buschbach, 1964; Willman, 1975; etc.).

Mount Simon Formation

The Mount Simon Formation comprises the basal Cambrian unit, and will be penetrated initially by the proposed TEC Injection Well No. 1, and later developed with Injection Well Nos. 2, 3, and 4. In central Illinois, it consists mostly of fine-to-coarse-grained quartzose cemented sandstone, partially conglomeratic with varied amounts of silica cement and average thickness of approximately 1,800 feet. Beds of variegated micaceous shale, up to 15 feet thick, have been known to be interspersed and occur in the uppermost and lowermost section of the formation. The base of the Mount Simon is the sub-Sauk unconformity, while the contact with the overlying Eau Claire Formation is conformable.

Eau Claire Formation

In northwestern Illinois, the upper two-thirds of the Eau Claire Formation consists of shales, dolomites, shaly dolomitic sandstones, and siltstones that show rapid facies changes gradationally from one to another. However, in central Illinois, the Eau Claire Formation consists of predominant shale, while in southern Illinois generally it consists of dolomite and limestone.

The Eau Claire is an effective seal consisting of dense low permeability formations which will inhibit and contain migration of injected CO_2 from the deeper Mount Simon Sandstone injection interval.

This progression of rock-type from north to south indicates deepening of the ancestral water depths to the south from shallow, near-shore conditions to deeper marine facies near the depositional center of the ancestral Illinois Basin. This sedimentation pattern is observed throughout the Cambrian sequence. The Eau Claire Shale formation was observed and identified as a key marker overlying the Mount Simon Sandstone, with typical shale by velocities as documented in the seismic interpretation (See Section 2.7).

2.3 Surface Geology

The TEC site is located in Christian County within the Springfield Plain section of the Central Lowland Province (Figure 2-5), where the local terrain is very flat. The vegetation is dominated by cornfields and other row-crops. The generalized regional surface geology surrounding the proposed plant site is shown in Figure 2-10, where the local surface strata are Pennsylvanian in age, and consists of interbedded shale, sandstone, limestone and coal seams.

From CCG's proposed TEC site the Pennsylvanian rock exhibits a subtle dip to the southeast into the deeper portion of the Illinois Basin. The Illinois Basin is characterized by the filling in of younger sedimentary rock. Figure 2-11 identifies the glacial and alluvial till and known aquifers as determined in Christian County, while Figure 2-12 presents a map of the known background groundwater arsenic concentrations which are reported to be only 1 ug/l concentration at the proposed site.

Christian County, which lies in south-central Illinois within the middle portion of the Illinois Basin, is situated directly within Illinois Coal Fields (Figure 2-13). A detailed map in Figure 2-14 shows the mined coal seams, including the largest and extensive, the Herrin Coal Seam, south and east of the proposed site, the Springfield Coal Seam, and the Assumption Coal Seam, both situated east of the TEC site. A more detailed map in Figure 2-15 provides the thickness of the Herrin Coal Seams which have been mapped to be less than 66-inches thick in the immediate vicinity of the plant site and proposed injection wells. The map demonstrates the subtle synclinal pattern of the surface geology associated with the Illinois Basin with gentle dip occurring to the south-southeast. Figure 2-16 describes the specific coal beds and seam in relation to the larger geologic sequestration of the Illinois Basin. Multiple coal beds potential are present in these Pennsylvanian formations. Regionally, the exposed Pennsylvania, Mississippian and Devonian rocks can be characterized as follows:

> **Pennsylvanian** - Cyclic sequences of sandstone, red and grey shale, conglomerate, coal and limestone.
>
> **Mississippian** - Red and grey sandstone, shale and limestone.
>
> **Devonian** - Red sandstone, grey and black (organic) shale, limestone and chert.

2.4 Subsurface Geologic Potential of Stacked Reservoirs for CO_2 Storage

The MGSC have researched and prepared numerous reports on the existence of favorable subsurface geologic potential of stacked reservoirs for CO_2 storage in the stratigraphic column of central Illinois and the Illinois Basin geologic formations. Except for the Permian, most of the Paleozoic section is represented here, with the intervals can be sub-divided, for further analysis, into potential reservoir and seal units. In conjunction with numerous studies from area oil and gas exploration, as well as gas storage fields, there is sufficient knowledge of these formational units to characterize them as sinks or seals.

2.4.1 Potential Sinks or Reservoirs

Figure 2-17 is a Stratigraphic Column of geologic formations illustrating the considerable potential present in multiple horizons for use as sinks or zones of CO_2 long-term storage in the Illinois Basin. The major stratigraphic intervals present within the Illinois Basin were identified previously in Figure 2-7, and Figure 2-17 detailing the CO_2 storage potential of the shallower Pennsylvanian Coal Seams, the Mississippian and Devonian reservoirs, the Ordovician carbonates, and the Cambrian Mount Simon Sandstone formation.

The primary reservoir of interest at the CCG Taylorville site is the Cambrian age Mount Simon Sandstone. It consists of porous and permeable intervals, especially near its base. Furthermore, this sandstone formation is hundreds of feet thick providing ample volume for CO_2 storage. The sandstone is overlain by a very thick shale unit called the Eau Claire that has a broad lateral extent, and is considered a good seal because of its impermeability.

2.4.1.1 Comparison of Sinks and Reservoirs

Figure 2-18 contrasts the differences in a rock's particle size. It offers an understanding of a rock's detailed composition as a central theme in assessing its ability to store fluids and allow fluid to flow within it.

The Mount Simon Sandstone exhibits significant porosity between the sand grains leading to matrix permeability. With larger pore-throat size between the grains, there is an increase of the formation's permeability, and higher permeability values enable injected fluids to fill these pore volumes, with greater capacity, migrating further out onto the formation, and utilizing more available pore space in the injection sand matrix.

2.4.2 Potential Seals or Confining Beds

The reservoir confining unit is shale, which consists of tiny, clay-sized particles, dense and impermeable with very little available pore space to store any additional fluids. Any existing native fluids are tightly bound within, with limited movement, highly restricted by low permeability. Numerous potential regional confining seals have been documented by historical studies in the Illinois Basin. These include the overlying Cambrian-age Eau Claire Shale, Ordovician-age Galena carbonates, and Maquoketa Shale, and Mississippian-Devonian-age New Albany Shale.

The pre-Cambrian granitic basement serves as the lower confining unit in the system. The Mount Simon Sandstone lies on Precambrian basement rocks that are composed of granite, granodiorite, or rhyolite. Much of the Precambrian basement developed 1.48 to 1.38 billion years ago and is considered part of the eastern granite-rhyolite province (Leetaru, H.E., and McBride, J.H., 2009). At the TEC site, the anticipated top of the Precambrian is at ~6900 feet MD.

2.5 Structural Geology

2.5.1 Structure of the Mount Simon Sandstone

Figure 2-19 as prepared by MGSC depicts a general structure contour map of the Mount Simon Sandstone within the Illinois basin and shows the TEC site. The map was created using the available subsurface contour data. The Mount Simon is favored as a storage reservoir for its depth, reservoir porosity and storage capacity, and multiple confining units. The structure shows the top of the Mount Simon Sandstone and reveals the regional shape and extent of the Illinois Basin. At the TEC site the Mount Simon Sandstone is anticipated to be approximately 5,615 feet below ground level. Note that the contours in the figure are with respect to mean sea level. Other potential reservoirs (such as the St. Peter Sandstone) overlay the Mount Simon, and regionally, will follow a similar structural style.

2.5.2 Thickness of the Mount Simon Sandstone

The depositional thickness of the Mount Simon is not concentric with its structural top. It tends to thicken towards northeastern Illinois (Figure 2-20). At the TEC site the estimated thickness of the Mount Simon Sandstone ranges between 1,100 to 1,300 feet (estimated from seismic stratigraphic correlations), which is within the estimated 1,200 to 1,400 feet of thickness as based on the MSGC regional subsurface contour map.

2.5.3 Shallow Depth Oil and Gas Fields

There are a number of oil and gas fields near the TEC site with numerous shallow productive well, all with depths less than 2900 feet. None of the wells are deeper than the St. Peter Sandstone. For the purpose of evaluation at the TEC site, any well less than 2,500 feet is considered a shallow well.

2.5.4 Local Geology

A 30 by 30 mile area of interest (AOI) was selected for this project, largely to enable reservoir models to evaluate injection induced pressure changes at a distance from the TEC injection site. No Mount Simon Sandstone well penetrations currently exist in this immediate area so geological modeling, especially for deep sedimentary intervals is based on deep, distal wells. The proposed injection wells are shown in an oblique map view in Figure 2-21 situated immediately north-northeast of the town of Taylorsville, Illinois. The inner blue box represents a 10 by 10 mile study area, which was used to assess the scale of the injection plume once geologic evaluation and flow simulations were performed. At the center of the box are the modeled injection wells.

2.5.5 Seismic-Defined Local Geology

An interpretation of new 2D seismic data at the site revealed the gentle stratigraphic dip present in the area (Figure 2-21). The dip was determined to be less than one degree and strikes to the south-southeast, toward the deepest portion of the Illinois Basin. Figure 2-22 depicts the modeled geologic cross sections where a 15x vertical exaggeration is present which results in a visual appearance of significant dip. However severity of the dip in the figure is just an artifact due to the vertical exaggeration for visualization purposes. The less than one-degree dip will have a limited effect on the long-term migration of the CO_2 plume.

The seismic lines (shown in red on Figure 2-23) enabled a detailed localized interpretation of the subsurface stratigraphic horizons since no well control is available. The interpretations were conservatively extrapolated laterally outward from the proposed injection well locations to occupy the outer 30 x 30 mile modeled area. Figure 2-21 depicts a cut-away view of the proposed injection wells which are shown to extend from ground level and penetrating through the top of the Eau Claire Shale into the underlying Mount Simon Sandstone injection interval.

The 2D seismic lines revealed relatively uniform geologic bedding for the Mount Simon Sandstone, the Eau Claire Shale caprock, and the shallower overlying formations. Subtle sedimentary features were noted in the Mount Simon. These are likely because this formation consisted of an ancestral braided fluvial system which exhibits heterogeneity in thickness and reservoir properties. Interpretation of the seismic lines did not reveal the presence of faulting.

The seismic data reveals that the Mount Simon Sandstone rests on an interval referred to as the "Granite wash", which is considered to be the weathered and reworked materials from the underlying, granitic, Pre-Cambrian age ancestral continental basement. The Mount Simon Sandstone contains many reservoir quality intervals consisting of relatively clean sand with abundant pore space. Multiple Mount Simon Sandstone potential reservoir layers are shown in Figure 2-21, and likely represent direct variations of the formation's permeability, a key petrophysical property to consider when modeling the storage reservoir. The overlying Eau Claire Shale consists of much finer terrigenous particles such as silt and clay in a tight matrix. These particles compact into a plate-like form very tightly and exhibit limited porosity horizontally, and even more limited vertical permeability.

Above the Eau Claire Shale there is approximately 1,500 feet of the Knox Super-group that is largely characterized by the presence of dolostone of tight dense dolostone horizons that offer additional confinement. Above this unit lies approximately 180 feet of the St. Peter Sandstone which is also known for its reservoir properties. The St. Peter exhibits good pore space, and in some areas in Illinois it is used for the storage of natural gas. The St. Peter is overlain by Ordovician dolostone followed by a potential caprock, the Maquoketa Shale, which is approximately 200 feet thick. Maquoketa are more dolostones of Silurian and Devonian age.

At the transition of the Devonian and Mississippian is the regionally present New Albany Shale which has a thickness of approximately 125 feet. At approximately 2,100 feet below ground level, this shale represents an additional confining unit. Above the New Albany are alternating units of Mississippian limestone and sandstone which also offer some potential as confining units. Moving upward into the Pennsylvanian there are a numerous coal seams. These coal seams alternate with intervals of sandstone, shale, and limestone. Some of the shallow coal seams having been mined locally.

2.5.6 Seismically Derived Geologic Cross Sections

Two cross-sections for the 30 x 30 mile study area have been prepared from an integration of geological control and seismically mapped stratigraphy. Figure 2-22 shows a north-south cross section and an east-west orientation. These cross-sections illustrate the relative positions and thicknesses of the proposed Mount Simon Sandstone unit storage interval and the overlying primary and secondary caprocks and seals present in the area. The salinity of the St. Peter Sandstone is not known in the proposed project area. Data will be gathered during drilling of the TEC #1-injection well will define the salinity of this formation. South of the site, an underground natural gas storage site is present within the St Peter Sandstone at Hillsboro Field. This represents an active injection and storage site for natural gas in the St. Peter Sandstone.

Figure 2-22 does not show or depict in detail the dense, tight and apparently low permeability granite wash unit and the Pre-Cambrian age basement that underlie the base of the Mount Simon Sandstone Injection Interval. Further information on this lower confining unit to the Mount Simon formation will be determined from drilling of the TEC #1-injection well.

2.6 Seismic Survey Acquisition

2.6.1 Overview of Seismic Survey

WesternGeco, the seismic business segment of Schlumberger, was contracted by CCG Taylorville (through Schlumberger Carbon Services) to conduct a regional 2D reflection seismic survey over the proposed TEC site to determine if the subsurface geologic formations were suitable for carbon storage. The design of the project was developed in cooperation between WesternGeco and Schlumberger Data & Consulting Services (DCS) personnel in Houston and Denver.

WesternGeco seismic crew 1752 performed the survey with Conquest Seismic Services as the principal subcontractor. WesternGeco provided the Q-Land* point-receiver land seismic system MAS acquisition and processing equipment, plus technical and managerial personnel. Conquest provided the vibrators with Technicians and Operators, line movement vehicles, and necessary personnel to deploy and pickup the line equipment. The operation was supervised by a WesternGeco Operations Supervisor, Party Manager/Chief Observer, Project and Chief Geophysicists.

The preparation for the project started in early April 2009, with the county roads permitting process, and the field survey and data acquisition was performed between July 18, 2009 and August 3, 2009. The program comprised the following:

- Securing the necessary county road permits to conduct vibroseis operations on the survey's selected roadways.
- Surveying of Geophone Accelerometers (GAC) and vibrator point positions as per set field parameters.
- Field acquisition of surface 2D reflection seismic data via three seismic lines designed and performed by WesternGeco.

The Taylorville 2D seismic program was originally permitted for 44 linear miles, but actual production consisted of three 2D lines and was reduced to approximately 21.6 linear miles using an all vibroseis source. Crew 1752 was temporally based in Taylorville, Illinois at local motels, approximately 2 miles south of the project area and due to the short term duration of this project, no long-term field base was established.

Initial sweep tests were performed on July 22, 2009 after a start-up meeting with CCG Taylorville client representatives in the field and on the job site. Data acquisition of the 2D project initially began being collected on the July 23, 2009, and following after overnight preliminary data analysis of the sweep tests to determine the best sweep parameters to employ. The final field acquisition was completed on July 31, 2009, and final equipment rig-down and pick-up was completed on August 1, 2009. The project was performed with CCG's and Schlumberger's high Health, Safety and Environmental (HSE) standards insuring low impact to the community and proposed plant site area. During the project, no Lost Time Injuries or vehicle accidents were recorded. During overnight hours, one act of vandalism was reported, when field seismic equipment was hooked onto a vehicle and dragged down a road. A full report was made to the local CCG Taylorville representative and the local police, and no further incidents were reported during the seismic acquisition period.

2.6.2 Area Description

The seismic acquisition area was located in Christian County, Illinois just north of Taylorville (pop. 11,427), and situated approximately 30 miles to the south-west of Decatur (pop. 109,309). The area terrain is mostly flat croplands, with corn fields, and stalks as tall as 8 feet during the project acquisition. Prior to commencing the operation, scouting was conducted to identify the hazards that would be encountered, enabling the crew to implement prevention and mitigation measures by way of the Hazard Analysis and Risk Control (HARC) system. Driving was identified as the highest risk, especially with each intersection being considered “blind’ due to the tall corn fields growing right up to the barrow ditches.

The area is predominantly used for agricultural operations and consists of mostly private farms and lands. Access to the area is from Illinois State Highway 48 or 29. Within the project area, a land section line based network of gravel/paved roads exists with relatively sparse oil and gas field infrastructure present.

2.6.3 Weather

Throughout the project, weather was not a significant factor during the seismic acquisition, with temperatures varying during the day, ranging from a low of 65° F in the morning to a high of 85° F in the afternoon. During the project acquisition, a portion of one day was lost due to heavy rains the previous night before. On this day, during this event, the field crew stood by in the morning hours to allow for the area to dry out and resume access to roads.

2.6.4 Field Crew Personnel

Over the course of the project the assigned personnel on WesternGeco Crew 1752 was ramped up as the need required, and grew to a total of 34 members including subcontracted personnel. WesternGeco personnel included the following team:

- 1 Operations Supervisor
- 1 Party Manager
- 1 Chief QC Geophysicist
- 1 Project Geophysicist

2.6.5 Subcontractors and Vendors

Numerous sub-contractors and vendors were utilized by WesternGeco during this field data acquisition:

- Field surveying of GAC and Vibrator Points was conducted by Survey Technology Inc. (STI) from Katy, Texas.
- Conquest Seismic Services (Denver, Colorado) provided personnel for deploying and picking up line equipment, vibrator truck operators, and professionally trained flag personnel to control traffic flow around the vibrators.

- Vibra-Tech Monitoring Services from Houston, Texas provided pipeline and dwelling Peak Particle Velocity monitoring throughout the vibration portion of the project to insure and maintain proper distances from houses and pipelines.
- St Croix Seismic from St Croix, Wisconsin provided a Quality, Health, Safety, and Environment (QHSE) Adviser to assist WesternGeco Managers in training and compliance monitoring.

All subcontractors listed above have had a long term relationship with WesternGeco and are fully integrated and trained in the Schlumberger QHSE Management System.

2.6.6 Vehicles

Conquest Seismic Services provided 4 Hemi-44 truck mounted vibrators each rated at 46,700 lbs hold down weight. Twelve vehicles were also provided including F-350 jug trucks and F-250/F-350 pickups. Conquest jug trucks were equipped with special boxes fabricated for transportation of 3 LCU's of recording equipment: 30 DGS's and 6 ITO cables. MRU's and fiber optic cable, and batteries were transported by a regular pick-up truck. WesternGeco managers used 2 F-250 pickups.

2.6.7 Acquisition Chronology Summary

The following table provides a summary of the acquisition of data by date:

Date	Task
01 April 2009	Christian County road permit applied for
07 May 2009	Christian County road permit approved for 180 day period
18 July 2009	WesternGeco management arrives in Taylorville, IL
18 – 19 July 2009	Survey crews mobilized from Katy, Texas to Taylorville, IL
20 July 2009	Surveying started after start-up meeting with WG Ops Supervisor
20 – 21 July 2009	Acquisition crew mobilizes from Elmira, NY and Denver, CO
22 July 2009	Surveying completed and start-up meeting conducted with Acquisition crews and CCG Taylorville Client Representatives, layout of line 501 started and sweep testing completed
23 – 24 July 2009	Line 501 acquired and survey crews demobilize
25 July 2009	Standby in AM due to heavy rains the night before, complete pickup of line 501, commence recording on line 301 in afternoon.
26 July 2009	Sunday standby as per Christian County permit stipulations
27 July 2009	Lost 8 hours repairing line equipment damaged by vandals the night before, recording on line 301 late in the day
28 July 2009	Completed recording line 301
29 July 2009	Complete pickup of line 301 and start recording on line 101
30 – 31 July 2009	Line 101 acquired
01 August 2009	Final pickup completed, all lines inspected for trash
02 – 03 August 2009	Demobilization to Stanley, North Dakota

2.6.8 Operations

From an operational standpoint, the project was completed without any unexpected technical issues; however, there was one instance of equipment vandalism. Public interest in the project was high, with many people stopping by to see the operations, all having been well informed by the client representatives in the area regarding our operations. There were pipelines along the roadways, but with close communications between the pipeline company and the Vibra-Tech representative on site, the ability to continuously record data alongside the pipelines without exceeding agreed specifications for PPV. Data quality differences were observed when the vibrators were shaking on paved roads versus when shaking on gravel roads. Distortion readings were higher on the gravel roads due to the level of coupling, but this was not outside of preset specifications. Field brute stacks were generated each day after the day's production and overall data was considered very good quality.

2.6.9 Survey Design and Parameters

The survey's evaluation and design was a collaborative effort between the Integrated Solutions Group of WesternGeco and Schlumberger DCS in Houston and Denver. The design concentrated on the following key areas:

- Achieving very dense single sensor coverage to accurately identify any noise while preserving high frequency signals;
- Sweep parameter testing;
- Achieving a high resolution, error free field data set.

2.6.10 Subsurface Zones of Interest

The main objective and targets for the Taylorville 2D seismic data program were focused on the following geologic horizons:

- Eau Claire Shale @ ~5,151 – 5,615 feet (primary overlying caprock)
- Mount Simon Sandstone @ ~5,615 – 6,915 feet (storage reservoir)

2.6.11 Source Parameter Tests

A source parameter test program was conducted in two stages:

- On July 22, 2009, - a number of sweeps were recorded using the Hemi-44 vibrators. Tests were recorded into the active spread from the east end of line 501. Sweep parameters used during this testing stage are present in Table 2-1. The tests were supervised and evaluated on site by WesternGeco personnel.
- Results were analyzed on site for evaluation and selection of production sweep parameters, which was performed by the same field experts. A Linear 6-100 Hz 14 sec. times four phase rotated (90°) sweeps with three vibrator source was chosen for production.

2.6.11.1 Line Parameter Tests

A project parameter test program was conducted as indicated in Table 2-1, below:

Table 2-1
Seismic Project Parameters

TAYLORVILLE 2D - 2009			
Line	**Total Receiver**	**Total ITO**	**Total Sources Position**
Line 101 (N-S)	4884	407	407
Line 301(E-W)	3720	310	311
Line 501(E-W)	2808	234	231
Receiver		**Source**	
ITO - ITO	120 ft.	VP - VP	120 ft.
GAC - GAC	10 ft.	Vibes in linear pattern	3
Sweep type	Linear	Start Frequency	6 hz
Sweep Length	14 sec	End Frequency	100 Hz
Listen time	4 sec	Force Hold Down	70%
Taper type	Blackman		
Start taper	0.3		
End taper	0.3		
	Phase Shift		FULL SPREAD
Sweep 1 (V1)	0 deg.		2112 Channels
Sweep 2 (V2)	90 deg		
Sweep 3 (V3)	180 deg		
Sweep 4 (V4)	270 deg.		

2.6.12 Permit Summary

WesternGeco secured the county road permit and STI completed the One-Call for utilities and pipelines once the line locations were established. A total of 44 miles was originally permitted, consisting of one north-south line and four east-west lines between State Highways 29 and 48. Refining the scope of work, the original 44 miles was reduced to a total of 21.6 miles that offered the greatest representation of the subsurface. The county road permit was valid for 180 days from May 7, 2009, but can be renewed for future lines in the area. Mineral permits were not required by Illinois State law unless drilling greater than 3 feet into the ground. Surface owners were all notified by flyers and knocking on each individual's door along the road lines the seismic crew recorded. Overall, there were no permit issues encountered on the project.

2.6.13 Survey Summary

The main volume of survey operations in the Taylorville 2D project was carried out between July 20 and 22, 2009 by STI survey crews. An orientation meeting between the survey crew and WesternGeco's Operations Supervisor was held on July 19, 2009, and geodetic controls were established on July 20, 2009. Surveying commenced on July 20th, with 2 field crews active daily, plus a Field Supervisor. An average production of 2,074 single sensor points per crew was achieved, with peak daily production of 5,291 positions. A total of 949 VP's and 11,406 Single Sensor positions were surveyed. The survey team was based out of Katy, Texas and consisted of:

- 1 Chief Surveyor / data processor / mapper
- 2 rover pack operators
- 2 survey helpers
- Trimble R8 GPS receivers with Trimble Internal radio transmitters
    - matching the number of crews
    - + 1 used by chief surveyor
- 1 Trimble R8 GPS receiver base with Trimmark 3 radio transmitter
- 2 crew cab trucks

2.6.13.1 Survey Control

Static control survey was established prior to conducting the survey operations with 2-hour sessions at each station. All raw data was processed by the crew, with control information converted to the local grid coordinates and heights, which were later delivered to the crews. The Chief Surveyor converted this information to SEG-P1 format and combined both: control SP1 and pre-plot sp1 to create QLD file to run RTK survey. Both control and RTK check points were fixed with ~14" long rebars, with marked and labeled caps driven to ground level. No permanent markers were placed during the Taylorville 2D survey.

Table 2-2

Seismic Survey Control Stations

Station	Easting NAD27, ft	Northing NAD27, ft	Ellipsoidal height, ft	Ortho height, ft
TV 101	744842.9180	1069185.3231	605.722	500.055
MA5011961	752575.3214	1068160.6635	611.0812	505.3421

Table 2-3
Survey Parameters used in Taylorville 2-D Project

Datum Name	NAD27
Ellipsoid Name	CLARKE 1866
Semi-major axis	6378206.400
Reciprocal of flattening	294.97869820
Datum Shift Method	NADCON
Shift file	Conus
Projection System	Illinois West 1202
Projection Type	Transverse Mercator
False Northing	0.000 usft
False Easting	152400.305 usft
Origin Latitude	36° 40' 00.000" N
Origin Longitude	090° 10' 00.000" W
Scale Factor	0.999941177

2.6.13.2 Real Time Kinematic Surveying

Source stations and Intelligent Take Out (ITO) positions (e.g. Figure 2-24) were marked with fluorescent paint spots on the roads: pink for receivers and orange for sources. For better visibility fluorescent flagging tape of matching color was used on stakes. The survey settings were as listed in Table 2-4.

Table 2-4
RTK Survey settings

Elevation Mask	13
Number of satellites tracked	5
PDOP	5
HDOP	3.5
VDOP	5
Epoch Interval	1 sec.
Point Occupation	1 epoch (initially – 3 epochs)
Max. Range from Base Station	10 km (~6.25 mi)
Horizontal staking out accuracy	1 ft
Max. inline single sensor offset	9 ft

The staking accuracy of 1 foot was maintained when laying out points, unless prevented by terrain or obstacles, with 9 feet inline being the most common offset on roads. Crossline offsets were not applicable in 2D mode on roads. Both source and receiver offsets were mostly due to houses and pipeline obstacles, with their contributing amount deemed minimal.

2.6.14 Processing Results & Quality control

The survey software used for daily quality control of Real Time Kinematic (RTK) data was GPSeismic™ version 2006.4. The data acquired in the field was checked against the technical Global Positioning System (GPS) (Table 2-4) and offset criteria. Once the data quality was deemed satisfactory the data was incorporated into the survey database. In the database, additional analysis was run to determine the displacement against the pre-planned coordinates, as well as any missing station through a set of pre-defined queries. If the quality or differences from the pre-plot were out of acceptable range, field re-observations would be done. The final data was exported in NAD27 values and local height and submitted to the Geosupport department. Maps were generated to facilitate recording and survey crew operations. The line locations are shown on Figures 2-25a and 2-25b.

2.6.15 Recording

2.6.15.1 Operations Description

The Taylorville 2D line operations commenced on July 22, 2009 with line personnel supplied by Conquest Seismic Services, consisting of 1 team of 10 personnel, 3 traffic control persons, 3 trouble-shooters, and 1 Head Linesman. The cable team was responsible for the layout and pick up of line equipment, and the trouble-shooters were responsible for the fiber optic backbones, replacing the bad equipment from the lines and for changing batteries.

Table 2-5

Seismic Cable Crew Personnel

	Personnel	Total
Front and Back Crew (1)	10	10
Traffic Control	3	3
Trouble shooters	3	3
Head Lines men	1	1

Only minor damage was sustained by line equipment during the project during normal operations, except for the loss of 5 ITO cables and 3 DGS strings due to vandalism resulting in a loss of 8 hours to repair the line. The amount of equipment brought to the project was sufficient to lay out entire lines and enable efficient rolling from one line to the next. Line and recording operations were performed during light hours and not allowed on Sundays as per Christian

County permit restrictions. At around 7:00 am the crew would leave from Taylorsville after the morning QHSE/Operations meeting (approx. 10 minute drive) via highway 48 to the area.

The Q* point-receiver seismic acquisition and processing methodology MAS recorder was set up in a custom built utility trailer, powered by a 7.5kVA electrical diesel generator, mounted in the rear of the trailer frame. One AC unit was providing the climate control. This trailer also served as a field office, QC control, Data Processing, and proved adequate for operational use. Recording trailer was set up at line intersections of 501 & 101, and 301 & 101 to allow multiple lines to be recorded from each site.

2.6.15.2 Recording Equipment

The recording instrument was the single sensor WesternGeco Q-Land MAS system. The Digital Geophone String (DGS) is made up of 12 GACs which have the digitizer and acceleration coil element integrated in one case. A pre-amplifier amplifies the coil response earth's movement and signals are digitized at the sample rate. The source-receiver numbering scheme is shown on Figure 2-26.

2.6.16 Source - Vibroseis

Crew 1752 was equipped with 4 Hemi-44 truck mounted vibrators (Figure 2-28). The vibrators were fitted with Pelton VibPro electronics version 10C software. The fundamental ground force was 32,690 lbs. (70% of maximum hold down). Based on the sweep testing program, a three vibrator source array was chosen for the 2D project.

Table 2-6

Hemi-44 Enhanced Vibrator specifications

Specification	Value
Type	P-wave
Peak hydraulic force (lbf)	43,620
Maximum hold-down weight (lb)	46,700
Usable actuator stroke (P-P) (in)	3.00
Effective reaction mass weight (lb)	5,970
Effective baseplate weight (lb)	4,720
Baseplate clearance (in)	24
Gross vehicle weight (lb)	48,000

The vibrators underwent a continuous program of quality control checks. On a sweep-by-sweep basis the vibrators were monitored by the Quality Control (QC) status returns to the recording truck. Each day, 3 radio similarity tests were acquired for each vibrator. A set of hardwire similarity tests were recorded once the production sweep was determined. The table below gives the specifications that WesternGeco expects the vibrators to comply with. The crew found variability in the vibrator performance depending on the ground conditions. Particularly poorer distortion and signal were observed, when vibrators were on gravel road surface, which contrasted with vibrator performance when the vibrators were on the paved road surface (Figure 2-27). Even on the gravel surfaces, specifications were not exceeded, but were just not as good as those acquired on the paved surface.

Table 2-7

Vibrator Quality Control

Specification	**Value**
Average sweep phase not to exceed	5 degrees
Peak sweep phase not to exceed	10 degrees
Average sweep distortion not to exceed	25%
Peak sweep distortion not to exceed	35%
Variation of average sweep force from target force	20% in time, <2dB in FK domain

Prior to mobilizing to the 2D survey area, all line equipment was tested at the Carlsbad, New Mexico crew base as part of the maintenance program, plus underwent daily tests on the project as per procedures. The following tests were performed as part of the start-up and acceptance tests for the WesternGeco Q-Land MAS and the Hemi-4 Vibrators, for the acquisition of the Taylorville 2D Survey.

- Start Time adjusted for optimum +/- 20 µsec delay between all vibes and RT
- Radio Similarities
- Hardwire Similarities on production sweep

A full series of daily instrument tests were run and the results generated by the instrument were cross checked in the QC section by independent third party software Testif-I version 2.0.2a. The tests performed included the following:

- Total Harmonic Distortion, recorded at 12 dB pre-amp gain, 2ms sample rate.
- Noise, recorded at 12 dB pre-amp gain; 2ms sample rate. Pulse Test, recorded at 12 dB pre-amp gain, 2ms sample rate.

- Gain Accuracy, recorded at 12 dB pre-amp gain, 2ms sample rate.
- CMRR, recorded at 12 dB pre-amp gain, 2ms sample rate.

2.6.17 Field Geophysics Quality Control

The main tasks of the Field Geophysics department during the survey are sub-divided into two distinctive stages:

- Pre-acquisition
    - QC of survey data.
    - QC of source points placement.
    - Generation of shooting scripts for the Q point-receiver seismic acquisition and processing methodology.
- Post-acquisition
    - Geosupport
        - QC of vibrator positioning.
        - Processing and QC of instrument tests, hardwires and vibrator similarities.
        - Generation of Shell Processing and Support (SPS) files.
        - Generation of daily production report.
    - In-field Data Processing
        - Generate and QC correlated data.
        - Test data pre-processing and display.
        - Noise attenuation and Digital Group Forming
        - Generation of infield brute stacked volume

2.6.17.1 Pre-Acquisition Quality Control

Original pre-plot positions of sources, and in exceptional cases – of receivers, were revised based on updated infrastructure maps, satellite imagery and information coming from the survey and recording teams.

- Offsets

  Due to being in 2D mode, all points were confined to the road access, so no offsets were used.

- Source skips

  Due to being in 2D mode, all skipped source points were made up at 60' intervals on each side of the relevant skipped area.

- Shooting scripts

  Scripts were generated from SPECS for each 2D line independently, and then modified manually to make them more efficient for observer usage. When there was sufficient time, skipped VPs, identified during post-survey scouting and removed from scripts. Updated scripts with scouting notes were passed on to observers.

2.6.17.2 In-field Processing Quality Control

The main tasks of the In-Field Data Processing Group during the survey were:

- Correlate raw data and QC after correlation.
- Produce sweep test record plots and frequency analyses.
- Apply geometry from SPS files and QC.
- Perform noise attenuation and Digital Group Forming.
- Process post-DGF data through field 2D Brute Stacks.

2.7 Seismic Interpretation

This project consists of three 2D seismic lines located in Christian County, Illinois (Figures 2-25a, 2-25b). Seismic processing of data was performed using Omega* seismic data processing software with velocity analysis performed using the WesternGeco Interactive Velocity Analyser (InVa) software. The primary objective was to produce a time-migrated dataset with superior imaging of the subsurface to determine reservoir suitability for CO_2 storage. The data were acquired with very strong noise trains. An example of field brute stack for Line 501 of the first velocity profile and the post-line completion is present in Figures 2-29 and 2-30). Additional computer center filtering, processing was required to produce final interpretable data. Data noise and multiple attenuation were the main challenges encountered during processing.

2.7.1 Data Received

After substantial processing by WesternGeco, Schlumberger Carbon Services received three enhanced Kirchhoff pre-stack migration (KPSTM) 2D seismic lines for interpretation of the subsurface at the Taylorville site. The data consisted of one North-South (N-S) trending 2D seismic line (Line L-101) and two East-West (E-W) trending lines, Line L-301 (Figure 2-24) and Line L-501 (see Figure 2-25).

The three seismic lines were loaded into Petrel* seismic-to-simulation software along with the position of the proposed TEC injection wells (Figure 2-31 and 2-32). The lines have a depth in time of 4000 millisecond or ms. The three proposed injection wells were placed 2-miles apart and have a surface elevation of 612 feet and a total depth (TD) of 7501 feet.

2.7.2 Seismic Data Evaluation and Interpretation

Reviewing the Taylorville seismic data, a number of near-surface notches or gaps became apparent, Figure 2-26. The seismic acquisition team, observed and noted the presence of these gaps in the seismic data, and attributed these items to using a low-impact surface acquisition method that required omitting acquisition adjacent near peoples' homes, over natural gas pipelines, and other delicate infrastructure features. The seismic trucks pass by or over these features without activating their vibration pads (Figure 2-27 and 2-28). Overlaying orthophotos with the seismic data (Figure 2-33) confirms the concurrence of the gaps (Figures 2-32 and 2-33) with the location of farm houses.

2.7.2.1 Seismic Line L-101 (N-S)

Seismic Line L-101 is along North 1400 E. Road and trends from North to South. All three of the proposed TEC injection wells are adjacent to this line; the proposed TEC #1-injection well is shown with modeled gamma ray data for the overlying Eau Claire Shale confining interval and the Mount Simon Sandstone Injection Interval incorporated into the layer definition.

Schlumberger evaluated Seismic Line L-101 (Figure 2-34), along with the ISGS, and concurred that the top of the Eau Claire Shale is present at about 740 to 750 milliseconds (ms). The Mount Simon Sandstone / Pre-Cambrian granite wash contact is situated at about 980 ms (Line 101).

From earlier work, the ISGS estimated velocities for the Mount Simon Sandstone ranging between 14,500 feet/sec and 15,800 feet/sec. The range of the Mount Simon/ Eau Claire geologic contact is from 780 to 820 ms two way travel (TWT). Reviewing and working with these ranges and values generates a range of possible Mount Simon Sandstone injection interval thicknesses. Table 2-8 shows the calculated thickness of the Mount Simon Sandstone for both a shallow and deep interpretation of the Mount Simon and using range of seismic velocities possible. These two acoustic velocities represent the range of velocities characteristic of the Mount Simon Sandstone formation. Based on these assumptions, the resulting four combinations yield a minimum thickness of 1,160 feet and a maximum thickness of 1,580 feet for the Mount Simon Sandstone as determined from the seismic evaluation.

Table 2-8
Calculated Thickness of the Mount Simon Sandstone from Seismic Velocities

Contacts	**Time (TWT)**	**Thickness* (TWT)**	**Velocity ft/s**	
			14500	**15800**
Top of Eau Claire	740 - 750 ms		Calculated Thickness#	
Top of Mt. Simon – Shallow	780 ms	200 ms	1450 ft	1580 ft
Top of Mt Simon - Deep	820 ms	160 ms	1160 ft	1264 ft
Precambrian - Mt. Simon Contact	980 ms			

#Calculated thickness is with respect to the Pre-Cambrian base.

All three seismic lines (Line L-101, L-301, L-501) appear to have a little upward bend at their ends and this is indicative of loss of fold (a measure of the redundancy of common midpoint seismic data). As one approaches the end of the seismic line data there are fewer geophones to receive the seismic waves and more scatter and can often produce anomalous and odd artifacts at the end of the lines. It is more reasonable to discount and ignore these upward bending features (at each end of Figure 2-34) as they are likely artifacts of the data collection and processing.

Figure 2-34 also appears to show some disruption within the Mount Simon Sandstone on the northern end of the Line L-101. Any faulting in this region would be that of tensional system characterized by normal faulting with fault-dips of approximately 60 degrees. Observed here is a near-vertical disruption that does not match the known regional faulting behavior of the Illinois Basin. A more likely explanation for this feature is attributed to its proximity to the edge of the roll-off and the roll-off's migration pull-up effects.

Transition from the high-velocity, dolomitic Knox Group into the slower velocity Eau Claire Shale produces a strong acoustic impedance contrast resulting in high seismic amplitudes. This reflection denotes the Knox – Eau Claire boundary (Figure 2-37). Moving deeper in the section from the Eau Claire shale into the Mount Simon Sandstone this is not as strongly apparent. However, the Mount Simon Sandstone structural and formation top was picked, based on the relative thickness of the gamma ray well log. This log helps identify the transition from a shaly clay-rich rock into a "cleaner" quartz-rich (or lime-rich) rock, in this case the Mount Simon Sandstone.

While the Eau Claire Shale confining interval can exist as a broad (flooding) surface of regional extent, the Mount Simon Sandstone is believed to consist of a braided fluvial facies. The sedimentary structures associated with the braided features introduce considerable geologic and reservoir heterogeneity into this rock unit. This heterogeneity produces subtle features in the seismic response which can make interpretations of structural and formation geologic tops complex and challenging. The degree of cementation or alterations in matrix and cementation are excellent examples of this. One example of this is present in Figure 2-35 where the formation tops of the Mount Simon and the deeper Pre-Cambrian section can become ambiguous in places west of the proposed "North" well. These subtle features are not unique to this seismic line or this area. A small hump is seen in the shallower seismic data near the proposed well, and given some of the near-surface gap in the seismic data, this may be a subtle effect and an artifact due to data processing. A similar hump is not seen in Line L-101 which intersects at this location.

It is not uncommon for greater geologic heterogeneity to exist in a specific direction of formations. With only 2D seismic lines it is difficult at best to discern the direction of the braided stream network. Working with a higher resolution 3D seismic data set has a far better chance of discerning subtle sedimentary features such as braided streams.

2.7.2.2 Seismic Line L-301 (E-W)

Seismic Line L-301 trends east-west along the northern edge of the proposed TEC facility. The location of the proposed TEC #1-injection well is situated next to the line (Figure 2-35), with analog well log data again suggesting the vertical extent of the Eau Claire Shale confining interval and the Mount Simon Sandstone proposed injection interval.

2.7.2.3 Seismic Line L-501 (E-W)

Seismic Line L-501 trends east-west along the northern edge of the proposed TEC facility Taylorville property. The location of the proposed TEC #1-injection well is situated next to the line

(Figure 2-36), with analog well log data again suggesting the vertical extent of the Eau Claire Shale confining interval and the Mount Simon Sandstone proposed injection interval.

2.7.3 Seismic Time-Depth Horizons

Synthetic seismograms were also created for each well based on analog sonic and velocity data. These data were used to help verify the interpretation of the geologic formation top picks. The synthetic seismograms as well as the gamma ray data (Figure 2-37) are used to identify the top of Eau Claire Shale effectively.

Studying the entire 2D seismic data, no discernable faults were apparent dissecting the Paleozoic section. Subtle features within the Eau Claire Shale and the Mount Simon Sandstone exist, however there is insufficient vertical displacement or extent to support the presence of significant faults, and many could be related to depositional features.

An interpretation of the complete seismic data resulted in picking a few horizons (geologic formation tops) at the Knox-Eau Claire formational boundary and deeper. Mapped seismic surfaces were generated based on these data and were extended out over the 30 x 30-mile square area, Figure 2-38. Working with analog well sonic borehole formation velocity data, a depth conversion of an interpreted horizon (the top of the Eau Claire Shale) was performed. This resulted in an interpretative horizon selected and confirmed in the depth domain (feet). Using this as a template, a horizon was subsequently generated to intersect the proposed TEC #1-injection well at a depth of 5,615 feet for the top of the Mount Simon Sandstone Injection Interval. Furthermore, based on analogue well data indicative of the Mount Simon Sandstone in the region, a set of 27 underlying zones (model layers) were generated between the top of the Mount Simon Sandstone and its base, the granite wash, Figure 2-39. These zones were subsequently layered as direct flow layers and populated assigned with reservoir properties (i.e. porosity and permeability) for use in reservoir flow simulations of the injection interval. The reservoir model, originating from the seismic interpretations, dips to the southeast by no more than one degree.

2.7.4 Stratigraphy

The interpretation of area seismic data provides key information on the structure, thickness, and distribution of the candidate injection reservoirs and the lateral continuity of the confining formations and sealing intervals associated with the proposed TEC injection wells in Christian

County. The New Albany Shale formation reflectors are the shallowest recognizable reflectors present immediately below the lowermost Mississippian section. In addition to the New Albany, tops for the Maquoketa Shale, Knox Group, Eau Claire Formation, Mount Simon Sandstone, and informal units in the Pre-Cambrian are also recognized and interpreted on the line.

2.8 Injection-Confining Formation Characteristics

Formation characteristics are described below for the identified potential injection intervals, and a include detailed discussion of confining intervals, serving as overlying immediate confining beds and regional seals and additional low permeability confining strata.

2.8.1 Injection Interval

The primary reservoir test objective in the proposed TEC #1-injection test well is the Mount Simon Sandstone, where multiple reservoir sections are expected if sufficient thickness and reservoir quality is encountered. Figure 2-40 from USGS Water Atlas identifies the regional salinity and hydraulic head of the Mount Simon Sandstone, and Figure 2-41 provides the thickness and known salinity contours (Note: there is little information from drilled wells present near the TEC and in central Illinois).

2.8.1.1 Mount Simon Sandstone

The Mount Simon Sandstone has been extensively developed for disposal and storage using Class I injection wells in Illinois and Indiana, and is the main deep saline candidate reservoir being targeted for CO_2 storage at this site. Three identified characteristics of the Mount Simon Sandstone, as determined by ISGS and the MGSC, make it very suitable for injection at Taylorville and the area near the proposed TEC #1 well:

1.) The Mount Simon Sandstone is deep in the subsurface of the Illinois Basin and site 2D reflection seismic interpretation indicates it is laterally continuous in this area;

2.) It is of sufficient thickness to be used for CO_2 storage;

3.) Preliminary results of the MGSC project in Decatur suggest sufficient reservoir potential is present with porosity and permeability.

Analysis of whole and sidewall cores throughout the Illinois Basin show porosity in the Mount Simon Sandstone is variable with location, can decline from ~20 % at shallow wells near surface to

< 5 % at 8,000 feet well depths due to cementation and matrix. Data from wells drilled in deeper portions of the Illinois Basin indicate that porosity-reducing cements in the Mount Simon Sandstone are quartz and potassium feldspar overgrowths with lesser hematite, kaolinite, chlorite, chert, and carbonate.

2.8.2 Confining or Sealing Intervals

Above the proposed Mount Simon Injection Interval at the proposed TEC #1-injection well, there are thick sealing formational units (Figure 2-7). From deepest to shallowest the overlying seals are:

- The Eau Claire Formation overlying the Mount Simon Sandstone;
- Dense dolomite sections within the Knox Group;
- The Maquoketa Shale overlying the Trenton-Black River section;
- New Albany Shale.

USGS has summarized these confining sealing units in Figure 2-42.

2.8.2.1 Eau Claire Formation

The Cambrian age Eau Claire Formation is an immediate confining interval (Figure 2-42) above the Mount Simon Sandstone injection interval. The Eau Claire is estimated to be encountered at 5,115 feet drill depth (as determined from seismic evaluation). The Eau Claire is approximately ~500 feet thick at the proposed test well site and will likely consist of dense, tight, very low permeability shales, thin very well cemented sandstones, and thin dense carbonate rocks all of which form the sealing characteristics of the unit.

In the proposed TEC #1-injection well, a conventional core will be taken in the Eau Claire Formation to collect site specific reservoir and confining interval rock property data on its qualities as a reservoir seal.

2.8.2.2 Knox Group Formation

Much of the overlying Knox Group dolomites are composed of impermeable, dense dolomite that act as multiple seals above potential candidate reservoir The dense dolomite sections in will provide effective secondary reservoir seal.

2.8.2.3 Maquoketa Formation Confining Seal

The Ordovician Maquoketa Shale also serves as a reservoir sealing unit in the eastern Mid-continent and Illinois Basins. At the proposed site, the Maquoketa Shale is estimated to be present at an approximate depth of 2600 feet and estimated to be approximately 200 feet thick as based on local seismic data interpretation subsurface mapping.

2.8.2.4 New Albany Formation Confining Seal

The Devonian New Albany Shale is considered to be a regional petroleum reservoir sealing unit in the eastern Mid-continent area of the United States. It is estimated to be approximately 125 feet thick at the proposed well site based on seismic interpretation and present at a depth of approximately 2100 feet across Christian County.

2.9 Well Penetrations in the Area of Review

A map of oil, gas, and gas storage field fields surrounding the proposed TEC site is provided as Figure 2-43. It shows numerous shallow oil fields in Christian County, and several natural gas storage fields present in the immediate area surrounding the county.

A search of all well penetrations from State of Illinois well records in Christian County and within the area of interest (30 x 30 miles) is compiled in a regional map in Figure 2-44.

Detailed maps have been prepared as Figures 2-44a, b, and c, and focus on a 2.5 mile radius around the three base-case injection wells (TEC #1, #2, and #3). Modeling shows that the injected CO_2 will be contained within this well radius. This area has been overlain onto the land survey grid map with the proposed TEC facility boundary highlighted and labeled, and the locations of the TEC Injection Wells spotted. Figure 2-44a depicts and contains all identified well spots and locations, while Figure 2-44b contains all oil well locations, and Figure 2-44c contains the location of all water wells.

Table 2-9 provides a summary of categories of artificial penetration wells in the 2.5 mile area around the injection wells. It indicates that there are a total of 165 known wells present in this area. The distribution of wells consists of 31 dry and abandoned wells, 4 oil producers-active, 14 oil producers-plugged, 1 active salt water disposal well, 3 plugged salt water disposal wells, 6 temporarily plugged and abandoned or unknown wells, 19 coal test wells. Additionally, there are a total of 70 water wells, and 11 water well test holes, with one 'dead' permit well, which was likely never drilled.

Table 2-10 compiles all identified artificial penetration wells in the area sorted by ascending total depth, ranging from 0 feet to the deepest identified well, 2,701 feet. A more detailed review of all the wells is presented in Table 2-11 where the data has been sorted by well status and ascending total depth to determine categories of well type. The deepest well identified is still shallow of the St. Peter Sandstone at only 2,701 feet, since at the site, the St. Peter is expected at a depth of ~ 3,100 feet. Appendix 2-2 contains copies of well plugging affidavits and report for the wells in the 2.5-mile radius as found in the State of Illinois, Department of Mines and Minerals, Oil and Gas Division Well Plugging Affidavits and Reports files. Appendix 2-2A contains the plugging records for the three deepest drilled wells in the preliminary AOR, which are 2,701, 2,577, and 2,230 feet and Appendix 2-2A-1 is a composite schematics of these plugged deep wells.

On a regional scale, a considerable number of well penetrations are present in the original investigated area of interest and are graphically depicted in Figure 2-45. This figure indicates that of all the wells identified, none have penetrated the Mount Simon Sandstone, with the deepest well at approximately 2,700 feet, with most wells of shallower depths (Appendices 2-2, 2-2A). This area encompasses the AOR. Known water injection wells (Figure 2-46, and Appendix 2-2B-1), are all near or slightly below 2,000 feet, water production wells, mostly of < 300 feet (average depth of around 50ft), and some to near 2,000 feet (Figure 2-47), confidential wells, mostly shallow of < 500 feet (Figure 2-48), and all other well penetrations (Figure 2-49) are no deeper than 2,300 feet. This GIS-based review of data compiled from ISGS databases of wells indicates that there are no well penetrations to the Mount Simon Sandstone horizon in Christian County.

In Figure 2-50, only four wells are present within a 12-mile radius of the proposed TEC site that may have intersected the St. Peter Sandstone, a potential USDW. This area encompasses the AOR and indicates that no corrective action will be required for the project.

2.10 USDW within AOR

2.10.1 Groundwater Flow, Notable Waters and Underground Sources of Drinking Water

Depth to groundwater in Christian County including Taylorville typically occurs within 20 feet of ground surface. In the Sangamon River valley, depths to groundwater have been reported from approximately 5 feet below ground surface to approximately 20 feet below ground surface. Except where local draw down has influenced the water table, typical depths to groundwater in the glacial till aquifer is in the range of 15 to 20 feet below ground surface. In the vicinity of the TEC site, groundwater is obtained from the Glasford Formation (Figure 2-51) consisting of sand, gravel, and till. The Hagerstown Member of this Formation is of particular interest in this area. Taylorville and some nearby towns obtain their water from the “Hagarstown aquifer”, a deposit forming a nearly continuous ridge of sand and gravel with a characteristic northeast-southwest trend (Figures 2-52 and 2-53). The sand and gravel were deposited by a meltwater stream which was initially channeled upon or within the Vandalia ice sheet by a large linear ice crevasse. The stream cut a deep, narrow valley, reaching bedrock at some locations. The sand and gravel are probably in contact with the bedrock surface throughout most of the length of the deposit. Between Taylorville and Macon, the top of the sand and gravel is up to 30 feet higher than the surrounding Illinoisan till plain. South of Taylorville, the aquifer lies beneath modern stream valleys (Burris and Others, 1981).

A geologic cross-section C-C’ (Figures 2-52 and 2-53) through the Hagerstown aquifer was drawn from driller's logs and sample studies of washed cuttings from water wells. The cross-section is on the northeast sided of Taylorville and runs across the aquifer. The cross section reflects the steep walls of the valley and the narrow width of the aquifer. It can be seen that most of the laterally confining materials are glacial tills, which have very low water-yielding properties. Most of the recharge is through the overlying thin cap of loess which is very sandy at its base (Burris and Others, 1981). A thinner sand zone, situated approximately between 30 feet and 60 feet below ground surface is also recognized as part of the Hagerstown aquifer (Figure 2-54).

2.10.2 Notable water users and alternate sources

Increased water demand required the construction of Lake Taylorville in 1961-1962 by damming the south fork of the Sangamon River. The reservoir went into service in March 1963 and for two years very little groundwater was pumped. However, the treatment plant did not treat the surface water satisfactorily, and the wells were again put into service. Since 1965 surface water and groundwater have been blended (Burris and Others, 1981; and Dave Spiegel, Taylorville Water Department Superintendent, personal communication, 2010).

The lake has collected sediments through the years a plan to dredge the lake is proposed for March 2010. See:
http://www.taylorville.net/Comprehensive%20Plan%20for%20Lake%20Taylorville%20chapter%206.pdf

The Taylorsville Water Department http://www.taylorville.net/Water.htm reports that:
"At this time Taylorville operates a 4 million gallon per day treatment facility that provides water to nearly 18,000 residents in Taylorville and its surrounding communities. Taylorville is a lime softening/clarification and filtration facility which utilizes both surface water from Lake Taylorville and well water from the Macon-Christian strip aquifer for its raw sources."

In addition to Taylorville's municipal well field, there were two other large water users, Continental Grain and Hopper Paper. These two companies had their own wells (Figure 2-52) however at present, they purchase water from Taylorville.

The thin sandy zone of the Hagerstown aquifer is developed locally for private domestic wells (Dave Spiegel, Taylorville Water Department Superintendent, personal communication, 2010) and is present through most if not all of the CO_2 injection footprint. No irrigation wells were noted in the available information.

These local, surface aquifers are positioned approximately ~5200 feet above the injection formation (the Mount Simon). The relative vertical position of the Hagerstown aquifer with respect to the Mt. Simon is depicted in Figure 2-54 along a regional North-to-South cross-section adjacent to the three modeled TEC wells.

2.10.3 Groundwater flow direction

The static water levels in the north half of the aquifer dips from northeast to southwest. The average water level elevation at the north end of the aquifer near Macon's wells is about 630 feet, while at the Blue Mound and Moweaqua well fields the elevation is 624 feet. At Assumption's and Stonington's wells the average elevation is 614 feet, and at Taylorville the water table is about 596 feet (Burris and Others, 1981).

Non-pumping water levels are typically a uniform 10 to 15 feet below land surface except in the Taylorville area, where water levels have been depressed due to the effects of the comparatively high pumpage. Under normal conditions the general direction of groundwater movement would be from northeast to southwest, and natural groundwater discharge would be to the South Fork of the Sangamon River. However, the pumping centers at Taylorville effectively intercept groundwater flow toward the river (Burris and Others, 1981).

Local groundwater flow directions will be determined once the TEC system is in place and the monitoring wells have been constructed.

2.10.4 Groundwater Recharge

This local aquifer has a loess weathered drift cover of silt or clayey silt which is 10 to 20 feet thick. The lower 4 to 8 feet is usually very sandy. Most of the recharge comes through this cover, although some water may be replenished through the upper lateral boundaries of the aquifer. It is probable that very little water enters the aquifer through the compact tills of the valley walls or the bedrock shale beneath. The small sand lenses within and between the tills contribute little to the recharge of the aquifer (Burris and Others, 1981).

A site-specific determination of the base of the lowermost USDW will be made in conjunction with the proposed TEC #1-injection well. In central Illinois, the base of the lowermost USDW is very shallow, ranging from 125 feet to 200 feet across the AOR. For this study, the base of the lowermost USDW is estimated to be present at a depth of less than 250 feet below the surface, and will be determined from drilling and logging of the first injection well. Within the AOR, the depth of drilled and completed water wells situated in the usable shallow glacial till aquifers ranges from 19 – 130 feet as determined from water well records.

The casing program of the proposed test well is very conservative, and has designed surface casing cemented to the surface at a depth of approximately 400 feet to protect all sources of shallow drinking water and the indicated lowermost USDW.

2.11 St. Peter Sandstone Salinity

The St. Peter Sandstone may potentially have low salinity, consisting of < 10,000 mg/l TDS which could support it's designation as a USDW. Following drilling of the #1-injection well, fluid samples, and log calculations will be performed to determine the salinity of the St. Peter. Consideration should also be given to the fact that the St. Peter has been used regionally for waste disposal and no records show that it has been used anywhere in central Illinois for a water supply. If the salinity of the St. Peter is confirmed to be less than 10,000 mg/l TDS , and if required by the US EPA Director, TEC has developed a contingency program within the well design to address it and protect it behind intermediate (13-3/8-inch) casing set to an estimated depth of 5,115 feet.

Figure 2-55 contains USGS compiled data (USGS Water Atlas 730-K) on the distribution and salinity of the St. Peter Sandstone aquifer in central Illinois. It shows that near the proposed TEC site, salinity of the St. Peter may be near 10,000 mg/l TDS. Data from the literature (Figure 2-56) shows similar information that the site may be near the 10,000 mg/l TDS contour. The potentiometric surface of the St. Peter is indicated from USGS data in Figure 2-57.

2.12 Regional Hydrology and Groundwater Aquifers

Other regional near surface groundwater aquifers are primarily of Pennsylvanian age (Figure 2-7), and are directly related to the depth of glacial till present in the near surface. Figure 2-58 details the location of known glacial till aquifers (unconsolidated) and their distribution across central Illinois, while Figure 2-58a shows the consolidated aquifer distribution.

Figure 2-58b shows the thickness and depths of these Pennsylvanian age sandstone and some limestone aquifers which serve most of Christian County are generally near 100-200 feet with local variability, while Quaternary age glacial aquifers range from 100-300 feet deep (Figure 2-58c).

A map of generalized surface geology showing shallow formations which can serve as groundwater aquifers is presented in Figure 2-58d.

2.13 Seismicity and Induced Seismicity

The TEC site exhibits low risk from significant seismic events. According to the USGS seismic hazard web site (USGS, 2009, see URL), peak ground acceleration (PGA) for the TEC site in central Christian County is 3.5 % g with a 2 % chance of exceedance in 50 years (Figure 2-59).

USGS and National Earthquake Information Center (NEIC) data from various central Illinois earthquake and seismic data catalogues for the Christian County area have been compiled in Appendix 2-1. Figure 2-60 contains a map of Illinois as generated from USGS and NEIC earthquake catalog data. The maps and an earthquake database both indicate only one historical earthquake present in the county over 20 miles southeast of the proposed location with a magnitude of 3.2. The main earthquake activity lays hundreds of miles south in southern Illinois toward the New Madrid fault area and the deeper portion of the Illinois Basin.

Induced seismicity from injected operations is not expected to be a concern during this project due to the great thickness of reservoir present in the Mount Simon Sandstone and its apparent favorable permeability. Additionally, there are no known mapped faults near the TEC injection well, and based on the volume of future CO_2 planned for injection, fluid migration in the Mount Simon will not encounter any known faults in the up-dip direction, the direction of apparent buoyancy-driven CO_2 migration.

3.0 RESERVOIR MODEL – BASE CASE

Preliminary pipeline and reservoir engineering models to describe the TEC site were prepared to assess the feasibility of utilizing the Taylorville site for CO_2 storage. The Area of Review and Corrective Action Plan includes a discussion of development of the AOR using the base case (three-well) and four-well injection model. Section 3.1 provides the steps required to obtain results from reservoir and well injection modeling for the Mount Simon Sandstone injection interval plume and pressure determinations, while Section 3.20 evaluates the pipeline and well sizing calculations that were performed using PIPESIM 2009. Modeling software used in this study included the following Schlumberger programs:

Petrel 2009.1	-	Seismic-to-simulation software, geological modeling, fine scale and simulation grid building, property population, results viewing
ECLIPSE* 300	-	Reservoir simulation software
PIPESIM*	-	Production system analysis software, nodal analysis

The model will be updated following completion of the first injection well. The location and construction of additional wells, and operational details will be optimized for the well field at that time.

3.1 Integrated Reservoir and Geologic Model

A geologic model for the Mount Simon Sandstone was constructed over a large area of central Illinois from the available geologic, geophysical, and petrophysical evaluation of all available data, including cores, 2D reflection seismic lines, and well logs (Figure 3-1).

This section describes reservoir modeling that was conducted using the ECLIPSE simulator with modeling results focused on a base case of injection through three injection wells. It is the primary tool used to predict results and identify formation intervals for the TEC #1-injection well. The following discussion outlines how this model was constructed. All modeling results indicate that this scenario is feasible. Model optimization tasks have been reviewed and have evaluated alternate cases (e.g. low-high, additional wells, etc.).

3.2 Dynamic Model

The simulation model is composed of the simulation grid along with rock and fluid properties, well completion, and pressure data. This section describes these components used to initialize the simulation model. To investigate the feasibility of handling the CO_2 at the prescribed rate, an integrated flow line and well flow PIPESIM model was setup (Figure 3-2) that was coupled with an ECLIPSE reservoir dynamic model (Figure 3-3). This covers the flow stream from the compressor to the reservoir.

The CO_2 storage option in ECLIPSE provides the means to include a CO_2 rich phase, an H_2O rich phase and a solid phase (salt content) (see Figure 3-4). The CO_2 rich phase is labeled the gas phase (Figure 3-10) while the H_2O rich phase is labeled the water phase (liquid phase). The mutual solubilities of CO_2 and H_2O are calculated to match experimental data for CO_2-H_2O systems under typical CO_2 storage conditions: 54-212 ^{o}C and up to 8,700 psig.

3.3 Simulation Grid

The Geo-cellular model described earlier in the geophysical section covers an area of 30 square miles. This model was defined to approximate the reservoir characteristics shown at the geophysical and log level. This results in a model which contains over 6.7 million cells. Each grid cell is 300 m x 300 m in areal extent with an average layer thickness ranging from 1.5 feet to 7.6 feet (see Figure 3-5). The simulation grid design was based on the fine scale static model with the following criteria:

- Preserve the horizontal resolution of the static grid in an area large enough to cover the majority of the possible extent of the CO_2 plume.
- Ensure sufficient vertical resolution to adequately model gravity segregation and effects of vertical lamination on fluid flow.
- Ensure the vertical resolution matches the resolution indicated by statistical analysis of log properties in critical layers.
- Limit the number of active cells to allow for a reasonable run time.

The static model was up-scaled to a coarser grid to address these objectives as described in the following sections.

3.4 Grid and Property Up-scaling

The dynamic model covers the full 30 x 30 mi^2 areal extent of the geo-cellular model. The fine scale geocellular grid (300 x 300 m grid cell size) was retained in the core area of the reservoir but was coarsened to the extents of the reservoir to allow reasonable run times. This resulted in the variable grid shown in Figure 3-5. The coarsest grid cells at the outer model boundary measure 2,400 x 2,400 m.

The dynamic model incorporated vertical up-scaling designed to minimize grids effects in the zones used for CO_2 injection. The vertical relationship between the geocellular model and the simulation model is shown in Figure 3-6 and 3-7.

Grid statistics are shown in Table 3-1 and illustrated in Figure 3-5.

Table 3-1
Grid statistics for the Geocellular and Simulation Models

Model	Dimensions	DX, m	DY, m	DZ Avg, ft	Total Cells	Active Cells
Geocellular	160x160x264	300	300	6.0	6,758,400	
Simulation	46x63x123	300-2,400	300-2,400	10.7	356,454	350,797

3.5 Porosity and Permeability

Porosity and permeability were populated based on analog well log data representative of the geology as described in the geological section. Permeability was up-scaled to the coarser simulation model using volume-weighted geometric averaging. Figure 3-8 shows good agreement between the available well log, geo-cellular and simulation model permeability. Porosity was also up-scaled to the coarser simulation model using volume-weighted arithmetic averaging. Figure 3-9 shows the good agreement between the log, geo-cellular and simulation model porosity. Vertical permeability is assumed to be 32 % of horizontal permeability. Sensitivities to these parameters will be addressed in the prediction cases.

3.6 Fluid Properties

The reservoir is assumed to be 100% brine saturated with a formation salinity of 97,000 ppm at 6,000 ft true vertical depth (TVD) at initialization.

For modeling purposes, the injected gas is assumed to have the behavior of pure CO_2 with the phase behavior illustrated in a pressure-temperature chart shown in Figure 3-10. At the expected range of pressure and temperature throughout the flow system, the CO_2 is likely to be either a liquid or a supercritical fluid (Figure 3-4). Hysteresis and solid precipitation are included in the model. Residual water saturation is 25 % whereas residual CO_2 saturation is 20 %.

3.7 Model Equilibration

The model was equilibrated as a normally pressured reservoir with a normal gradient of 0.433-psi/foot used. This equates to an initial reservoir pressure of 2,598 psi at 6,000 feet TVD and 3,002 psi at a bottomhole depth of 6,932 feet TVD. Reservoir temperature was calculated at 119^{o} F at 6,000 feet TVD using a temperature gradient of 1^{o} F/100 foot and ambient temperature of 59^{o} F.

3.8 Injection Well Modeling

All of the injection wells are planned to be completed as combined openhole and cased-hole completions with approximately the lower 400 feet of the 12-1/4-inch openhole section in contact with the Mount Simon Sandstone injection reservoir as shown in Figures 3-8 and 3-9. Additional up-hole perforated zones (through the 9-5/8-inch casing) will be developed as needed based on model optimization. All of the injection intervals will be confined to the Mount Simon Sandstone section.

The rate at which the CO_2 is injected into the formation is also constrained by the need to maintain the formation pressure below the level that would cause fracturing of the rock. This fracture gradient may be dictated by government policies that govern the rates at which a particular substance can be injected into a specific formation. Due to the lack of site-specific information on the Mount Simon Sandstone formation, an estimated pressure gradient of 0.65 psi/ft was selected to use in the Base Case Model run. With this constraint, a maximum injection Bottomhole Pressure (BHP) of 4,376 psi at the Mount Simon Sandstone mid-point of the completion (perforation) depth of 6,732 ft TVD was established. Additional sensitivity to this key parameter is addressed in the model prediction cases.

3.8.1 Simulator Controls

Injection rates can be controlled in the simulator in several different ways. For this study the maximum allowable injection rate of 239 lb/s was distributed between the three wells according to the well capacity and other modeling constraints. These controls set the maximum injection rate for the field and allowed the simulator to determine the injectivity of each individual well. In this situation individual wells could make up or re-allocate and use any excess injection rate due to wells which cannot meet any imposed constraints.

An average Tubing Head Pressure (THP) of 2,100 psi for each well was employed in the simulator, with actual THP as high as 2,220 psi.

As discussed previously a maximum BHP of 4,376 psi was employed to be below the indicated and calculated frac gradient, remaining conservative to avoid potential fracturing of the reservoir.

3.9 Model Predictions

The primary purpose of the dynamic model is to predict the effects of the injected fluid on the Mount Simon Sandstone reservoir. Additionally, the model results were configured to identify where the 3 TEC injection wells could accept the full capacity of the planned CO_2 injected rate using a minimum amount of wells with the well and surface network constraints. In addition, the areal extent of the migration of the CO_2 plume was investigated. To achieve these objectives a Base Case Model Run was constructed. To account for uncertainty in the geologic model, several cases and iterations assumed parameters and were run which varied individual model input parameters. The results are discussed in this section.

3.10 Base Case Model Run

The Base Case Model Run serves as a baseline to allow for direct comparison of other cases which incorporate uncertainties in reservoir properties and alternative development strategies. The Base Case is the best estimate of reservoir and surface parameters from the Mount Simon Sandstone, where little or no site specific information is present. The following input parameters were employed:

- Geological model based on seismic and analog well data
- Injection start date of January 1, 2015;
- Injection end date of January 1, 2045;
- Simulation end date of January 1, 2145;
- Fracture gradient of 0.65 psi/ft;
- Injection rate of 239 lbs/s of $CO_{2;}$

- Average THP of 2,100 psi for each well;
- Source pressure of 2,220 psi (maximum).

3.11 Injection Rate and Well Pressure Profile

The injection and cumulative injection rates are shown in Figure 3-11. The current model run utilizes the full capacity of CO_2 injection, and results indicate that it can be covered by the modeled wells, given the imposed BHP and THP limits of the estimated conservative fracture gradient of 0.65 psi/foot.

Figure 3-12 shows the injection and pressure profile during the simulation period. In the initial injection phase of injection, the wells are constrained by the fracture gradient pressure due to an unfavorable relative permeability ratio. As specified earlier, since the reservoir is initially saturated and filled with 100 % native brine as the connate fluid, the injection pressure must be higher to overcome this unfavorable ratio. As gas saturation increases the delta pressure between the reservoir and the wellbore decreases until it reaches a stabilized pressure for the TEC #1 and North wells. The final stabilized pressure of the Center well is slightly higher due to interference between the wells as the CO_2 plume migrates with continued injection. These stabilized pressures will be observed in subsequent model cases run to quantify uncertainty in the reservoir parameters.

Differences in THP and BHP in the wells can be attributed to the distance of the wellbore from the source and the change in density of the fluid as it migrates through the phase diagram referred. This effect can be seen in the bottomhole and tubing head pressure plots. As noted earlier, the actual effects of the change in density due to the change in pressure drop are not fully accounted for in the model. However, a close approximation is anticipated given the current model constraints and assigned conservative parameter values due to lack of site specific values.

3.12 Model Predicted Pressure Profile

The model predicted pressure response plots to CO_2 injection are shown in Figures 3-13 to 3-19. For these figures and plots the reservoir is bisected and ‘cut’ in this model visualization view using an I-slice where the injection wells are located in the center of the reservoir block section to observe the maximum pressure response model results. For each time and year of the model run, two model output plots have been generated. One plot provides the actual model predicted pressure in the reservoir and the second plot provides the change in model predicted pressure relative to the starting date of the simulation (January 2015). Additional plots are provided to identify pressures and conditions in the post-injection period from Years 2045 – 2145.

3.12.1 Present Day January 2015 (Time 0-years)

Figure 3-13 contains model predictions for the initial pressure (2,598 psi) for the Mount Simon Sandstone formation pre-injection, or at Time 0 years.

3.12.2 Future Injection January 2025 – 2045 (Time 10, 30 years)

3.12.2.1 Time 10 Years

Figure 3-14 contains model predictions for the pressure buildup (~3100 psi) for the Mount Simon Sandstone formation during the first 10 years of injection operations, or at Time 10 years. Figure 3-15 represents the delta or change in pressure as a result of injection operations at Time 10 years, ranging from approximately 600 psi at the immediate wellbore area with lateral pressure extent decaying to approximately 300 psi.

3.12.2.2 Time 30 Years

Figure 3-16 contains model predictions for the pressure buildup (~3200 psi) for the Mount Simon Sandstone formation during the first 30 years of injection operations, or at Time 30 years. Figure 3-17 represents the delta or change in pressure as a result of injection operations at Time 30 years, ranging from approximately 650-700 psi at the immediate wellbore area with lateral pressure extent decaying to approximately 500 psi.

3.12.3 Post-Injection Period 2045- 55 (Time 40)

3.12.3.1 Time 40 Years

Figure 3-18 contains model predictions for the pressure buildup (~2900 psi) for the Mount Simon Sandstone formation following 10-years after the first 30 years of injection operations, or at Time 40 years. Figure 3-19 represents the delta or change in pressure as a result of post-injection operations 10 years following a 30-year injection cycle, therefore, at Time 40 years, pressures range from approximately 200-250 psi at the immediate wellbore area, with lateral extent decaying to approximately 150 psi.

3.13 Model Predicted Plume Migration

As CO_2 is injected into the formation a plume develops and the areal extent must be estimated both during the injection period and for a specified period (in this case 100 years were modeled) following the injection period. The extent will be largely dependent on the distribution of porosity and permeability in the model based on the property propagation described previously. As each model layer is given constant properties for both permeability and porosity it is expected that this model will be optimistic in the predicted injection volumes. However, without additional site specific information, this is the best conservative estimate that can be obtained.

Figure 3-20 is a graph of the areal extent of the plume size through time, and indicates that up to 19 square miles is forecast surrounding the injection wells in the up-dip direction. Figure 3-21 represents a map view of the Time 10 and 30 year plume extents change with time. Additionally, the plumes drift after the 30-year injection life and diffuse and disperse in lateral extent with additional plots shown representing Time 50, 100, and 130 year migrated plume extents surrounding the injection wellbores.

Figures 3-22 through 3-25 show the development of the CO_2 plume through time in both three-dimensional view and cross-sectional view from 10 through 30-years of injection. Note that the plume size does not change significantly with time after CO_2 injection is stopped.

3.13.1 Future Injection January 2025 – 2045 (Time 10 and 30 years)

3.13.1.1 Time 10 Years

Figure 3-22 contains model predictions for plume extent in a three-dimensional view for the Mount Simon Sandstone formation during the first 10 years of injection operations, or at Time 10 years. The plume extent around each well area is approximately 2-mile radius, with an overall extent of 6.4 miles. Figure 3-23 represents a cross-sectional view of the plume as a result of injection operations at Time 10 years, showing the injectate as localized within the lower one-third section of the Mount Simon injection unit.

3.13.1.2 Time 30 Years

Figure 3-24 contains model predictions for plume extent in a three-dimensional view for the Mount Simon Sandstone formation during the first 30 years of injection operations, or at Time 30 years. The plume extent around each well area is approximately 2.8-mile radius, with an overall extent of

7.9 miles. Figure 3-25 represents a cross-sectional view of the plume as a result of injection operations at Time 30 years, showing the injectate as localized within the lower one-half portion of the Mount Simon Sandstone.

3.13.2 Post-Injection Period 2055 (Time 40-years)

3.13.2.1 Time 40 Years

Figure 3-26 contains model predictions for plume extent in a 3D view for the Mount Simon Sandstone formation following 10-years after the first 30 years of injection operations, or at Time 40 years. The plume extent around each well area is approximately 2.5-mile radius, with an overall extent of 8.2 miles. Figure 3-27 represents a cross-sectional view of the plume as a result of post-injection operations 10 years following a 30-year injection cycle, therefore, at Time 40 years, showing the injectate as localized within the lower one-half portion of the Mount Simon Sandstone.

3.14 Fracture Gradient Sensitivity

A conservative fracture gradient of 0.65 psi/ft was used for the Base Case Model run in this study (Figures 2-32). Sensitivity to this parameter was investigated using a low and high range of fracture gradients of 0.57 psi/ft (Figures 2-30, 2-31) and 0.8 psi/ft (Figures 2-28, 2-29) to see the model response. As expected, the 0.8 psi/ft case reached the maximum injection load faster than the Base Case (Figure 3-28 and 3-29).

If the fracture gradient is reduced to 0.57 psi/ft the reservoir is not able to handle the full load due to interference between the wells. The Center well cannot take its share of the injected CO_2. A case was run opening up the upper perforation zone in the Center well (Figure 2-33). This helped add more injectivity, but the well still could not meet the target design rate (Figures 3-34 through 3-35).

3.15 Two-Well and Three-Well Model Cases

A Two-Well Model Case was run to simulate the use of only the TEC #1-injection well and the Center well (TEC #2-injection well) to see if the flow system had the capacity to handle the full injection volume and load if one of the wells went off-line. In this Two-Well Model Case the two wells were able to inject the full 239 lb/s injection load once they reached the full injection rate. The time period that it takes to reach the maximum load was extended and increased by using only two wells, and even if a scenario is present if one well goes down after maximum capacity is reached, the model predicts that the two remaining wells will be able to take the full load. Injection rate and pressure profiles are shown in Figures 3-36 and 3-37. A Three-Well Model Case was also simulated using all available TEC injections, and a fracture gradient of 0.65 psi/foot. The wells were under group control and results show the use of three wells can manage the site's injectate in tons per day and over the projected life of the facility (Figure 3-36a).

3.16 Permeability and Porosity Cases

The model was populated with porosity and permeability based upon an analog well. Although this well should be representative of the geology in this formation, a sensitivity study was conducted varying the permeability to see the model response (see Figures 3-38, 3-39). Permeability reductions of 10 %, 50 % and 75 % were simulated and compared with the Base case (Figure 3-38). Permeability was increased by 10 % and the 0.57 psi/ft fracture gradient was used but the Center well was still unable to take its full injection load although it did perform much better. Figure 3-38 shows field cumulative injection for the Base case and permeability sensitivities.

Porosity was reduced by 20 % but the model response was not significantly affected. Figure 3-39 shows field cumulative injection for the 20 % reduction in porosity case.

3.17 Summary of Model Results

A number of scenarios were investigated to try and quantify the controls on injection rates and plume migration within the target storage reservoir. The fracture gradient used has the most significant effect on the ability of the reservoir to meet its expected target rates. A detailed frac gradient calculation will be provided upon collecting of cores, well logs and data from TEC #1-injection well.

Permeability reductions can have significant effect on the reservoirs capacity to meet its target rate. The model was populated with data based on one analog well. This meant that the porosity and permeability properties are constant in each layer. Data from the TEC #1-injection well will be used to address this uncertainty.

The pressure response of the model to injection is contained within the model area. The pressure increases during injection but falls to nearly initial pressure during the 100 year recovery period.

A case incorporating a fourth well two miles to the north of INJ3 was run using the same controls as in the Base Case. Flow of CO_2 was distributed evenly among the four wells.

The field injection and cumulative injection rates for a four well case is shown in the Area of Review and Corrective Action Plan Figures 1, 2, and 3. Figure 4 shows the injection and pressure profile during the simulation period for the various four well cases. Figure 5 shows the plume boundaries as it develops.

3.18 Post-Well Drilling Model Update

Once the TEC #1-injection well is drilled, logged, cored and constructed, additional comprehensive and specific details regarding the geology, and reservoir and seismic will be collected, integrated into the new well plan, providing specific model input parameters.

3.19 PIPESIM Integrated Model

3.19.1 Model Description

PIPESIM 2009 is a steady-state, multiphase flow simulator used for the design and diagnostic analysis of oil and gas production systems and injection. The software tools can model multiphase flow from the reservoir to the wellhead. In addition, it can also analyze flowline and surface facility performance to generate comprehensive production system analysis.

3.19.2 PIPESIM Simulations

PIPESIM was used to design the injection network and choose the size of the injection wells. PIPESIM was used to simulate the various scenarios to choose the maximum number of wells needed to inject 239 lbs/s of CO_2 without exceeding 2,200 psia at the compressor.

The gas composition, compressor operating pressure and temperature were provided by CCG. Resolution of the distances between the wells, operating scenarios, and the internal diameters of the surface pipelines were developed through an iterative process using the simulations as a basis for discussion. The geothermal gradient, trajectory and depths of the wells were provided by the reservoir group.

Simulations were carried out based on above mentioned information with various other parameters which are discussed below such as composition, tubing internal diameter etc.

The simulation investigated two different injectate fluid compositions, pure CO_2, and impurities of H_2, CO, N_2, CH_3OH, and Ar.

- Pure (100%) CO_2 and; the other composition was specified
- 98.38 mol% CO_2, 0.61 mol% H_2, 0.56 mol% CO, 0.36 mol% N_2, 0.07 mol% CH_3OH, and 0.01 mol% AR.

Not all of the components of this mixture were used to calculate the fluid properties input into PIPESIM. The composition used for property modeling consisted of 98.38 mol% CO_2, 0.61 mol% H_2, and 0.56 mol% CO normalized to one. The property modeling was conducted using NIST Reference Fluid Thermodynamic and Transport Properties Database (REFPROP): Version 8.0. CH_3OH was left out of the modeling because the equations of state for the mixtures in REFPROP are not able to handle that component as part of a mixture. The tubing sizes used in the simulations were 5.5-inch (ID=4.89 inches) and 7-inch (ID = 6.184 inches).

The initial simulations for each mixture are described further in Table 3-2. Note the erosional velocity values are rather high due to the C value being very conservative.

Table 3-2
Initial Injection Network Simulations and Cases in PIPESIM

Injectate Composition	5.5-inch Casing: 3 vertical wells	7-Inch casing: 2 vertical wells
Pure CO_2	1. BHP (injection pressures) of 3400 psia a. Maintaining erosional velocity ratio <1 2. With equal injection rates between wells. a. Maintaining erosional velocity ratio <1	5. BHP (injection pressures) of 3800 psia a. Maintaining erosional velocity ratio <1 6. With equal injection rates between wells. a. Maintaining erosional velocity ratio <1
98.38% CO_2 Mixture	3. BHP (injection pressures) of 3400 psia a. Maintaining erosional velocity ratio <1 4. With equal injection rates between wells. a. Maintaining erosional velocity ratio <1	7. BHP (injection pressures) of 3800 psia a. Maintaining erosional velocity ratio <1 8. With equal injection rates between wells. a. Maintaining erosional velocity ratio <1

The networks were modeled using a single source with a linear pipeline connecting the injection wells in series. Figure 3-40 shows the modeled pipeline networks and the associated injection wells. After the initial simulations of Model Runs 1 through 8 were completed (Figures 3-41 through 3-45), 5 additional simulations were conducted using a network with 3 wells with 7-inch tubing (Figure 3-46 through 3-49). In this simulation the pipelines branch as specified and shown in Table 3-3.

Table 3-3

Pipeline Simulations Used for the Network Shown

Pipeline Branch	Distance (miles)	Pipeline ID (inches)	Pipeline ID (inches)
B1	0.75	14.75	16
B2	2	12	12.75
B3	2	12	12.75

3.19.3 Results

The first eight cases presented in Table 3-2 were modeled and the results are summarized in Table 3-4. Only four of the eight cases modeled met the criterion of the erosional velocity ratio being less that one. Table 3-5 provides the results of the PIPESIM modeling. Note: Shading indicates erosional velocity ratio >1. This scenario is not viable as it will compromise the integrity of the tubing.

3.19.4 PIPESIM Model Parameters

Construction of a surface network model is critical to account for constraints imposed on the surface model such as erosional velocity in the pipes and constraints on the subsurface reservoir model such as fracture pressure of the formation. In addition, the network must be able to supply a minimum flow capacity of 858,680 lb/hr with 3.42 million metric tons of CO_2 per year minimum at a maximum 2,220 psi at the outlet of the compressor.

The PIPESIM model built for this project has the following structure. A 16-inch OD (14.75-inch ID) and 12.75-inch OD (12-inch ID) pipeline was used for the surface pipeline and 7-inch OD tubing (6.184-in ID) was used for each of the three wells. The compressor (source) is located 1 mile from the first well (TEC #1-injection well in the simulation model) and the three wells are spaced 2 miles apart. A schematic diagram of the flow system is shown in Figures 3-40 and 3-41.

The maximum pressure at the source was held at a constant 2,220 psi and several simulations were run using different flow rates and THP. The corresponding BHP) (at 6932.5 ft TVD) were calculated based on these flow rates and THPs. The PIPESIM model was broken into 6 segments, Source to B1, B1 to B2, B2 to B3 and each node through its corresponding well to the reservoir. The vertical flow profiles (VFP) corresponding to each segment were exported as VFP tables for input into the simulator. In this way, the maximum compressor pressure level of 2,220-psi can be used by the simulator to determine the maximum THPs of the wells. Figure 3-41 shows a visualization of the coupled flow system. This model is used to determine if the flow network is capable of handling the injection rate with the minimum number of wells possible.

Based on the calculated surface network and well BHPs calculated in the PIPESIM model, the phase diagram in Figure 3-42 shows the state of the CO_2 in various parts of the system. The CO_2 starts as a supercritical fluid at the pipeline inlet. At the surface location of TEC #3-injection well it turns to liquid. At this terminus, when arriving in the downhole environment, at the reservoir formation, it is heated up to become a supercritical fluid once again.

One limitation of this method is that for CO_2 injection wells when the rate changes so, in turn, does the temperature at the outlet pipe which affects the inlet temperature of the pipe immediately off of it and thus the well head temperature (WHT) of the wells. Although not an easy task, the PIPESIM model can be directly coupled with the ECLIPSE simulator to account for these temperature differences. This can be a time consuming process and may result in a model with unreasonable simulation times.

The temperatures used in the creation of the VFP tables are listed in Table 3-4.

Table 3-4
The PIPESIM nodes and associated temperatures used in the model.

Node	Temperature, degF
B1	120
B2	108
W1	108
B3	95.5
W2	95.5
W3	73.3

The pressure versus temperature plots for each of the cases is provided below. All of the plots show a phase diagram for pure CO_2 and the CO_2-H_2-CO-mixture CO_2=98.38%, H_2=0.61% and

CO=0.56%) Each plot shows all branches in the network from the source starting at B1 to the bottom of each individual well (W1, W2, and, if present, W3). The source temperature was provided as 120° F. The results of the 5 cases run using 3 injection wells with 7-inch tubing are provided in Table 3-6. Of the 5 Model Cases run, only 4 cases had BHPs greater than the expected injection formation ambient pressure. All of the 3-injection well, and 7-inch tubing Model Cases simulations met the erosional velocity ration criterion.

3.19.5 Conclusions Based on PIPESIM Modeling

Based on the results of these simulations the following conclusions can be made:

- The Injection rates have to be controlled at each well for both fluid composition scenarios and tubing sizes to meet and/or maintain an erosional velocity ratio less than one.
- All 7-inch tubing scenarios using three injection wells met the erosional velocity ration criterion with erosional velocity ratios less than one.
- For 5.5-inch tubing the maximum injection rate per well permissible, in order not exceed the erosional velocity of one is 84 lbms/s.
- It may be advisable to have 4 injection wells, if a design using 5.5-inch tubing is used. This would also compensate and maintain operational efficiency if 1 well is off-line due to maintenance and/or work-over.
- The pressure versus temperature plots show that the fluid stays in single phase throughout the network.
- In some cases the temperatures at the well head are below critical temperatures for pure CO_2 and CO_2-H_2-CO mixture. The well head pressures are above the critical pressures, and at the injection point they are above the critical temperatures and pressures.
- Simulations should be carried out for varying source temperatures including the minimum and maximum source temperatures expected.

4.0 INJECTION WELL DESIGN AND CONSTRUCTION

4.1 Introduction

The TEC #1 injection well will be used as a test well to evaluate the Mount Simon Sandstone formation for CO_2 sequestration capacity and as a Class VI CO_2 injection well. The well is designed as a vertically drilled well to a proposed total depth (TD) of +/- 7,200 feet (KB-below kelly bushing).

A full formation evaluation program will include mud logging during drilling to evaluate all formations penetrated real-time, acquiring full conventional whole cores, sidewall cores (optional) in both confining and potential injection formations; and performing specialized openhole electric logging. The casing weights and grades as outlined represent the minimum specifications for well construction, with potential that even more robust grades and heavier weights may be used if needed.

4.2 Injection Well Construction Overview

As an optional design consideration for hole stability, a 36-inch hole may be drilled from surface to a depth of approximately 45-60 feet KB. A 30-inch diameter conductor pipe would then be cemented back to surface. A 26-inch borehole will be drilled through the glacial till, considered to be the lowermost USDW in the area, to at least 100 feet below the base of the till. An approximate maximum depth of 400 feet is assumed for the well design but will be adjusted based on actual field conditions. Openhole wireline logs will be run in the section. This borehole will be through the 30-inch conductor (if present) or from ground surface. A 20-inch surface casing will be run and cement circulated back to surface US EPA will be notified of placement and cementing of the surface casing and will be notified of the well construction and may witness any parts of the project at their discretion.

The lowermost USDW (defined as <10,000 mg/l) is located at approximately 125 feet BRT. The 20-inch surface casing with its continuous cement sheath will fully isolate the lowermost USDW from the next stage of the borehole. A 17-1/2-inch borehole will be drilled into the Eau Claire formation whose top is expected a depth of 5,115 feet KB and to a depth of approximately 5,400 feet KB, where openhole logs will be run. Next, 13-3/8-inch casing will be run to total depth for this section and cemented back to surface. US EPA will be notified to witness placement and cementing of the surface casing.

A 12-1/4-inch borehole will then be drilled from current total depth to a projected total depth of approximately 7,200 feet through the Mount Simon Sandstone into the pre-Cambrian, where a suite of openhole logs will be run. A set of 3 conventional whole cores is planned: one 30-foot core in the Eau Claire formation consisting of conventional 4-inch core, and two 30-foot cores are planned in the Mount Simon Sandstone injection interval. Additional supplemental horizontal rotary cores may be taken depending on borehole conditions if coverage is required.

An openhole logging suite will be performed to evaluate the reservoir intervals, thickness, quality, porosity and permeability in the Mount Simon Sandstone injection interval. Detailed information on the Eau Claire will also be collected and integrated into the reservoir model as confining formation parameters.

After logging a decision will be made to run and set the 9-5/8-inch casing string either completely through the Mount Simon interval or configure the well as an open hole completion with a shorter length of 9-5/8-inch casing. The dynamic (reservoir) modeling results are affected by whether the holes are completed with perforated casing versus open-hole. The reservoir models will be updated based on the results obtained from the initial injection (characterization) well installation. Injection scenarios will be optimized and would be expected to evaluate a combination of open hole and cased hole completion.

4.2.1 Well Construction Information

The maximum proposed well total depth (TD) is planned for approximately 7,200 feet KB. This total depth is expected to be present in the pre-Cambrian rocks situated below the base of the Mount Simon Sandstone, which would allow sufficient rat hole for wireline logging and testing purposes. A table of the expected depths and sequence of specific geological formations that will be penetrated and encountered by the TEC #1-injection well follows below:

Table 4-1

Expected Depths for Key Formations at TEC Site

Formation	Expected Depth (GL- ft)	Expected Depth (KB) - ft	Estimated Thickness ft	Lithology	Comments
Ground Level	0	15			substructure
Soil/Overburden	50	190	140	Glacial till	USDW
New Albany	**1830**	**1845**	**120**	**shale**	**Sealing unit**
Maquoketa	**2560**	**2575**	**525**	**shale**	**Secondary seal**
Trenton Black River				limestone	
Dutch Town				dol-ls	
St Peter	3100	3115	200	qtz arenite	Observation Interval
Knox	3400	3415		dolomite	low porosity intervals
Eau Claire	**5115**	**5130**	**215**	**sh/ss/ls/dol**	**Primary Sealing unit**
Mount Simon	**5615**	**5630**	**1300**	**sandstone**	**Injection Interval**
Precambrian	6915	6930	285	Granite/ Granite wash	Igneous/clastic sedim
Total Depth	7200	7215			

Proposed Injection Interval

Overlying Confining Seals

4.2.2 Well Casing Specifications

Prior to initiating drilling activities, 30-inch conductor pipe may be set to 45-60 feet KB using a rat hole service or small air rig and cemented in place. The conductor pipe would be installed if it is determined to be needed for hole stability. A 26-inch surface hole will be drilled to a depth of at least 100 feet below the lowermost USDW (estimated at 125 feet KB). For permitting purposes, a maximum depth of approximately 400 feet KB is assumed for the surface casing and is considered as the nominal depth in the remainder of the well design. At that point, 20-inch surface casing will be run and cement circulated to surface. The 17-1/2-inch intermediate hole will be drilled into the Eau Claire formation to approximately 5,400 feet KB and then 13-3/8-inch intermediate casing will be run to current total depth and cemented to surface. For the production portion of the well, a 12-1/4-inch borehole will be drilled through the Mount Simon Sandstone injection formation to a total depth of approximately 7,200 feet. A production string of 9-5/8-inch casing may be set through the entire Mount Simon Sandstone interval, or the well may be completed open hole based on the reservoir properties encountered from testing and evaluation.

The casing design summary is shown below:

Table 4-2

Injection Well Casing Design Summary

Borehole Size	**Casing Size (OD)**	**Estimated Setting Depth**	**Design FIT Value**	**Casing Seat Justification**
Inches	**Inches**	**KB Ft**	**Equiv. MW Ppg**	
36	30	60 +/-	N/A	Structural Support. Prevent surface washout.
26	20	400 +/-	N/A	Seal off potential troublesome glacial till and provide a good casing seat for kick tolerance. Engineered oilfield practice.
17-1/2	13-3/8	5,400 +/-	9.3 – 9.6	Seal off the St. Peter and shales, offer protection for longer lasting carbon dioxide injection.
12-1/4	9-5/8	7,200 +/-	9.4 – 9.9	Total depth below Mount Simon. Option for openhole completion and/or use of Chrome 13.

The proposed casing specifications for the TEC #1-well are shown in the table below:

Table 4-3

Minimum Injection Well Casing Specifications

Tubular	Approx. Depth	Size OD/ID	Weight	Grade	Conn. Type and OD	Collapse/Burst	Body YS	Thermal Conductivity
	KB Ft	Inches	Lb/ft		OD inches	Psi	Lbs x 1000	BTU/Ft.hr. °f
Conductor	60 +/-	30						
Surface	400 +/-	20/19.124	94	H-40	STC (21)	520 / 2,110	1077	29.02
Intermediate	5,400 +/-	13-3/8/12.515 13-3/8/12.415	61 68	J-55 J-55	STC or LTC STC or LTC (14.375)	1,540 / 3,090 1,950 / 3,450	962 1,069	29.02 29.02
Production	7,200 +/-	9-5/8/8.835	40 or 47 or 13CR (47)	N-80 or L-80 or CR80	LTC or STC 3SB (10.625)	3,090 / 5,750 4,760 / 6,870 4,760 / 6,870	916 1086 1086	29.02 29.02 14.86
Tubing	5,300 +/-	7	26	N80 or better	Atlas Bradford ST-L or stronger (7)	5,410 / 7,240	604	29.02

Note: The casing weights and grades as outlined are the minimum specification, higher grades and heavier weights may be used if needed. The tubing may be reduced to 5.5-inch diameter depending on actual site conditions and revised injection and reservoir modeling)

4.2.3 Well Casing Design Considerations

The following considerations were derived from a review and knowledge base of offset wells drilled in the central Illinois Basin, and ISGS geological interpretations for incorporation and refinement of the well design and casing program:

- Potentially serious loss circulation problems in the Potosi section of the Knox formation.
- An apparently normal pressure regime for all wells reviewed and through peer reviews conducted with personnel that have drilled wells in the Illinois Basin (0.433 – 0.445 psi/ft).
- A review of primarily all oil wells and gas storage wells drilled in the northern portion of the basin.
- The Mount Simon Sandstone is a thick and heterogeneous formation expected to range from 1,100 – 1,300 feet of gross thickness. (Note: this thickness will be determined upon review of the data and logs and cores from the TEC # 1).
- Several wells penetrating the shales above the Eau Claire have reported some borehole instability across these shale sections. To counter this, the well will be drilled with low solids, non-dispersed water base drilling fluid.

4.2.4 Well Casing Design Standards

Standards utilized for casing and drilling are as follows:

- All surface, intermediate and production casing will be pressure tested prior to drilling out the shoe track or perforating. Subsequently, such tests will be repeated whenever the integrity of the casing is in doubt (long rotating hours, high dogleg severity, etc.). A pressure test will be conducted on the production casing/liner prior to running the completion.
- Well control will be maintained while running casing through maintenance of borehole fluid column, barriers, and surface well control systems.
- The casing installed in any well shall be designed to withstand burst, collapse, tension, bending, buckling or other stress that are known to exist or that may reasonably be expected to exist.

- The performance properties of any casing shall be considered to be those listed for that casing in the American Petroleum Institute's (API) Bulletin on Performance Properties of Casing, Tubing, and Drill Pipe, API BUL 5C2, nineteenth edition, October 1984.

- The cementing plan will be based on a rigorous design program that is based on available data such as hole directional and deviation surveys (see Section 4.11) and caliper logs. Centralizers will be utilized to ensure that casing centralization is achieved.

4.2.5 Minimum Design Factors

Table 4-4

Minimum Design Factors

Design Loads	**Surface/Intermediate Casing, Drilling Liners**	**Production Casing Liners**	**Tubing**
Collapse	1.0	1.1	1.125
Burst:			
Normal Service	1.1	1.1	1.1
Critical Service	1.25	1.25	1.25
Tension:			
Pipe Body	1.3	1.3	1.3
Connection	1.5	1.5	1.3
Compression	1.3	1.3	
Triaxial	1.25	1.25	1,25

- The casing installed in any well shall be designed to withstand collapse loading based on the following assumption:

    1. The hydrostatic head of the drilling fluid in which the casing is run acts on the exterior of the casing at any given depth;
    2. Subject to the casing is 1/3 evacuated;
    3. The production casing is completely evacuated.
    4. The effect of axial stresses on collapse resistance shall be taken into account.
    5. The effect of temperature deration and casing wear shall be taken into account.

- Any casing/liner that creates an annular space with the production tubing shall be treated as a production casing/liner.

- The casing installed in any well shall be designed to withstand tensile loading based on the following assumptions:
    1. The weight of casing is its weight in air, and,
    2. The tensile strength of the casing is the yield strength of the casing wall or of the joint, whichever is the lesser.

4.2.6 Casing Design Assumptions

The following assumptions were made during the design process for the TEC #1-Injection well at Taylorville:

- A 5% casing wear due to Bottomhole Assembly (BHA) rotation is assumed on all casing design segments with consecutive hole sections.
- Wall tolerance of 87.5 % is assumed as per API standards.
- Temperature deration is taken into account on the design of the 13-3/8-inch and 9-5/8-inch casing strings.
- The 13-3/8-inch casing is being proposed and engineered to be required to comply with a casing design standard (IPM-WELL-S029) to pass a 1/3 evacuation loading on collapse (This standard is well above the standard as utilized in normal oil and gas applications, and best practices and engineering disciplines).
- The 9-5/8-inch casing string will have to pass a calculated evacuation loading to approximately 3500 feet. (The 9-5/8-inch long string casing will be cemented into the 13-3/8-inch casing for extra protection and to preserve the integrity of the long range goals of injecting supercritical, liquid CO_2).
- The casing is designed to offer the most cost effective, engineering-wise acceptable option to the project, designed to preserve the integrity of the operation for the life of the commercial TEC project. In the event that the casing recommended is not available, final casing selection would be based on what other technical options are currently available and what might in stock in US-based tubular suppliers inventory. The minimum criteria for an alternate design would be to exceed standard design criteria.

4.2.7 Casing Design Models

Table 4-5
Casing Design Models

13-3/8-inch Intermediate Casing

Load Case	**Pressure**	**Profile**	**Temp**	**Wear**	**Minimum**	**Design**	**Factor**	
	Internal	**External**	**Profile#**	**%**	**Burst**	**Collapse**	**Tension**	**Triaxial**
Axial weight in air								
Axial running load 5 ft/s								
Burst	2730 psi	PP	Drilling		> 100	3.98	> 100	6.65
Pressure Test	1500 psi	PP	Drilling		> 100	3.98	> 100	6.65
Collapse	1/3 Evac.	Drilling Fluid	Drilling		> 100	3.98	> 100	6.65
As Cemented	9.2 ppg Mud	Cement	Cementing		> 100	3.98	> 100	6.65

9-5/8-inch Production Casing

Load Case	**Pressure**	**Profile**	**Temp**	**Wear**	**Minimum**	**Design**	**Factor**	
	Internal	**External**	**Profile#**	**%**	**Burst**	**Collapse**	**Tension**	**Triaxial**
Axial weight in air								
Axial running load 5 ft/s								
Burst	Tubing leak – static	PP	Drilling	5	2.03	1.09	3.55	1.64
Pressure Test	2700 psi	PP	Drilling	5	2.03	1.09	3.55	1.64
Tubing Leak-static	Reservoir Pressure Gas grad.	PP	Production	5	> 2.03	1.09	3.55	1.64
Collapse	100% Evac.	10.5 ppg mud (max)	Drilling	5	> 2.03	1.09	3.55	1.64
Cementing and Landing	9.2 ppg mud	Cement to next string or surface	Cementing	5	> 2.03	1.09	3.55	1.64
Full Evacuation	Gas grad.	10.5 ppg mud (max)	Drilling	5	> 2.03	1.09	3.55	1.64

Design temperature profile (Undisturbed, Drilling, Cementing, WOC, Production)

4.2.8 Casing Design Envelope

Casing	Design Pressure Test (psi)	Design KT in next hole section
13-3/8-inch	1350	25 bbls with 0.5 ppg kick intensity
9-5/8-inch	2700	25 bbls with 0.5 ppg kick intensity

- The kick tolerance (KT) for the 13-3/8-inch and 9-5/8-inch casing strings will comply with the minimum design standards.

The KT and Maximum Allowable Surface Pressure (MASP) are calculated as follows in the example below:

For 13-3/8-inch Casing

Assumes: EMV = fracture equivalent mud weight (EMV) of 13 ppg
TVD = 1000 feet;
MW = 9.2 ppg mud weight
25 bbl kick (or inflow)

MASP = 0.052 x (EMV – MW) x TVD = 0.052 x (13 – 9.2) x 1000 = 197 psi	KT = (MASP – (MW x 0.052 x H))/0.052/TVD = (197 – (9.2 x 0.052 x 100) / 0.052 /1000 = 3.09 ppg

For 9-5/8-inch Casing

Assumes: FIT EMV = formation integrity test -- equivalent mud weight (EMV) of 12 ppg
TVD = 7000 feet;
MW = 10.5 ppg mud weight
25 bbl kick (or inflow)

MASP = 0.052 x (EMV – MW) x TVD = 0.052 x (12 – 10.5) x 7000 = 546 psi	KT = (MASP – (MW x 0.052 x H))/0.052/TVD = (546 – (10.5 x 0.052 x 171) / 0.052 /7000 = 1.24 ppg

4.2.9 Well Construction Schematic

A well design schematic of the proposed TEC #1-injection well has been prepared and depicts the drilled borehole and casing sizes, with depths, as well as the location of the Mount Simon Sandstone injection interval (see Figure 4-1 for TEC #1-injection well completion design and Figure 4-2 for proposed preliminary plug and abandonment design).

4.3 Casing Program for Site Wells

Depending on final results of drilling, installation, and testing of the first well, TEC #1-injection well, the remaining 2-3 wells within the land area identified in the Permit application will be constructed in a similar manner to the first well.

A 36-inch (or larger) borehole with a section of 30-inch conductor casing may be set to a depth of +/-45-60 feet in the shallow well area to offer integrity and stability to the surface borehole. A 26-inch surface borehole will be drilled to a depth of approximately 400 feet KB, depending on the base of the glacial till. At that point, 20-inch diameter surface casing will be set and cemented to surface to isolate all local USDWs. A 17-1/2-inch borehole will be drilled from 400 feet to a total depth of approximately 5,400 feet KB and 13-3/8-inch protection casing will be set and cemented from this section of total depth to surface. The casing shoe will be set in the Eau Claire confining horizon which is expected to be a low permeability seal overlying the injection interval. The Mount Simon Sandstone injection interval will then be drilled using a 12-1/4-inch borehole to a depth of approximately 7,200 feet. Expectations are that the primary Mount Simon Sandstone injection interval is present within a range of 5,615 to 6,915 feet. Upon total depth and assessment of the injection interval and considerations from data and testing of the first TEC #1-injection well, a decision will be made to complete the wells with 9-5/8-inch casing set to a total depth of approximately 6,300 feet. The casing will be N-80 or L-80 or better from surface down to near the top of the Mt. Simon formation. The lowermost 200 to 300 feet of casing will be CR80 (Grade 13 Cr) casing will be employed in the lower borehole section where the injection packer will be set above the Mount Simon Sandstone formation top (~5,300-5,600 feet). A metallurgically compatible cross-over will be used to connect the CR-80 and carbon steel casing section. The final depths and lengths of each casing will be based on field conditions and final design considerations derived from the field data and updated reservoir modeling results (See Figure 4-1). If this design is followed, the 9-5/8-inch casing will be cemented from the casing shoe back to ground surface and cement will be present and overlap between the 13-3/8-inch casing annulus and 9-5/8-inch casing annulus sections. It may be necessary to cement the 9-5/8-inch casing in at least two stages. The casing will be cemented back to surface. Centralizers will be used as needed in the intermediate and deep sections of the injection wells, based on the hole directional and deviation surveys (see Section 4.11).

Based on preliminary design, the injection tubing will be 7-inch 26lb API grade 80,000psi or better. The maximum allowable based on joint strength for 7-inch 26lb N80 or L80 tubing (the minimum tubing that may be used) is 357,760 lbf assuming an Atlas Bradford ST-L joint. The connection used will be a flush connection that has the joint strength of an Altas Bradford STL joint or better.

The weight of the tubing in air assuming 6732 ft of 7-inch 26lb tubing is 175,032 lbf. This provides a safety margin at the top joint slightly over two if one assumes the axial load is only being carried by that joint. The tubing size could be reduced based on actual site conditions and the results of injection and reservoir modeling. If smaller tubing were to be utilized (e.g. 5.5-inch diameter) a complete engineering analysis would be completed to verify compatibility and strength requirements for injection.

All casing strings and the overall well design configuration are designed for the life of the TEC facility, assuming 35+ years of well life. The proposed casing specifications for the additional site injection wells, TEC # 2, # 3, and # 4-injection wells are shown in the table below:

Table 4-6
Proposed Casing Program for TEC Injection Well Nos. 2, 3, and 4

Tubular	**Setting Depth**	**Borehole Size**	**Casing Size**	**Weight**	**Grade**	**Conn.**	**Collapse/Burst**	**Body YS**
	KB Ft	**Inches**	**Inches**	**Lb/ft**			**psi**	**Lbs x 1000**
Conductor	60 +/-	36	30					
Surface	400 +/-	26	20	94	H-40	STC	520 / 2,110	1077
Intermediate	5,400 +/-	17-1/2	13-3/8	61 68	J-55 J-55	STC STC	1,540 / 3,090 1,950 / 3,450	962 1,069
Production	7,200	12-1/4	9-5/8	40 or 47 or 13CR (47)	N-80 or L-80 or CR80	LTC or STC 3SB	3,090 / 5,750 4,760 / 6,870 4,760 / 6,870	916 1086 1086

4.3.1 Openhole Completion

Following drilling of the initial well, TEC may adjust the completion on TEC Nos. 2, 3, and 4 injection wells to use open-hole completion methods across the Mount Simon injection interval (if warranted by reservoir data, geologic information). For larger fluid volume management, this approach is superior, and will enhance injectivity in the interval, while also allowing for minimal formation damage from cement invasion, and reducing friction loss across a long section of cased hole, which has been cemented and perforated in the Mount Simon Sandstone injection interval. The openhole method allows for greater volumes of fluid to be received by the formation with a net benefit of reducing operating pressure.

4.3.2 Deep and Shallow Observation Well Schematics

As part of the commitment to a comprehensive site Monitoring Program, TEC has plans to site, construct and complete a series of observation wells to the USDW in the area surrounding the plant site. Preliminary design and well schematic for the shallow glacial till wells have been prepared and included as Figures 4-3 respectively.

4.3.2.1 In-Zone Observation Well

Two in-zone pressure observation wells are proposed. One may be located just outside the AOR in an up-dip direction. The other may be located between the maximum projected extent of the CO_2 and the Town of Taylorville, IL. Final locations will be determined following the AOR re-evaluation (after installation of TEC #1). See the Testing and Monitoring Plan for more details on the in-zone well design.

4.3.2.2 Shallow Groundwater Observation Wells

Plans for a set of shallow groundwater observation wells have been included in the site Monitoring Program (see Testing and Monitoring Plan), and include up to 3 shallow groundwater wells drilled to the base of the glacial sediments. This plan may be amended if it is determined during installation of the surface casing for the injection wells that the freshwater zone extends into bedrock. It is anticipated that these wells would be set at approximately 125 feet KB and would not exceed a maximum depth of 300 feet. Based on available information, the glacial till includes the lowermost USDW in the area. Figure 4-4 provides a preliminary well design and schematic for these shallow groundwater wells, while Figure 4-4a contains a detailed surface design and subsurface completion specifications. Specific well locations, interval depths, and well design will be provided following drilling of TEC #1-injection well and subsequent data integration and evaluation, Testing of the shallow glacial till freshwater aquifer fluids will occur using a downhole pump and a set frequency for fluid sample recovery and analysis. The Testing and Monitoring Plan will be updated as part of a permit amendment following drilling and evaluation of the initial injection well.

4.4 Well Drilling Program

A general program for drilling TEC #1-injection well will be performed utilizing best engineering practices and knowledge from drilling Mount Simon Sandstone, while using Class VI injection well standards. If there are design changes based on site conditions, TEC will prepare a revised well prognosis and well design and submit to US EPA for review and concurrence.

Upon final US EPA permit approval and authorization, the well will be drilled to the pre-Cambrian at an estimated total depth of approximately 7,200 feet. TEC #1-injection well will be tested extensively via openhole logging, formation fluid sampling, salinity measurements, whole and rotary coring and rock mechanics testing to determine frac gradient and confirm operating constraints. Injectivity testing may be performed using KCl fluid or other suitable brine to confirm reservoir capability and storage capacity. The accumulated data set of geologic, reservoir, formation and fluids will be evaluated and provided to US EPA as part of the permit revision process.

4.5 Cementing Program

The following are cementing specifications for the initial TEC #1-injection well. Actual volumes and quantities will depend on site specific borehole conditions and final casing depth settings. Well logs, including CemCade or equivalent will be completed for each borehole section to guide the cementing program.

Table 4-7

Proposed Cementing Program for Injection Wells 1-4

Name	Depth Interval (feet)	Type/ Grade	Additives	Quantity (cubic feet)	Circulated to Surface	Thermal Conduct. BTU (ft.hr.°F)
Surface[1]	0-300	Class A	Accelerator, LCM	~430	Yes	0.73
Intermed.[2]	0-5,000	50:50 LP3:Class A	extender, antifoam, accelerator	~1300 (lead), ~3000 (tail)	Yes	0.54
Long[3]	0-base of long string	DCO_2 (acid gas resistant)	Antifoam, dispersant, fluid loss + antisettling (tail)	~2000 (lead), ~1000 (tail)	Yes	0.75

[1] Surface casing Class A + 2% CaCl2 accelerator + 0.25 lb/sk D130 LCM, Density: 15.6 ppg Yield: 1.20 cf/sk Mix water: 5.23 gal/sk

[2] Intermediate casing Int lead slurry: 50:50 LP3: Class A + 6% D020 extender + 0.2% D046 antifoam + 2.5% S001 accelerator, Density: 13.3 ppg Yield: 1.51 cf/sk Mix water: 7.502 gal/sk;
Followed by tail slurry of: Class A + 0.2% D046 antifoam + 0.5% D065 dispersant + 0.25% D167 fluid loss additive, Density: 15.6 ppg Yield: 1.19 cf/sk Mix water: 5.234 gal/sk

[3] Long string casing Lead slurry: 1 35:65 LP3:Class A + 6% d020 extender + 10% salt BWOW + 0.1% D013 retarder + 0.2% D046 antifoam + 0.2% D065 dispersant + 0.2% D167 fluid loss additive, Density: 12.8 ppg Yield: 1.96 cf/sk Mix water: 10.54 gal/sk; Followed by tail slurry: DC02 Acid-Gas-Resistant Blend + 0.16 gal/sk D080 dispersant + 0.2 gal/sk D168 fluid loss additive + 0.03 gal/sk D175 antifoam + 0.1 % D153 antisettling additive, Density: 15.8 ppg Yield: 1.09 cf/sk Mix water: 3.012 gal/sk

4.5.1 Surface Casing Cementing Program

The following cementing program is proposed for installation of the surface casing string:

- 20-inch casing in a 26-inch borehole at +/- 400 feet KB
- Pump cement to surface
- Estimated borehole volume was calculated using 50 % excess over bit size (gauge hole)
- Actual calculated volume from open-hole caliper log plus 20 % excess

Cement Slurry	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume sacks
Cement Slurry	15.6	1.20	5.23	430

Spacer:

20 bbl of fresh water

Cement Slurry:

Class A Cement + 2% $CaCl_2$ accelerator + 0.25 lb/sack D130 LCM

4.5.2 Intermediate Casing Cementing Program

The following cementing program is proposed for installation of the intermediate casing string:

- 13-3/8-inch casing in 17-1/2-inch borehole at +/- 5,115 feet RKB
- Pump cement to surface
- Estimated borehole volume was calculated using 50 % excess over bit size (gauge hole)
- Actual calculated volume from caliper log plus 20 % excess on the second stage
- Intermediate casing Int lead slurry: Density: 13.3 ppg Yield: 1.51 cf/sk Mix water: 7.502 gal/sk;

Cement Slurry	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume sacks
Lead Cement	13.3	1.51	7.502	1300
Tail Cement	15.6	1.19	5.234	3000

Cement Slurry	Specifications
Spacer:	20 bbl of mud flush spacer 20 bbl fresh water spacer
Lead Cement:	Class A Cement + 6% D020 50:50 LP3:Class A + 6% D020 extender + 0.2% D046 antifoam + 2.5% S001 accelerator,
Tail Cement:	Class A Cement + 0.2% DO46 antifoam Followed by tail slurry of: Class A + 0.2% D046 antifoam + 0.5% D065 dispersant + 0.25% D167 fluid loss additive

4.5.3 Long String (Production) Casing Cementing Program

The following cementing program is proposed for installation of the long string casing:

- 9-5/8-inch casing in 12-1/4-inch borehole at +/- 7,200 feet RKB
- Pump cement to surface
- Estimated borehole volume was calculated using 20 % excess over bit size (gauge hole)
- Actual calculated volume from caliper log plus 20 % excess on the second stage
- DCO_2 Acid-Gas-Resistant Blend Cement
- Intermediate casing Int lead slurry: Density: 13.3 ppg Yield: 1.51 cf/sk Mix water: 7.502 gal/sk;

The production casing cement job will likely be a single stage circulation technique. A casing float shoe will be placed on the bottom of the long string casing and a float collar placed one joint of casing above the bottom. A bottom wiper plug will be used to wipe the mud film from the casing ahead of the cement job. The bottom of the injection zone monitor casing will be set a few feet off the bottom of the hole. The actual cement pumping and displacement rates will be determined using a cement placement simulator and will depend upon well specific parameters such as mud properties and hole size learned during the actual drilling process from the wireline surveys, including a caliper log. The surveys and cement reports will be provided in the well completion report. A custom spacer will be designed based on the final hole conditions and will be pumped ahead of the cement system to assist in mud removal.

Although single stage cement jobs are planned for all casing strings, information learned during the drilling process (e.g. lost drilling returns) and testing of the openhole (e.g. significant features identified via well logs) may lead to a decision to use a two stage cementing technique on any or all of the strings. Should a two-stage cement system be required for the long string, the lower cement stage will cover the Mount Simon and Eau Claire and come up to a few hundred feet above the Eau Claire. A stage cementing tool will be run on the long string casing allowing the second stage or upper section to be cemented after the lower cement stage has reached 500 psi compressive strength. The designed lead system will cover the upper hole section and a small amount of the CO_2 resistant cement tailed in and placed across the stage cementing collar. The stage cementing collar will be drilled out and casing integrity test performed.

Cement Slurry	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume sacks
Lead Cement	12.8	1.96	10.54	2000
Tail Cement	15.8	1.09	3.012	1000

BHCT (Bottomhole Circulating Temperature)	40 degC [104 degF]

Cement Slurry	Specifications
Spacer:	20 bbl of mud flush spacer 20 bbl fresh water spacer
Lead Cement:	Class A Cement + 6% D020 extender 35:65 LP3:Class A + 6% D020 extender + 0.10% salt BWOW+0.1% D013 retarder +0.2% D046 antifoam + 0.2% D065 dispersant + 0.2% D167 fluid loss additive, Density: 12.8 ppg Yield: 1.96 cf/sk Mix water: 10.54 gal/sk;
Tail Cement:	DCO_2 Acid-Gas-Resistant Blend Cement +0.16 gal/sk D080 dispersant + 0.2 gal/sk D168 fluid loss additive + 0.03 gal/sk D175 antifoam + 0.1 % D153 antisettling additive, Density: 15.8 ppg Yield: 1.09 cf/sk Mix water: 3.012 gal/sk

4.5.4 CO_2 Resistant Cement

CO_2 resistant cement will cover the entire open hole section from the base of the long string (well design assumes 400 open hole completion at the bottom of the injection well) and be placed approximately 500 feet back into the 13-3/8-inch casing. Assuming the intermediate casing will be set 50 feet into the Eau Claire, the CO_2 resistant cement will be about 450 ft above the Eau Claire, thus ensuring protection of the caprock from the effects of injected CO_2. The CO_2 resistant cement properties are provided below. It is important to note that the properties of the cement slurry will change with mix density and temperature.

BHST (Bottomhole Static Temperature	50 degC [122 degF]
Density [lbm/gal]	15.8 lbf/gal expected (can be mixed between 12.5 to 16 lbf/gal)
Rheological properties determined with R1B5 after mixing (these will vary with cement mix density and temperature)	
PV (cp) (Plastic viscosity)	208
Ty (lbf/100ft2) (Yield Strength)	9
After conditioning at BHCT (If BHCT varies or the cement density varies the values below will also vary)	
PV (cp)	207
Ty (lbf/100ft2)	15
10 sec Gel Strength (lbf/100ft2)	7
10 minute Gel strength (lbf/100ft2)	32
Then 1 minute stirring gel strength (lbf/100ft2)	14
Stability	OK
API fluid loss at BHCT	54
Thickening time at BHCT	
30Bc	3h 54min
70Bc (unpumpable)	4h 31min
UCA cell compressive strengths	
50 psi	6h 16min
500 psi	8h 04min
24 hour comp. strength psi	2982

4.6 Drilling Fluids Program

The final drilling fluids program will be provided to US EPA before move-in and rig-up, and spudding of the well.

Conductor Hole (30-inch hole size)

This interval (if needed), may be pre-drilled with a portable drilling rig or a rathole company to approximately 60 feet (30 – 40 feet below GL). Drilling fluid is not planned for this section unless required by hole conditions. If it is required, a spud mud with a funnel viscosity in the range of 45 sec/1000 cc will be used.

Surface Hole (26-inch hole size)

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
0-400	Freshwater Gel	8.6 – 9.1	40 - 65	NC

Notes:

1) Lost circulation material (LCM) will be available on location to treat for fluid losses in shallow sands. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones.
2) Cement plugs may be used if necessary (e.g. upper Knox formation).
3) The fluid density will be maintained to contain the formation reservoir pressures without inducing flow to the wellbore.
4) High-viscosity gel sweeps may be used to assist hole cleaning.

Intermediate Hole (17-1/2-inch hole size)

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
400 - 5,400	Freshwater Gel	8.6 - 9.2	40 - 55	NC – 12

Notes:

1) Should lost circulation or fluid seepage occur, materials designed for that problem will be used to remedy the problem on an “as needed” basis.
2) The fluid density will be maintained to contain the formation reservoir pressures without inducing flow to the wellbore.
3) High-viscosity sweeps will be used as needed to assist hole cleaning.
4) The fluids may be treated with zinc oxide or zinc carbonate for potential hydrogen sulfide.

Production Hole Injection Interval (12-1/4-inch hole size)

To protect the formations from near wellbore permeability and porosity damage a Drill In Fluid (DIF) may be utilized. The fluid will be fresh water plus 3 – 6 % KCl and a premium grade non-dispersed xanthum gum (viscosifier) and starch (filtrate control) and sized $CaCO_3$ (bridging agent) and a biocide (bacteria control) and possibly a clay stabilizer.

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
5,400 – 7,200	3-6 % KCl/ Polymer	8.6 - 9.6	40 - 52	<12

Notes:

1) Should lost circulation or fluid seepage occur, graded calcium carbonate will be used to remedy the problem on an “as needed” basis.
2) The fluid density will be maintained to contain the formation reservoir pressures without inducing flow to the wellbore.
3) High-viscosity sweeps will be used as needed to assist hole cleaning.
4) Treat the drilling fluid with zinc oxide or zinc carbonate for potential hydrogen sulfide.

4.7 Completion Fluid

Potassium chloride (3 – 6 % KCl) fluids of fresh water may be used as the completion fluid and injection brine will be weighted with KCl to match formation fluid density. The weighted completion fluid would consist of fresh water plus the KCl with a biocide, corrosion inhibitor and possibly a clay stabilizer added. The fluid weight will be maintained to contain the formation reservoir pressures without inducing flow to the wellbore.

4.8 Coring Program

4.8.1 Conventional Whole Cores

A 7-7/8-inch x 4-inch poly-crystalline-diamond (PDC) core head with +/- 6-1/2-inch by 4-inch core barrel is proposed for the conventional coring portion of the well. The core barrel will be lined with fiberglass, PVC or aluminum sleeves. The following cores in the formations in the table below are proposed and will be attempted based on borehole conditions. TEC may elect to replace or supplement portions of the whole cores with rotary sidewall cores on some of the intervals listed.

Table 4-8

Proposed Conventional Whole Core Sampling

Regulatory Interval	Whole Core LocationNo.	Expected Depth (feet)	Core Length (feet)	Formation/Lithology	Core Barrel Size
Confining Interval	1	+/- 5,115 – 5,615	+/-30	Eau Claire Shale	7-7/8” x ± 6-1/2 x 4”
Proposed Candidate Injection Interval	2	+/- 5,615 to 7,200	+/-30	Mount Simon Sandstone	7-7/8” x ± 6-1/2 x 4”
Proposed Candidate Injection Interval	3	+/- 5,615 to 7,200	+/-30	Mount Simon Sandstone	7-7/8” x ± 6-1/2 x 4”

Supplemental rotary sidewall coring may occur and be performed to obtain additional reservoir data to fill in any gaps in the reservoir profile of the injection-confining formations as based on the openhole log evaluation. TEC and its geological consultant in consultation with site mud-loggers will evaluate and select the actual core points during the drilling of the well. If insufficient formation core is recovered in any core run, the core run may be repeated at the discretion of TEC with follow-up additional sidewall coring conducted as necessary to obtain geologic information.

4.8.2 Sidewall Coring

Horizontal rotary drilled sidewall cores may be collected in horizons of interest, and with a specific focus in the Confining Zone, the Injection Zone, and the Injection Intervals during the open hole logging of the protection and open hole injection interval sections to supplement or replace information. Actual sidewall core depths will be selected by TEC and its geological consultant based on the evaluation of the open-hole logs obtained, and the specific borehole conditions.

4.8.3 Core Analysis

Recovered conventional whole cores and any supplemental rotary sidewall cores will be analyzed for the basic reservoir core analysis including the following:

1. Core Gamma Ray (whole core only)
2. Reservoir Air Permeability
3. Reservoir Porosity
4. Effluent Compatibility (Injection Intervals only)
5. Bulk Density

Additional special core analyses may also be performed on selected intervals to obtain geologic and reservoir information. Some of these supplemental tests may include x-ray diffraction analysis for mineralogy determination, caprock (capillary or mercury) or confining layer permeability measurement, rock mechanics measurements including Poisson's ratio and Young's modulus for fracture gradient determination, as well as thin-section analysis and electron microscopy of injection intervals. Specific tests will be selected by the TEC and its geological consultant based on the evaluation program selected, the condition of the cores and integration of the open hole geophysical well log data obtained.

4.9 Formation Fluid Sampling

One or more intervals may be selected for fluid sampling. The fluid sample(s) will likely be recovered by drill stem testing of the formation. The fluid samples (if considered valid) will be collected and transported to a laboratory for detailed analysis including salinity, total dissolved solids, and formation chemical composition analysis. As an option, if borehole conditions allow, it may be decided to take downhole formation fluid samples during logging of open hole interval utilizing a formation fluid tester such as MDT* modular formation dynamics tester.

4.10 Mud Logging Services

A mud logging unit will be rigged up before drilling operations are started on the surface hole. The entire intervals of the 26-inch, 17-1/2-inch, and 12-1/4-inch holes will be logged with the following services provided:

1. Gas Detection
2. Drill Rate (Rate of Penetration--ROP) Curves
3. Lithology and Correlation
4. 1-inch Log
5. 2-inch Log
6. 5-inch Log
7. Minimum 30-foot Dry and Wet Samples (or as feasible based on rate of penetration)

4.11 Geophysical Logging Program

4.11.1 Surface Hole

The following open hole geophysical well logs may be run in the open-hole section of the 26-inch hole, with 20-inch surface casing hole at 400 feet:

- Resistivity
- Spontaneous Potential
- Natural gamma ray

- Open-hole caliper
- Neutron and density porosities

  Additional diagnostic logs may be run at the discretion of TEC and its geological consultant.

The following cased hole geophysical well logs will be run after cementing the surface casing in place:

- Temperature log

  Additional diagnostic logs may be run at the discretion of the TEC and its geological consultant. A copy of the log with letter of interpretation will be provided to US EPA.

4.11.2 Intermediate Hole

The following openhole geophysical logs may be run prior to running 13-3/8-inch casing in the 17-1/2-inch borehole from 400 feet to a depth of 5,115 feet:

- Resistivity
- Spontaneous Potential
- Natural gamma ray
- Openhole caliper
- FMI* fullbore formation microimager (borehole imaging survey recommended; also includes directional and deviation survey)
- Neutron and density porosities
- Fluid sampling (drill stem test and/or dynamic formation fluid tester)

Additional diagnostic logs may be run at the discretion of TEC and its geological consultant. Logs may include:

- Dipole Shear Sonic
- Rotary drilled side wall cores
- Magnetic Resonance Survey

The following cased-hole geophysical well logs will be run after cementing the 13-3/8-inch protection casing in place:

- Temperature log
- Cement Bond Log or USI* ultrasonic imager

Additional diagnostic logs may be run at the discretion of the TEC and its geological consultant. A copy of the log with letter of interpretation will be provided to US EPA.

4.11.3 Openhole Pre-Cambrian - Mount Simon – Eau Claire Interval

The following openhole geophysical well logs will be run in the 12-1/4-inch open-hole section of the drilled (production hole) borehole to characterize formation characteristics (lithology, connate fluid, etc.) of the Mount Simon Sandstone injection interval:

- Resistivity
- Spontaneous Potential
- Natural gamma ray
- Open-hole caliper
- FMI (borehole imaging survey recommended; also includes directional and deviation survey)
- Neutron and density porosities
- Fluid sampling (drill stem test and/or dynamic formation fluid tester)

  Additional diagnostic logs may be run at the discretion of TEC and its geological consultant. Logs may include:

- Dipole Shear Sonic
- Rotary drilled side wall cores
- Magnetic Resonance Survey
- Check shot survey

The following cased hole geophysical well logs will be run after cementing the 9-5/8-inch production casing in place, within the 12-1/4-inch borehole:

- Temperature log
- Cement Bond Log or USI

4.12 Survey Program

Deviation surveys will be run a minimum at every 500 feet as long as the hole angle is less than 3°. If hole angle exceeds 3°, then a change in the BHA will be made to straighten the wellbore. If hole angle increases over 5° then consider adding a monel drill collar in the BHA and using a camera survey tool.

4.13 Well Operations and CO_2 Injectate

Well operations and description of the proposed CO_2 injectate and its properties is described in this section below.

4.13.1 Component Streams Forming Injection Fluid

CO_2 is derived and captured from the coal gasification process. The proposed power plant will be a 730-megawatt gross (500-megawatt net) electric generation facility using an Integrated Gasification Combined-Cycle design, or IGCC.

4.13.2 Source and Generation Rate of Component Streams

The CO_2 source will be from the TEC IGCC coal gasification process.

4.13.3 Volume of Injection Fluid Generated Daily and Annually

Annual CO_2 injection for all wells could be up to 4,500,000 metric tons/year. Expected annual injection, based on current, preliminary plant design, is approximately 2,100,000 metric tons/year, assuming 92% availability under normal plant operations. Expected daily injection, per well is expected to range from 3,000 to 5,750 metric tons/day depending on site geology and injectivity A flow meter will be installed to produce a direct reading of total volume per time of CO_2 being injected. Location will be after compression, but prior to well head.

4.13.3.1 Injection Operations and Procedures

TEC's proposed injection procedures for all the site's injection wells incorporates short-term maintenance and inspection of the wells and surface equipment that the waste contacts, along with long-term monitoring and contingency planning for safe, responsible operations. TEC is committed to operating the wells to meet all applicable United States Environmental Protection Agency (US EPA) regulations for CO_2 injection wells. A detailed review of the monitoring program to be employed on the wells and surface equipment is provided in Testing and Monitoring Plan. Before injection Well No. 1 completion, the well will be shut in and will contain stabilized brine or fresh water. The wellhead will be flanged off and all valves locked close.

The operation of all site wells will include recording of various parameters including the injection flow, pressure, and annulus pressure which are continuously monitored and recorded on digital drives and/or backup charts. Since the injection facility will operate 24 hours per day, seven days a week, it will be continuously manned by TEC personnel, trained operators in injection well operations.

Initial injection rate and surface pressures for Injection Well No. 1 will be documented first providing some site history as a guide for future extended operations. Some variation of surface injection pressure is likely from well to well due to geologic heterogeneity and pipe frictional losses, however no long term unfavorable effects to injectivity are expected in the Mount Simon Sandstone due to its great reservoir thickness and suitability. For the purposes of developing the injection modeling, a maximum surface top-hole pressure of 2100 psia was used. The maximum surface injection pressure will be determined based on actual site conditions but will not exceed the pipeline design pressure. Depending on the number of wells needed at the site, the modeling indicates that average injection pressures are expected to range from 1600 to 1800 psia.

An annual Mechanical Integrity Testing Program will be conducted, consisting of an Annulus Pressure Test (APT), a Radioactive Tracer Survey (RAT), and Bottom-hole Pressure Falloff Testing.
The APT will demonstrate mechanical integrity of the casing-tubing annulus which includes the wellhead, tubing, casing, and packer systems. Additionally, a program of corrosion coupon monitoring near the wellhead will be in place pending final design. The RAT demonstrates where fluids are present within the Injection Interval, while the BHP Falloff tests satisfy the conditions of the Permit to monitor the pressure increase induced by fluid injection in Mount Simon Sandstone injection interval.

4.13.3.2 Operational Constraints – Maximum Allowable Surface Pressure

The primary operational constraint would be imposed by potential limitation of permitted injection volumes and Maximum Allowable Surface Pressure (MASIP). Once the TEC #1-injection well is drilled and rock mechanics and testing are complete, this upper bound to injectivity will be established. However, the maximum (surface) injection pressure is limited by the maximum design pipeline pressure which is 2220 psia (modeled tubing head pressures did not exceed 2100 psia).

4.13.3.3 Operational Contingency Plans

Contingency plans will be in place to identify situations where potential plant and/or process upset conditions may occur and take appropriate measures which are protective to the local area and the environment by shutting in the wells and monitoring their pressure falloff. Operational contingency plans for all TEC injection wells include potential downtime periods when annual Injection Well Testing, maintenance, well service, and stimulation occur. These plans include the following:

- Annual Testing of one Well at a time, monitoring via sensors, downhole and on surface;
- Sensors to detect malfunctions and potential leaks;

With multiple wells (up to four wells are planned) under the Permit, one well would normally be operational while the other well serves as a backup to continue seamless operations. Mechanical Integrity Tests (MIT) will be performed using U.S. EPA Region 5 guidelines for MIT and bottomhole pressure testing (U.S. EPA Region 5 Guidance). Additionally, BHP falloff tests could be completed on one well at a time, while the other well continues in normal operation. This is likely since the wells are sufficiently distant (~2-miles apart) where limited interference will occur within a good to excellent Mount Simon Sandstone injection interval.

The availability of multiple wells and adhering to proper TEC operations practices, including regular well maintenance and service, will reduce most injection well down-time and should eliminate the unlikely occurrence of one or more wells being simultaneously unavailable for use. In the unlikely event that all wells are temporarily unavailable or are out of commission, the CO_2 will be vented to the atmosphere for that limited period until operations and injectivity is re-established. Additional detailed monitoring, and other contingency planning for potential events that may occur during well injection operations are provided in Testing and Monitoring Plan and in the Emergency and Remedial Response Plan.

4.13.4 Physical and Chemical Characteristics of Injection Fluid

The values provided below are compiled using the projected wellhead maximum pressure and temperature conditions of 2,220 psig and 120° F, respectively. Characteristics of the CO_2 injection fluid could vary significantly at different locations in the compression and dehydration process and seasonally with changes in ambient temperature. Additionally, the wellhead pressure of 2,200 psig is used for preliminary design purposes and is dependent on final plant engineering design and construction.

A. Generic fluid name

Carbon Dioxide (CO_2)

B. Fluid phase

Supercritical

C. Complete waste analysis

Typical Analysis of Feed Stream
(Note: Some Variation is Possible Due to Site-to-Site and Day-to-Day Conditions)

Gas Composition %Mol			
Compound	**Normal**	**High**	**Low**
CH_4	trace	100 ppmv	0
CO	0.56 mol%	3 mol%	0
CO_2	98.38 mol%	100 mol%	92 mol%
COS	trace	100 ppmv	0
H_2	0.61 mol%	2.0 mol%	0
H_2O	trace	0.07 mol%	0
H_2S	10 ppmv	100 ppmv	0
MEOH	0.07 mol%	0.1 mol%	0
NH_3	trace	0.2 mol%	0
N_2	0.36 mol%	5.0 mol%	0
O_2	trace	100 ppmv	0
NO	trace	100 ppmv	0
NO_2	trace	100 ppmv	0
SO_2	trace	100 ppmv	0
$S0_3$	trace	100 ppmv	0
Ar	0.01 mol%	0.3 mol%	0
Sulfur	trace	10 ppmv	0
Hg	trace	400 ppbv	0

A quarterly sample bottle for the stream will be taken. The sample will be sent to a lab for to be analyzed. The test will include:

- CO_2 Purity (% mol by Gas Chromatography)
- Non-Condensable Gases
  - Hydrogen (H_2, % mol, by Gas Chromatography)
  - Oxygen + Argon (Ar + O_2, % mol by Gas Chromatography)

- Nitrogen (N_2, % mol by Gas Chromatography)
- Carbon Monoxide (CO, % mol by Gas Chromatography)
- Methane (CH_4, ppm by Gas Chromatography):
- Methanol (MEOH % mol by Gas Chromatography)
- Hydrogen Sulfide (H_2S ppm by Gas Chromatography)
- Total Sulfur Content (ppm by Gas Chromatography)

The gas sampling will be conducted downstream of the CO_2 compressor using a lined sample bottle. The gas sample will be send to an independent lab to be tested. Samples The exact locations and details of the sampling location will be provided as more design details are finalized and the completion report form 4h is submitted. The gas sample will be tested in an independent lab using ASTM 5954 and ASTM 6228 or ASTM 5504 or equal testing procedures.

D. Flash point

N/A

E. Organics

0.07 mol. % MEOH.
[Note: Some variation is possible due to site-to-site and day-to-day conditions.]

F. TDS

N/A

G. pH

N/A

H. Temperature

40-120 ° F. Typical operating temperature range 80-90 ° F

I. Density [at 2,200 psig, 120° F]

0.71 g/mL (44.4 lb/ft^3)

J. Specific gravity [at 2,200 psig, 120° F]

0.71 (liquid water = 1.0)

K. Compressibility [at 2,200 psig, 120° F]

$Cco_2 = 0.00045\ (psi)^{-1}$

L. Micro organisms

N/A

M. Chemical persistence

N/A.
Although CO_2 may exist indefinitely in the environment without being destroyed by natural processes, it does not bio-accumulate with potential long-term toxic effects.

EPA definition of persistence “A chemical's persistence refers to the length of time the chemical can exist in the environment before being destroyed by natural processes.”
[Ref. http://www.epa.gov/fedrgstr/EPA-TRI/1999/January/Day-05/tri34835.htm]

N. Key component name(s)

Carbon Dioxide (CO_2)

4.13.4.1 CO_2 Injectate Wellhead Composition

The table below contained a constituent and compound analysis from process design models of the composition of the process captured CO_2 proposed to be utilized for storage into in selected Mount Simon injection interval. It is nearly pure, 98.38 % as assayed, with minor associated impurities and constituents.

Gas Composition %Mol			
Compound	**Normal**	**High**	**Low**
CH4	trace	100 ppmv	0
CO	0.56 mol%	3 mol%	0
CO2	98.38 mol%	100 mol%	92 mol%
COS	trace	100 ppmv	0
H2	0.61 mol%	2.0 mol%	0
H2O	trace	0.07 mol%	0
H2S	10 ppmv	100 ppmv	0
MEOH	0.07 mol%	0.1 mol%	0
NH3	trace	0.2 mol%	0
N2	0.36 mol%	5.0 mol%	0
O2	trace	100 ppmv	0
NO	trace	100 ppmv	0
NO2	trace	100 ppmv	0
SO2	trace	100 ppmv	0
S03	trace	100 ppmv	0
AR	0.01 mol%	0.3 mol%	0
Sulfur	trace	10 ppmv	0
Hg	trace	400 ppbv	0

4.14 Surface Facilities for CO_2 Handling

At the TEC facility, the following surface facilities consisting of pipelines, meters, monitors will be in place for handling and transport of the CO_2 stream.

4.14.1 Injection Fluid Storage

Since the CO_2 will be handled on demand, and managed within the pipeline system and direct via the injection wells and the Mount Simon Sandstone formation, there is no need for the facility to have any on-site storage or tanks for CO_2.

<u>Storage capacity in days and gallons</u>	N/A. The injection wells will not have any onsite storage.
<u>Type of storage facility(s):</u>	N/A None.
<u>Storage capacity in case of well failure, (describe):</u>	N/A

4.14.2 Holding Tanks, Pipeline and Injection Flow Lines

The CO_2 pipeline will consist of a combination of 16-inch and 12-inch diameter carbon steel pipe. The pipeline will use ANSI 900 # valves and flanges rated for 2220 psi that are compatible for CO_2 service.

Each injection well will have a flow meter, isolation valve, and a control valve to regulate flows and pressures (Figure 4-6) and an annulus monitoring system to detect anomalies and leaks in casing, tubing, packer (Figure 4-7). A corrosion coupon monitoring system will be installed in the piping before the injection well. An internal corrosion monitoring program that meets ASTM requirements (Designation G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens) will be use on the pipeline and the injection wells. Weight loss coupons or electrical probes will be installed to monitor corrosion. Two coupons or probes will be installed at each injection well site. One coupon will be in the flow line. The other coupon will be located on the wellhead. The coupons for the flow lines will be made out of similar material as the line pipe. The coupons that are installed on the well head will be made out of similar material to the tubing. The coupons will be held in place using industry standard coupon holders. The coupons will be monitored twice each calendar year, at intervals not exceeding seven and one half (7½) months. The coupons will be cleaned, inspected, and weighed per ASTM G1 standards. All weights will be taken with an accuracy of +/- 0.1 of a milligram. The weight will be recorded. The weight will be used to calculate the corrosion rate in mils/year. I report for each coupon will be completed. The report will include the composition and size of the coupons, metallurgical conditions, surface preparations, and cleaning methods used as well as measures of corrosion rate, maximum depth of pitting or losses in mechanical properties.

If the coupons are found to have more than 3 mils/year of loss, corrective action will be taken. Potential actions could include a review to verify no water is in the system and the use of corrosion inhibitors. When corrosion is over the 3 mils per year limit, the coupons will be monitored more frequently. Whenever a pipeline or tubing section is removed, an inspection of the internal surface of all pipelines for corrosion will occur. If extensive internal corrosion exists a review of the pressure capability of the pipe and tubing will be conducted. If the corrosion has reduced the wall thickness of a segment less than that required for the maximum allowable operating pressure, the pipe will be replaced or working pressure reduced. The final P&ID will be included in the well completion report

4.14.2.1 Pipeline Operating Pressure

Maximum Allowable Operating Pressure (MAOP) of the pipeline is expected to be 2,220 psi with the pipeline using ANSI 900# fittings.

As indicated previously, no CO_2 holding tanks are planned at the injection wells since fluid will be managed via the multiple injection wells and Mount Simon Sandstone formation and venting.

4.14.3 Process and Instrumentation Diagram

A Process and Instrumentation Diagram has been included as Figure 4-6 detailing the preliminary design for the well delivery system including the pipeline configuration, control valves, recording and monitoring stations, pressure gauges and the injection well area.

4.14.4 Filters and Filtration

The CO_2 gas gathered and captured from the plant process will be free of dust, dirt, or other contaminates that would require a filter or filtration. No filters are planned to be installed at the injection wells. As indicated in the table of CO_2 composition, the injectate stream is relatively pure consisting of 98.38 % Mol. The following table pertaining to filters and filtration is not applicable.

1. Location	N/A
2. Type	N/A
3. Name	N/A
4. Model Number	N/A
5. Capacity, gallons per minute	N/A
6. Pore size, microns	N/A

4.14.5 Injection Pump(s)

The CO_2 will be compressed within the power plant and delivered to the injection well field under pressure. No injection well pumps will be required to deliver the captured CO_2 to the injection wells due to the fact that high pressure exists from the capture and compression process that will drive the CO_2 to the injection wells. The CO_2 will be compressed using two 50% capacity 8 stage integrally geared centrifugal compressors. Each compressor will be driven by an approximately 19,500 horsepower electric motor. The compressors will be equipped with intercoolers and after coolers to prevent excessive discharge temperatures. Flows and pressures will be controlled by inlet guide vanes using suction and discharge pressures as control points. In the event the inlet guide vanes are at the maximum travel distance, the system will recycle or vent CO_2 to prevent an over or under pressure situation. The compressor will have an emergency shutdown system. In the event a line leak or overpressure situation is detected, the emergency shutdown system will be activated to shut off flow of CO_2 to the pipeline.

4.15 Injection Fluid Compatibility

At the TEC facility, the following surface facilities consisting of pipelines, meters, monitors will be in place for handling and transport of the CO_2 stream.

A. Compatibility with injection interval

No compatibility problems are anticipated in the injection zone. Geochemical modeling was used to predict the effects of injecting supercritical CO_2 into a modeled Mount Simon Sandstone (ISGS, 2005). A geochemical model was completed to simulate geochemical reactions and was based on chemical and mineralogical data obtained from the Manlove Gas Storage Field in Illinois which is situated northeast of TEC site. Results show that the injected CO_2 decreased the pH of the formation brine initially to approximately pH 3.4. As the reaction was allowed to progress, the pH of the formation brine was buffered and increased to pH 6.7. Conclusions from modeling results indicate that these downhole injectate-brine-formation interactions and reactions from chemical processes will have a negligible impact on reservoir porosity. Additionally, the effects of mineralization and mineral precipitation should not reduce injection efficiency significantly.

B. Compatibility with minerals in the injection interval

In the geochemical simulations mentioned above ISGS (2005), predictions show that microcline dissolved initially. As the reaction was allowed to proceed, the mineral dawsonite ($NaAlCO_3(OH)_2$) was precipitated, and model predictions indicate that the volume of pore space in the injection interval would not be significantly changed (ISGS, 2005). Therefore, no compatibility problems, such as a major reduction in injection-formation permeability resulting from chemical precipitates are expected.

C. *Compatibility with minerals in the confining zone*

Results from geochemical simulations predict that as the CO_2-plume water reacts with the Eau Claire formation, illite would initially dissolve, but that the dissolved CO_2 could be precipitated as magnesite (ISGS, 2005). This dissolution and precipitation process is not considered to affect the integrity of the caprock.

Sources: ISGS, 2005. An Assessment of Geological Carbon Sequestration Options in the Illinois Basin. Phase 1 Final Report 2003-05, prepared for the U.S. Department of Energy by the Illinois State Geological Survey, pages 360-373.
(available at http://www.sequestration.org/).

D. Compatibility with injection well components

The preliminary subsurface and surface injection well design reflects the minimum requirements to sustain the integrity of the Eau Claire caprock to ensure that injected CO_2 remains permanently sequestered and stored in the Mount Simon Sandstone. The final well design will meet or exceed these requirements in terms of long-term CO_2 resistance and compatibility.

A discussion of the well components and specific compatibility injection tubing, long string casing, cement, annular fluid, injection packer, wellhead, and flowlines:

Injection tubing

Because the injected CO_2 has low water content, there is little reactivity with the injection tubing and overall effects will be negligible. No chemical deterioration is expected, however normal well monitoring and intervention if needed, is planned (e.g. in response to a coupling leak or pin-hole leak). The composition of the injectate should pose no adverse chemical reaction or degradation of the injection string. Periodic tubing calipers will be run and compared to the original baseline caliper to monitor tubing pitting or any other injection string degradation. The tubing materials selection is expected to improve long-term operations by decreasing the frequency of well workover requiring injection tubing replacement and repair.

Long string casing

The 9-5⁄8-inch injection casing (planned as the present design) will be cemented from the bottom of the 13-3⁄8-inch casing shoe and then back to ground surface, thus reducing any potential for fluid migration from brine and CO_2 into the annular space present between the drilled borehole and the casing. The lower section of the long string casing will be cemented with CO_2 resistant cement which should decrease the risk of channeling behind pipe. The section of the 9-5⁄8-inch casing which has the greatest potential for effects is that section of casing situated below the packer and end of tubing (EOT). This is the section of casing that will be subjected to the greatest long-term direct exposure to CO_2, while injection is occurring into the Mount Simon Sandstone. One casing and well design that can minimize potential risk of chemical degradation, is to include several joints of chrome-steel casing immediately above the injection packer. Throughout the lower section of the borehole, sufficient chrome-steel alloy 9-5⁄8 inch casing can be emplaced below the packer. In addition, casing caliper logs can be run (baseline first, and then follow-up during planned workovers) to determine adverse effects on potential deterioration of the 9-5⁄8 inch casing wall thickness. The supercritical state of the CO_2 stream with the absence of oxygen at depth (anoxic) should minimize any adverse affect, but this in part dependent on how long and to what extent the volume of CO_2 can be continuously injected. Moreover, the CO_2 will be dry at the surface. This will prevent reaction with water to make carbonic acid which could potentially corrode the exposed casing area below the packer.

Cement

CO_2 resistant cement will be used for the injection interval, and has been engineered to be more resistant to degradation by wet CO_2 and carbonic acid than traditional Portland cement-based well cement. The primary improvement in the CO_2 resistant cement over traditional Portland cement is the reduction in volume of the lime and water in the set cement. A comparison of increased compatibility of the CO_2 and the CO_2 resistant cement as compared to CO_2 and Portland cement is described following:

- The CO_2 resistant cement has very low Portland cement content in the set cement volume. Portland cement is the main component that goes through the carbonation process. By reducing its content, the durability of CO_2 resistant cement is significantly enhanced. Despite a low Portland cement content, high compressive strength is achieved (above 2,000 psi) over a wide density range (12.5 -16 ppg). Even though this system has a small amount of Portland cement, it does go through the carbonation process, but it is self-limiting and prevents further leaching.

- The CO_2 cement system is designed with an optimized particle size distribution (PSD). Consequently, the CO_2 resistant cement has very high solids content, i.e. water content is reduced significantly, compared to a conventional cement system. Low water content significantly reduces the permeability of the set cement matrix and strongly reduces the cement degradation rate due to CO_2 reaction.

- The CO_2 resistant cement is a lime ($Ca(OH)_2$) "free" system compared to conventional Portland cement; for example, a neat 15.8 ppg set cement has about 13% "free" lime content. The reaction between CO_2 and cement is primarily due to the presence of free lime. The rate of the reaction and the amount of calcite formed from the reaction is dependent on the amount of free lime present. This reaction creates porosity in the cement. Eventually, the CO_2 and water mix to form carbonic acid which will dissolve the calcite, which further increases the porosity of the cement.

- The dissolution of calcite degrades the mechanical properties of the Portland cement. For longer CO_2 exposure, Portland cement integrity is reduced by the dissolution of calcite under acidic conditions. By having a lime-free cement system, the resistance of the cement to degradation in a CO_2 environment is effectively increased compared to a conventional Portland cement system.

Annular fluid

The proposed annular fluid (packer fluid) contains fresh water or 2-3 % potassium chloride (KCl), very low solids, and is filtered to less than 50-75 microns with both diatomaceous earth (DE) and filter pod filtering systems. The weight of the packer fluid will be controlled so as to have enough hydrostatic weight to easily kill the well (expected formation gradient pressure in the Mount Simon Sandstone at depth is expected to be normal gradient (0.433 psi/ft) when or if any well intervention has to occur during any time of the life cycle of the well.

There is no risk of unexpected reactions with the annular fluid and the injection fluid that may breach the injection tubing. The packer fluid, 2-3 % KCl, with a small concentration of corrosion inhibitor is compatible with injected CO_2 and will minimize corrosion of the injection casing and tubing. The worse reaction case would be a slow, almost immeasurable mass of CO_2 entering the annulus and lowering the ph of the annular fluid in the vicinity of the tubing leak. However, while the mass may be very low, the leak would be detected by the change in the annular surface pressure monitoring equipment almost immediately and injection would cease. Any leak may require that the tubing string be pulled, inspected, and repaired or replaced as needed, and the annular fluid would be replaced with a fresh 2-3 % KCl water and corrosion inhibitor.

Packer(s)

Engineering design and plans are to run a hydraulically set elastomer based packer system. This packer will be set hydraulically via the tubing rather than a mechanical-set packer. The packer and the amount of weight that will be set on top of it will be designed to account for the buckling and all other forces that will be exerted during the injectivity phases, in order to ensure that it does not become “unset” by itself, thus ensuring integrity of the annulus.

The packer has a CO_2 compatible elastomer like Viton™ which offers excellent resistance to CO_2 and the rest of the injection stream. The dry CO_2 should not react with the steel components of the packer. The packer will be a quantum* gravel-pack packer family packer, a Baker Model SC-2P, or similar packer. The packer will be made from corrosion resistant material that will be compatible with both the casing and the injection stream. The quantum packer is rated to 6,000 psi and 250°f.

No “blanket” of diesel or kerosene or similar non-reactive fluid will be placed below the packer. CO_2 is less dense than water and is less dense or very similar in density to many hydrocarbon liquids like diesel and kerosene. It is highly unlikely that these types of fluids would remain in place under the packer from buoyancy effects with CO_2. Additionally, West Texas CO_2 enhanced oil recovery (EOR) injection wells place nothing below the packer and have no compatibility related problems.

Fluid Spotting

A fluid spotting program may be designed to correct skin damage the well has been completed and evaluated. The general program would include:

- 50 to 100 bbl 15% to 28% HCl spotted across injection zone
- Inhibitor (e.g. Schlumberger A261 or equivalent)
- Iron Stabilizer (e.g. Schlumberger L041 or equivalent)
- Surfactant (e.g. Schlumberger F100 or equivalent)

Well head equipment

At present the wellhead assembly will consist of the well head, a Christmas tree valve control assembly made up of a minimum, 2-SS master valves (a swab valve and another a master) with a 3,000 psig wing valve. The master valve and wing valve will be outfitted with an automatic shutdown device, all being steel (Xmas tree & upper assembly). This will allow for easy nippling up of blowout preventers and minimal intervention if any is required during the life of the well. The dry CO_2 should not react with the steel components of the wellhead. This suggested design is similar to wellhead equipment used in West Texas and Mississippi EOR projects.

Holding tanks(s) and Pipeline injection flow lines

As previously indicated, there will be no holding tanks for the injection fluid; consequently, there are no CO_2 holding tank compatibility concerns.

The flow line header pipeline from the TEC plant compressor to the injection well site is expected to be 16-inch (OD) carbon steel, grade X65 and a wall thickness of 0.625 inches. After the first injection well is drilled and completed, the pipeline size to the outer injection wells will be reduced to 12.75-inch (OD) with 0.375-inch wall thickness, grade X65 carbon steel pipe. The 12.75-inch pipeline is designed for periodic inspection (pigging) and all piping will have all necessary cathodic protection.

As a result of the cooling, dehydrating and compressing process, the CO_2 stream will be relatively dry or free of water. Dry CO_2 is compatible with schedule 40 or 80 carbon steel pipe. This pipe is routinely used in the CO_2 injection oil fields of West Texas and Mississippi. There are no compatibility concerns between the CO_2 and the flow lines between the compressor and the wellhead.

Compatibility with filter and filter components

There are no plans to filter the CO_2 prior to injection. Consequently, there are no compatibility concerns between the CO_2 and filters and filter components. The CO_2 from the process is subsequently compressed and cooled will not have any particulates entrained in the CO_2 stream. As such there are no compatibility concerns since no filters or filtering components are present in the system.

Full description of compatibility concerns

At this time there are no known compatibility concerns within the Mount Simon Sandstone injection interval, or the injection zone, or with minerals in the injection and confining zone. The CO_2 is expected to have negligible to no reaction with the formation minerals and formation native brine. Any reactions that may occur are not expected to affect the containment of the CO_2 below the primary seal of the Eau Claire.

If water is present within the CO_2 stream, then expectations are that potential compatibility issues from materials degradation and corrosion associated with wet CO_2 may occur. Components and materials of the injection wellhead and wellbore will be selected to minimize and negate any significant reaction with the CO_2. Any elastomers used in the well design will be selected based on exposure, contact resistance with CO_2 and their robustness for long-term effectiveness.

4.15.1 Pre-Injection Fluid Treatment

Other than standard CO_2 gas compression, and cooling (as needed to optimize compressor utilization and for transport), at the TEC site there is no pre-injection fluid treatment involved or planned for the injection fluid (CO_2).

4.16 Request for Low-pressure Annular Monitoring System

The current regulations for Class VI wells (Section146.88(c) requires that: ''The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.''

For the injection wells at Taylorville, this type of system, where the annular pressures requirements would be very high, would threaten well integrity and would not be protective of the USDW. Installation of an annular pressure system, where surface annular pressures are 100 psi greater than surface injection pressures would create the following conditions (Figure 4-8):

- Annulus pressure of 2,320 psi surface pressure
- Annulus pressure 4,830 psi at the packer (this exceed formation frac pressure)
- 4,200 psi Bottom hole flowing pressure
- 630 psi bottom hole differential and 1000 psi during normal operation
- 2,320 psi pressure differential across casing

Some of the risks associated with the pressured annulus include:

- High differential pressure across casing could cause casing leaks
- Annulus pressure is over to frac pressure for the entire length of the tubing string
- High differential across tubing could cause leaks
- High annular pressure is likely to create a microannulus outside of the long string and can damage cement isolation capacity
- Cycling of pressures will put additional stresses on the cement
- High annular pressures at the surface create additional hazards for those working near the surface equipment
- High pressure would mask small CO_2 leaks and could lead to corrosion issues

The TEC injection wells will be equipped with a low pressure annular system designed around atmospheric pressure. The proposed TEC system includes continuous pressure monitoring at surface and downhole and will provide an immediate response and notification to the operator, via the SCADA system, whether there is a leak from the annulus or if CO_2 is entering the annulus via the tubing or around the packer. A vacuum would indicate an annulus leak; a pressure build would indicate a tubing or packer leak. The presence of CO_2 gas in the annular fluid would confirm the leak.

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APPENDIX 1-1

TENASKA TAYLORVILLE ENERGY CENTER PROJECT DATA SHEET

APPENDIX 1-2

TYPE LOG OF ESTIMATED FORMATION DEPTHS AND STRATIGRAPHIC COLUMN

FOR TEC SITE CENTRAL ILLINOIS

Area of Review and Corrective Action Plan

1.0 Facility Information

Facility Name: Taylorville Energy Center

Applicant Name: Christian County Generation, L.L.C.,
1044 N 115 St., Suite 400
Omaha, NE 68154-4446

Facility Contacts: Ryan Choquette, Manager Midstream Engineering
Ph. 402-938-1641
e-mail rchoquette@tenaska.com

Location: 1630 N 1400 E Road, Taylorville, Christian County, IL 62568

2.0 Area of Review (AOR)

Geologic and reservoir flow models were used to develop a preliminary determination of the area of review (AOR) for the Taylorville Energy Center (TEC) project.

The AOR is based on the *Maximum Extent of the Separate-phase Plume or Pressure-front (MESPOP)* methodology, as detailed in the relevant US EPA guidance document (USEPA, 2011). Information about the lowermost Underground Source of Drinking Water (USDW) and target injection zone obtained from offset wells, 2D seismic surveys, and other published data provided the input for the hydraulic head calculations specified in the guidance (Locke & Mehnert, 2011). The following table summarizes the input to the calculations. Results of these calculations indicate that the pressure front in the injection zone ($P_{i,f}$) is delineated by a change in pressure of approximately 180 psi above the initial reservoir pressure. Based on computer modeling of the proposed 30-year injection, the MESPOP grows to a maximum extent (Plate 1) and is exclusively defined by the pressure front and not by the extent of the injected carbon dioxide (CO_2). As a result, the CO_2 remains within the AOR throughout the entire simulated period. Plate 1 outlines the predicted maximum extent of the pressure front within the injection interval over a topographic map of the immediate area around the project site. It should be noted that the jagged shape of the AOR polygon is an artifact of the simulation grid and not physically realistic. Once site-specific data are gathered during installation of the first injection well (TEC #1), the

AOR will be re-evaluated. Additional details of the model input parameters and results of the simulation are discussed in Section 3 of the Technical Report and summarized in the below.

.	General Information	Lowermost USDW	Injection Zone
Ground Elevation	615 ft. above mean sea level (MSL)		
Gravity	9.80 m/s^2		
Fluid Density		1000 kg/m^3	1135 kg/m^3
Pre-injection Fluid Pressure		34.66 psi	2844 psi
Pre-Injection Pressure Head		80 ft. below ground surface (BGS)	5784 ft. BGS
Elevation Head		100 ft. (BGS)	6250 ft. BGS
Pre-Injection Hydraulic Head		20 ft. BGS	466 ft. BGS

3.0 Computational Modeling

3.1 Model Names:

Geologic Model – Petrel* seismic-to-simulation software
(2009, 2010, and 2011 releases)

Reservoir Model – ECLIPSE* reservoir simulation software
(2009, 2010, and 2011 releases)

3.2 Description of Models:

Both Petrel and ECLIPSE are commercial software packages available from Schlumberger Information Solutions (SIS), an operating unit of Schlumberger. SIS provides software, information management, IT, and related services.

Petrel seismic-to-simulation software enables effective geological assessments, descriptions, and visualizations of the subsurface. Petrel incorporates data from a variety of sources (e.g. seismic, wireline, well logs) into a single, static geologic model.

ECLIPSE dynamic reservoir model uses the Petrel geologic model as a starting point for 3D numerical reservoir simulations. ECLIPSE includes enhanced modules specifically for CO_2 storage simulations that account for salting-out effects, temperature, and pure water-density modeling.

3.3 Model Inputs and Assumptions

The model will be updated following completion of the first injection well. The location and construction of additional wells, and operational details will be optimized for the well field at that time. This permit application is for the installation of TEC 1 and TEC 3 (See Figure 3); reservoir flow modeling iterations were completed for one, two, three, and four well scenarios.

A geologic model for the Mount Simon Sandstone was constructed over a large area of central Illinois from the available geologic, geophysical, and petrophysical evaluation of all available data, including cores, 2D reflection seismic lines, and well logs. A complete description of the modeling input including regional and site geological information, along with a full description of the modeling is attached in the Technical Report (Attachment 1).

The ECLIPSE simulator and modeling results focused on a base case of injection through three injection wells; the injections scenarios were optimized, using the model, for four injection wells. It is the primary tool used to predict results and identify formation intervals for the TEC #1-injection well. All modeling results indicate that CO_2 injection at the TEC is feasible. Model optimization tasks have been reviewed and have evaluated alternate cases (e.g. low-high, additional wells, etc.).

The simulation model is composed of the simulation grid along with rock and fluid properties, well completion, and pressure data. To investigate the feasibility of handling the CO_2 at the prescribed rate, an integrated flow line and well flow PIPESIM* production system analysis software model was set up and coupled with the ECLIPSE reservoir dynamic model. This covers the flow stream from the compressor to the reservoir.

The CO_2 storage option in ECLIPSE provides the means to include a CO_2 rich phase, an H_2O rich phase and a solid phase (salt content). The mutual solubilities of CO_2 and H_2O are calculated to match experimental data for CO_2-H_2O systems under typical CO_2 storage conditions: 54-212 ^{o}C and up to 8,700 psig.

Other key modeling input and assumptions include:

- Geo-cellular model covers an area of 30 square miles.
- The geo-cellular model contains over 6.7 million cells.
- Each grid cell is 300 m x 300 m in areal extent with an average layer thickness ranging from 1.5 feet to 7.6 feet.
- The grid was coarsened away from the core area to allow reasonable run times. The coarsest grid cells at the outer model boundary measure 2,400 x 2,400 m.

- The simulation model contains over 350,000 cells.
- The injection reservoir is the Mt. Simon Sandstone at a depth of approximately 5600 feet to 7000 feet.
- The Eau Claire Formation, overlying the Mt. Simon, is the primary upper sealing formation; other secondary sealing formations include the dense dolomites within the Knox group, the Maquoketa Shales, and the New Albany shale.
- The underlying confining unit is the basement granite formation.
- Porosity and permeability were populated based on analog well log data.
- Vertical permeability is assumed to be 32 % of horizontal permeability.
- The reservoir is assumed to be 100% brine saturated with a formation salinity of 97,000 ppm at 6,000 ft true vertical depth (TVD) at initialization.
- For modeling purposes, the injected gas is assumed to have the behavior of pure CO_2.
- At the expected range of pressure and temperature throughout the flow system, the CO_2 is likely to be either a liquid or a super-critical fluid.
- Hysteresis and solid precipitation are included in the model. Residual water saturation is 25 % whereas residual CO_2 saturation is 20 %.
- The model was equilibrated as a normally pressured reservoir with a normal gradient of 0.433-psi/foot used. This equates to an initial reservoir pressure of 2,598 psi at 6,000 feet TVD and 3,002 psi at a bottomhole depth of 6,932 feet TVD.
- Reservoir temperature was calculated at 119^{o} F at 6,000 feet TVD using a temperature gradient of 1^{o} F/100 foot and an ambient temperature of 59^{o} F.
- Due to the lack of site-specific information on the Mount Simon Sandstone formation, an estimated pressure gradient of 0.65 psi/ft was selected to use in the Base Case Model run.
- With this constraint, a maximum injection bottom hole pressure of 4,376 psi at the Mount Simon Sandstone mid-point of the completion (perforation) depth of 6,732 ft TVD.
- A maximum allowable injection rate of 239 lb/s CO_2 (approximately 4 million metric tonnes per year) was distributed evenly to the simulated injection wells.
- An average Tubing Head Pressure (THP) of 2,100 psi for each well was employed in the simulator, with actual THP as high as 2,220 psi.
- The model assumed 30 years of continuous injection.
- There are no known faults or fractures in the reservoir and caprock within the study area.

4.0 Project Summary

The TEC is being developed by Christian County Generation, L.L.C. The project is proposed as a 730-megawatt (gross) facility using an Integrated Gasification Combined-Cycle design, or IGCC. The plant will be located approximately two miles northeast of Taylorville in central Illinois, and is anticipated to have a start-up operational date of 2015. The fuel source for this plant is coal from the Illinois Basin area. The injection well field will be comprised of up to four injection wells and is designed to operate a minimum of 30 years. However, this permit application is for two wells (TEC 1 and TEC 3). Attachment 1 contains more detailed information on regional and site geology, a summary of the 2D seismic survey, and a detailed discussion of the site modeling.

4.1 Site Description

The TEC project area is located in Christian County a little over two miles northeast of Taylorville, Illinois, a town whose population is approximately 11,427, and situated along State Route 48, and approximately 30 miles to the southwest of the city of Decatur (pop. ~109,309). Land use of the area is predominantly agricultural, the terrain is flat, and the land is held mostly by private landowners for growing row crops. There is minimal present day oil field infrastructure in the area. Access to the TEC site area is from State Hwy 48 or 29, with numerous gravel roads, farm access roads, and paved roads existing within the project area (Figure 1). Four proposed injection wells are planned and located within the area covered by three 2D seismic lines that were acquired in July 2009.

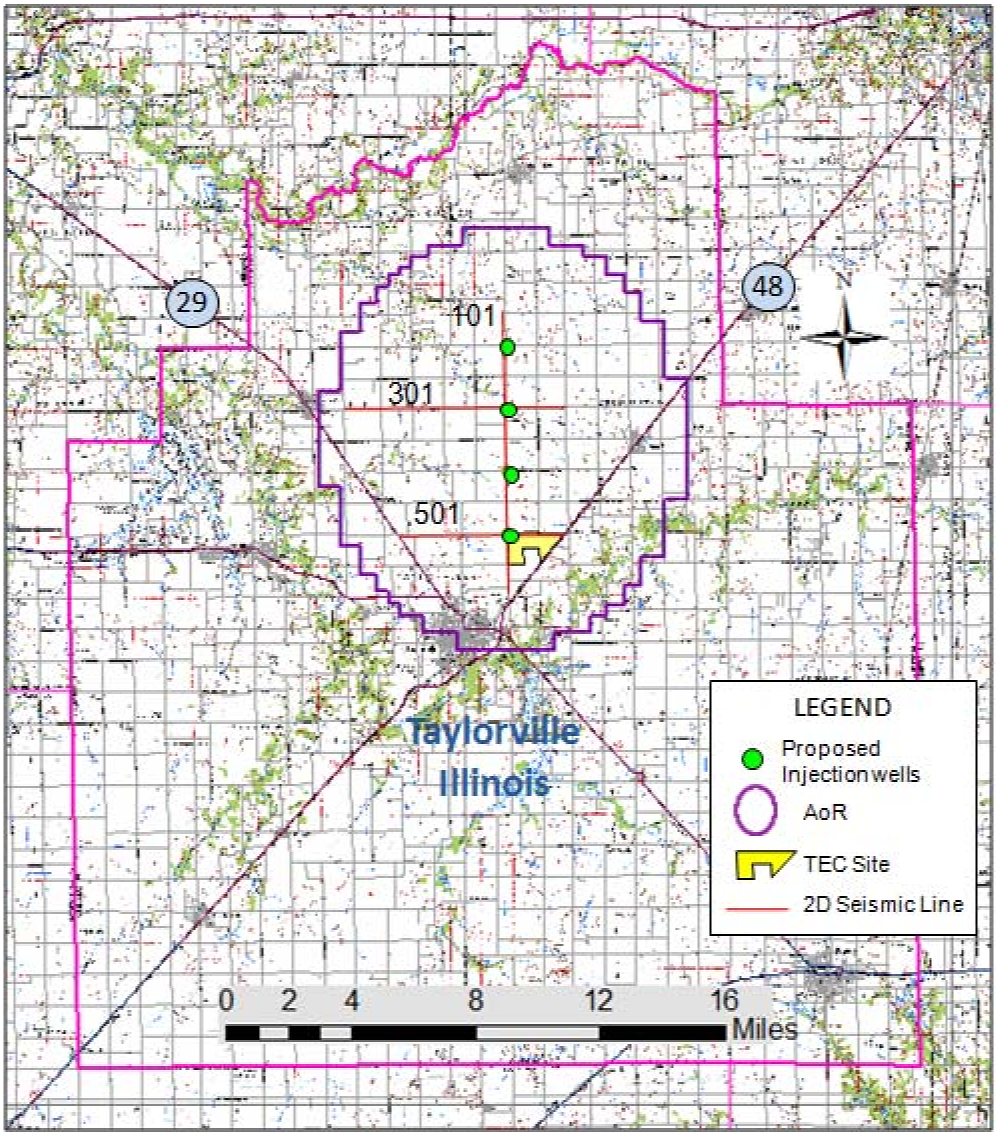

Figure 1. Topographic map of the area

4.2 Site Characteristics

There is relatively little topographical relief in the study area (see Figure 1-1, Appendix 1-1). The hydrographic features in the area consist of natural and man-made drainage and stream channels that flow predominately to the northwest. The land use within the area is largely agricultural with row crops and pasture lands. There are 14 incorporated areas that have commercial and residential land uses including Taylorville.

4.3 Surface Features

The relevant near-surface and sub-surface geologic features in and around the proposed TEC site include shallow aquifers, mineral resources, and mines. There are many shallow glacial and alluvial aquifers present in the area that act as a water sources [Midwest Technology Assistance Center 2009A and 2009B]. Most groundwater in the area is withdrawn from shallow unconsolidated formations for personal and agricultural uses. The base of the lowermost USDW is defined locally as those freshwater intervals where effective water usage occurs, and ranges from shallower near-surface glacial till aquifers to a conservative estimate of less than 200 feet. The drilling of the initial #1-injection well and subsequent wells will assist in specific depth and definition of these aquifers.

4.4 Surface Stratigraphy

The local surface strata are Pennsylvanian in age, and consist of interbedded shale, sandstone, limestone and coal seams. From the TEC site the Pennsylvanian rock cover on the surface and with depth exhibits a subtle dip to the southeast into the Illinois Basin. The Illinois Basin is characterized by the filling in of younger sedimentary rock.

4.5 Coal Seams

Throughout most of Illinois, coal is prevalent throughout Pennsylvanian-age strata. The most notable coal seam in the area is the Herrin coal seam (Figure 2). The Herrin coal seam has been mined mostly in the south, southwest, and east of the proposed injection wells, and locally, this coal seam has a thickness of over five feet.

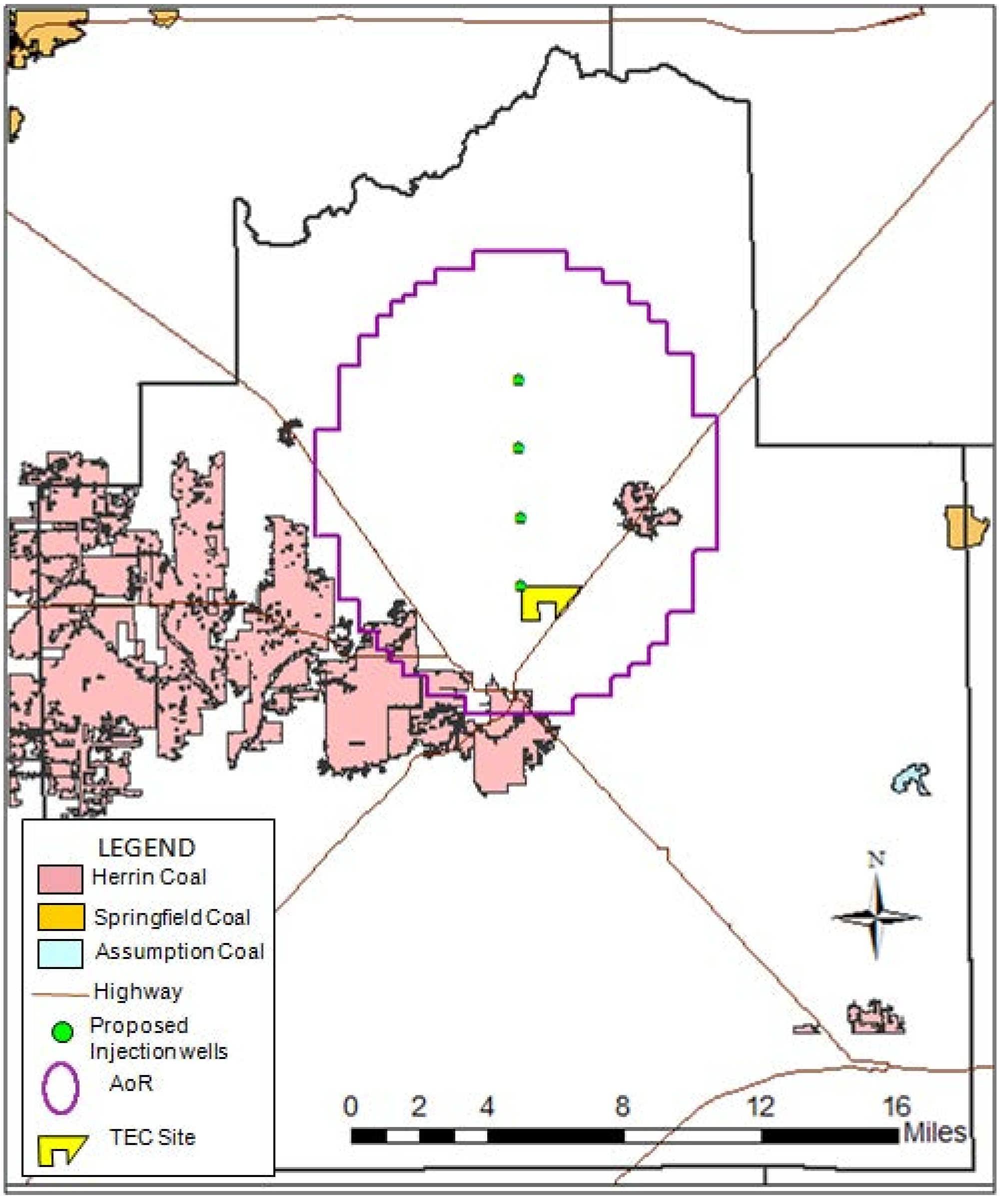

Figure 2. Near-surface features map showing coal seams such as the Herrin seam which has been mined locally.

4.6 Well Inventory

An inventory of wells drilled in the area include appraisal wells, oil and gas production wells, gas storage wells, water production wells, and water injection wells. Within a the 12-mile radius that encompasses the AOR of the proposed injection site, based on public record, there are 1504 water production wells, 191 water disposal wells, 191 confidential wells, and 2807 other (oil, gas related, and others) wells (Figure 3). None of the wells penetrate the Eau Clair caprock or the Mt. Simon Sandstone.

Only 4 wells in the vicinity of the TEC site penetrated the St. Peter Sandstone formation and three of those wells are now abandoned. The deepest of these wells is a 3,252 foot well which was utilized as a salt water injection well, while the other two wells were of shallower depth. Additional review of the area indicated there are no underground natural gas storage fields present within the AOR. The closest gas storage field is the Hillsboro Gas field which is present approximately 27 miles southwest of the proposed TEC facility and storage site and which injects gas into the St. Peter Sandstone formation.

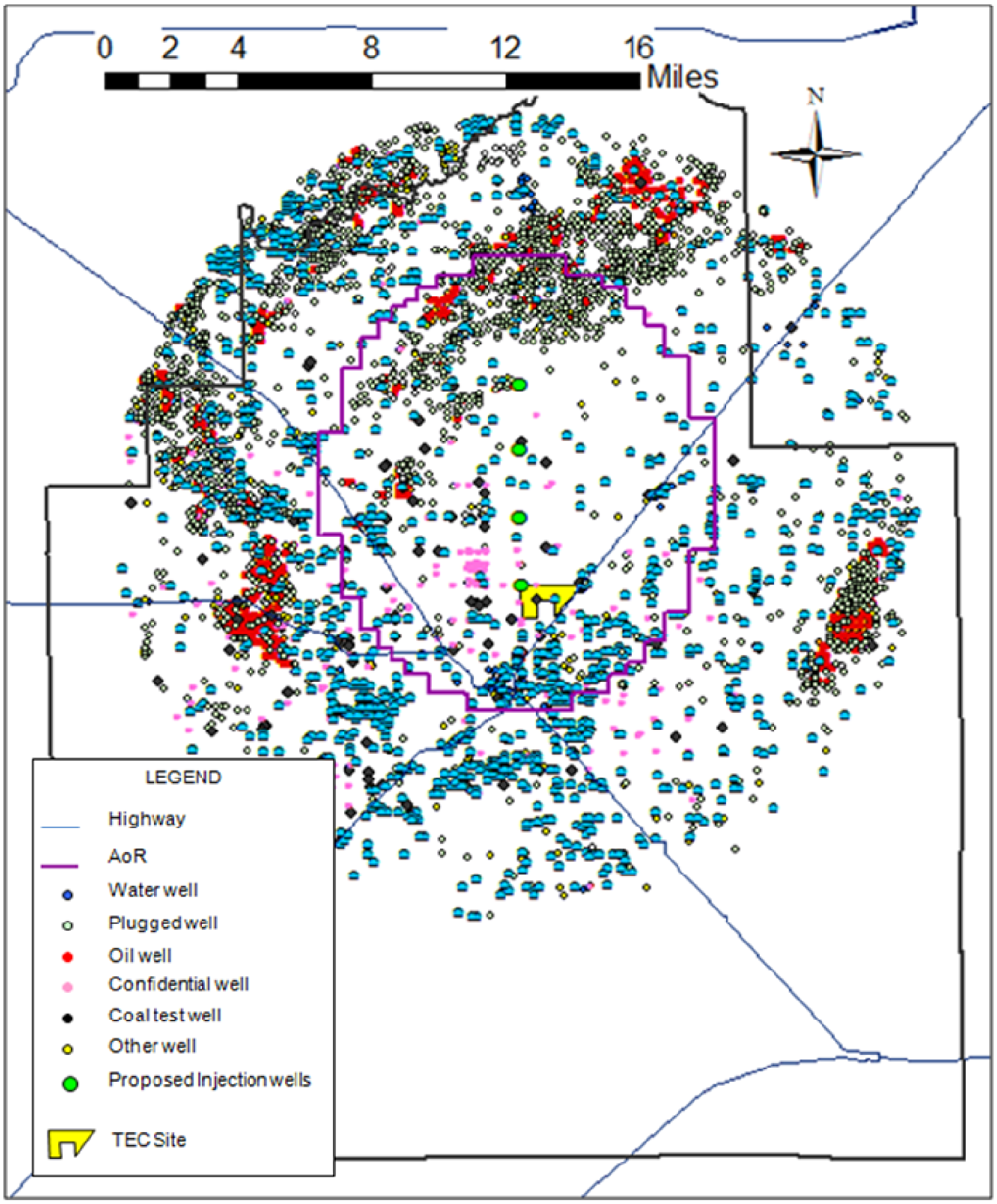

Figure 3. Inventory of wells identified in a 12-mile radius encompassing the AOR of the proposed TEC site.

The proposed TEC #2-injection well may encounter the presence of some minor shallow hydrocarbons, however, these potential oil and gas resources are considered relatively small in extent and likely non-commercial. More importantly, they are located at much shallower depths than the proposed deeper Mount Simon Sandstone CO_2 storage interval and will have no impact on the project except that the project must be designed to ensure protection of Illinois natural resources via a robust well design and completion program for the injection wells.

5.0 Geological Study and Model

A comprehensive geological study and model using available data has been completed to develop a preliminary evaluation of the suitability of the Taylorville site for long-term storage of CO_2 in deep saline formations under the facility. This work represents the initial phase of developing a geologic storage site for CO_2 sequestration using the Mount Simon Sandstone formation as the injection interval.

5.1 Study Objectives

The goal of the study was to:

1. Calculate site capacity for storing expected volume of CO_2 from the plant;
2. Identify containment of the Mount Simon Sandstone storage reservoir; and
3. Define infrastructure requirements for storage (number of injection wells, spacing, operational strategies).

5.2 Findings

The results of the geologic and reservoir evaluation study indicate that the Mount Simon Sandstone has sufficient porosity (open void space between the sand grains in the rock) and permeability (the degree to which the pore spaces are interconnected, allowing fluid to move through the rocks), and therefore provides a storage reservoir target suitable and capable of accommodating all of the CO_2 produced by the TEC over the planned operational life of 30 years. The Eau Claire formation, which overlies the Mount Simon Sandstone, will provide the vertical containment needed to prevent movement of CO_2 out of the Mount Simon formation and into shallower geologic formations. There are also several other zones of low permeability layers that provide secondary containment. The Mount Simon formation and the containment layers are laterally extensive and available information, including the results of a subsurface (seismic) survey confirm that there are no faults or breaks in the lateral continuity of the formation. This provides further support that the CO_2 will remain in place.

The storage reservoir is situated over 5,000 feet below the active regional municipal, and commercial drinking water supplies. A review of available studies and data from the Taylorville and Christian County area indicate that the Mount Simon injection reservoir is situated well below all USDWs as defined by the U.S. EPA.

5.3 St. Peter Sandstone to Eau Claire Shale to Mount Simon Sandstone

The St. Peter Sandstone formation is situated well above (~2,000 feet) the Eau Claire confining unit and Mount Simon Sandstone injection horizon, but since there is no site specific salinity information present, there remains potential that it could be less than 10,000 mg/l total dissolved solids. Therefore, if < 10,000 mg/l is encountered, it would be defined by U.S. EPA as a potential deep USDW and must be protected with adequate casing and cement isolation within final injection well design. The St. Peter has been used regionally as a disposal zone for Class II wastes (See Section 2.11 of the Technical Report.)

After permitting, drilling the initial TEC #1-injection well will define the salinity profile for all formations and identify any area USDWs and their specific depths. A specific consideration is to define the salinity of the St. Peter Sandstone for purposes of protective well design and monitoring. Situated below the St. Peter Sandstone, the Eau Claire Shale provides the primary seal and vertical containment of the injected CO_2, which will remain confined and trapped within the deeper Mount Simon Sandstone injection reservoir.

6.0 Seismic Acquisition, Processing, and Interpretation

WesternGeco conducted a local 2D seismic survey over and surrounding the proposed TEC site to provide data to evaluate the suitability of the subsurface formations for CO_2 storage. The survey included acquisition of a total of approximately 21 miles of high resolution reflection seismic data. The specific formations of interest are the immediate caprock and seal, the Eau Claire Shale identified from seismic data as a reflector present at an approximate depth of 5,151 – 5,615 feet, and the injection storage reservoir, the Mount Simon Sandstone at depths of ~5,615 – 6,915 feet. The survey also provided an assessment of the lateral continuity of the overlying formations of interest and whether there were any faults or displacement of the formations identified that could potentially compromise the reservoir seal integrity and containment.

County road permits were secured for performing the 2D seismic survey with public information and notification made to affected parties and neighbors to inform them of the activity and to answer questions regarding the survey. In July 2009, WesternGeco, along with subcontractors (Survey Technology Inc, Conquest Seismic Services and VibraTech Monitoring Services) deployed survey markers, geophone strings, three truck-mounted vibrators, and the advanced system for acquisition and processing of seismic data. The acquisition of surface 2D seismic data (a total of 21 miles), its quality control, and processing was performed by the contractor. Final seismic data processing was performed using WesternGeco's Omega* seismic data processing software.

The field party crew successfully concluded this project, using the advanced recording system while fully complying with the Quality, Health, Safety and Environment (QHSE) Management System (MS) of Schlumberger as well as with CCG's project requirements.

The final product post-processing and enhancement were generation of three enhanced 2D seismic lines, with data consisting of one north-south trending Seismic Line L-101, and two east-west lines, Seismic Lines L-301 and L-501 (Figure 4). These data were loaded into Petrel software for interpreting subsurface data and geological interpretation. Detailed seismically defined geologic models of the subsurface formations were developed and prepared over the proposed plant site area. The models also included positioning and placement of four proposed injection wells at a surface elevation of 612 feet, with inter-well spacing placed 2-miles apart trending in a northerly direction from the TEC plant site (Figures 4 and 5).

6.1 Geologic Interpretation of Seismic Data

The Eau Claire Shale is known to exist as a broad regional reflector feature and was easy to distinguish in the velocities of the seismic data from the overlying, dolomitic and carbonate Knox Formation (Figure 4). Shale is a very fine grained dense rock that has extremely low permeability, thus providing an excellent confining layer and containment for the injectate. The Eau Claire Shale will serve as an excellent confining layer and the primary seal to the Mount Simon Sandstone injection interval reservoir. The Mount Simon is a sandstone formation deposited in an ancestral fluvial environment. This river setting has characteristic sedimentary structures associated with braided features of the river, which commonly introduces formation heterogeneity (variability) into this rock unit. The seismic survey verified that the Eau Claire Shale and Mount Simon Sandstone are laterally extensive throughout the study area and AOR. Synthetic seismograms were also developed based on other regional velocity data, with detailed synthetic logs generated to assist in interpretation of the subsurface geologic model within the injection and confining beds.

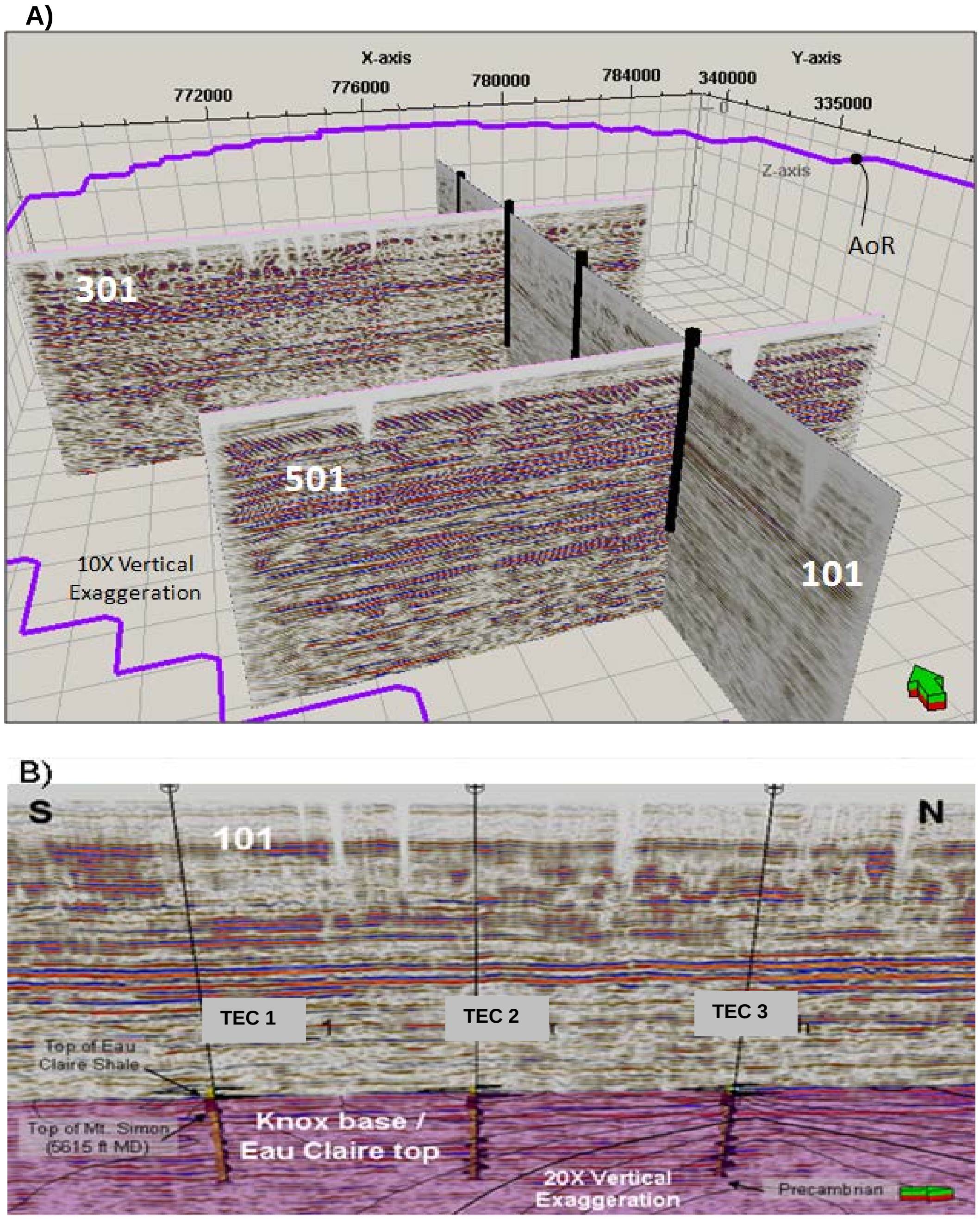

Figure 4 (A,B)
Three 2D seismic lines are shown in relationship to three of the proposed TEC injection wells.
Note: A) Four proposed TEC injection wells with 2-mile spacing and AOR (purple line).
B) Gamma ray logs and synthetic seismograms based on sonic logs were used to interpret the contact between the base of the Knox dolomite and the Eau Claire Shale.

6.1.1 Seismic Interpretation of Stratigraphy and Dip

A detailed review of the 2D seismic data from Lines 101, 301, and 501 show no apparent discernable faults dissecting the Paleozoic section. The reservoir model, consisting of horizons interpreted from the seismic, dips to the southeast by no more than one degree per mile, representing a relatively gentle rate of dip. Although the injected CO_2 will be less dense than the existing brine and be buoyant in the Mount Simon Sandstone, the geologic slope or dip of the Mount Simon is very gentle with lateral distance from the site such that long-term or short-term migration of the CO_2 will not be accelerated due to the slope of the injection interval. In summary, an interpretation of 2D seismic data at the site revealed a gentle stratigraphic dip of less than 1 degree striking to the southeast.

6.1.2 Mount Simon Sandstone Injection Interval

The seismic interpretation at the TEC site shows relatively uniform bedding for the Mount Simon Sandstone reservoir, the caprock, and the shallower formations. Subtle sedimentary features were noted in the Mount Simon injection interval indicating variations. However, since this formation consists of a braided fluvial system, this type of variability and geologic and reservoir heterogeneity are to be expected. The seismic lines did not reveal the presence of any specific faulting in the Mount Simon Sandstone or the Eau Claire Shale horizons at the site.

The Mount Simon Sandstone rests on an interval referred to as the “Granite wash”, which is comprised of weathered and reworked materials deposited from the underlying, granitic, Pre-Cambrian basement formations.

In south-central Illinois, the Midwest Geological Sequestration Consortium (MGSC) has prepared a regional map of the Mount Simon Sandstone formation based upon study of available well logs and data. At the Taylorville site, the expected top of the Mount Simon Sandstone is approximately ~5,615 feet (from seismic correlation) and the expected sand thickness ranges from 1,100 to 1,300 feet, which places the base of the Mount Simon injection interval reservoir as deep as approximately 6,900 feet below ground surface.

The Mount Simon Sandstone contains numerous intervals consisting of relatively clean sand with abundant pore space (porosity) present between the sand grains. Multiple Mount Simon Sandstone layers are shown in the reservoir flow model and represent periodic variations in the formation’s permeability. This is a key property and consideration when modeling geologic heterogeneity of reservoir properties in a storage reservoir.

6.1.3 Eau Claire Shale Confining Interval

The overlying Eau Claire Shale section consists of very fine particles such as silt and clay. Shales, deposits have compact layers and limited connected porosity. And they have even more limited vertical permeability. Therefore, it is considered to be an excellent confining interval and a seal, acting as a vertical barrier to fluid out-flow from the Mount Simon Sandstone.

6.1.4 Stratigraphy of Overlying Intervals

Numerous alternating confining intervals of low permeability and porosity are present above the primary seal, the Eau Claire Shale, and serve as secondary and tertiary containment beds. These consist of the Knox Dolostone, the Maquoketa Shale, and the New Albany Shale units, all known as regional seals and confining horizons throughout the Illinois Basin area.

6.1.4.1 Knox Dolostone Confining Interval

Above the Eau Claire Shale confining interval, the Knox Dolostone is approximately 1,500 feet of section that is largely characterized as very low primary permeability, dense, massive dolostone. This section serves as an additional major confining interval of limited porosity and permeability above the deeper Mount Simon injection interval.

6.1.4.2 St. Peter Sandstone Interval

Situated above the Knox Dolostones, approximately ~180 feet, is the St. Peter Sandstone. The St. Peter Sandstone is water-bearing, regionally present, and exhibits good reservoir pore space, while in some areas of Illinois it is utilized for the storage of natural gas and historically has been used for disposal of oil-field brine wastes. The St. Peter is overlain by Ordovician dolostones followed by the presence of a potential secondary caprock, the Maquoketa Shale.

6.1.4.3 Maquoketa Shale Confining Interval

The Maquoketa Shale section is regionally present, with a thickness of approximately 200 feet at the site, and serves as an additional confining seal above the Mount Simon Sandstone injection interval. Above the Maquoketa Shale are more dolostones of Silurian and Devonian age which provided additional confinement capability.

6.1.4.4 New Albany Shale Confining Interval

At the transition of the Devonian and Mississippian age rock formations is the regionally present New Albany Shale, which offers an additional layer of containment between the deeper Mount Simon Sandstone Injection Interval reservoir and the base of shallow drinking water supplies.

The New Albany Shale has a thickness of approximately 125 feet. At a depth of approximately 2,100 feet (below ground level), this shale unit offers another additional seal above the St. Peter Sandstone.

6.1.4.5 Mississippian to Pennsylvanian Intervals

Above the New Albany Shale are alternating units of Mississippian limestone and sandstone which contain some oil reservoir intervals. Moving upward from the Mississippian into the Pennsylvanian aged sediments, are numerous coal seams present in the area. These coal seams alternate with intervals of sandstone, shale, and limestone. Some of these shallow coal seams have been mined locally.

7.0 Reservoir Model Development

A 30 by 30 mile area of interest was selected for development of the reservoir model for this project. This scale was required to enable reservoir engineering models to describe subtle pressure changes at a lateral distance from the TEC injection site without the model boundaries affecting the results.

A graphical reservoir model was setup, and consisted of 27 identified Mount Simon Sandstone zones and up to 264 total flow layers. The initial model resolution consisted of 6.7 million cells that are 300 meters square for an appropriate depiction of the subsurface based on seismic data.

A detailed discussion of the base-case modeling is included as Section 3 of the Technical Report.

7.1 Reservoir Modeling Results

The available set of geologic and well log data were used to develop a computer model that describes the geologic and reservoir conditions at the site (Figure 5). Operating options were then developed through an iterative process and flow simulations were run to evaluate the numbers and general design considerations for injection wells, and to evaluate the size and movement of the injected CO_2 and the associated pressure front. Preliminary modeling results based on conservative reservoir model inputs suggest that a base case of three injection wells provide the necessary capacity to handle the expected volume, and provide optimum injection operations. The modeling results using these broad inferred geologic assumptions and inter-well spacing distances confirm that no more than four wells are required to manage the site's injection. Following completion of drilling and detailed geological and reservoir evaluation of the first injection well (Well #1), consideration of potential variations in site geologic conditions will be made. Well #3 would be the next well installed under this permit. In the event that a greater inter-well distance and spacing, and/or additional injection wells (i.e TEC #2 and TEC #4) are required to manage the site injection requirements, then the appropriate permits would be requested.

Model results show that the areal extent of the CO_2 would occupy approximately 21 square miles (3.2 miles by 9.3 miles) and that the long-term injected CO_2 will stabilize and remain in approximately the same position as at the time the injection operation ceases. Following injection, pressures in the reservoir decay and return to near normal background pressures. This also removes advective driving forces and mechanisms that could act to move the CO_2 vertically and/or laterally.

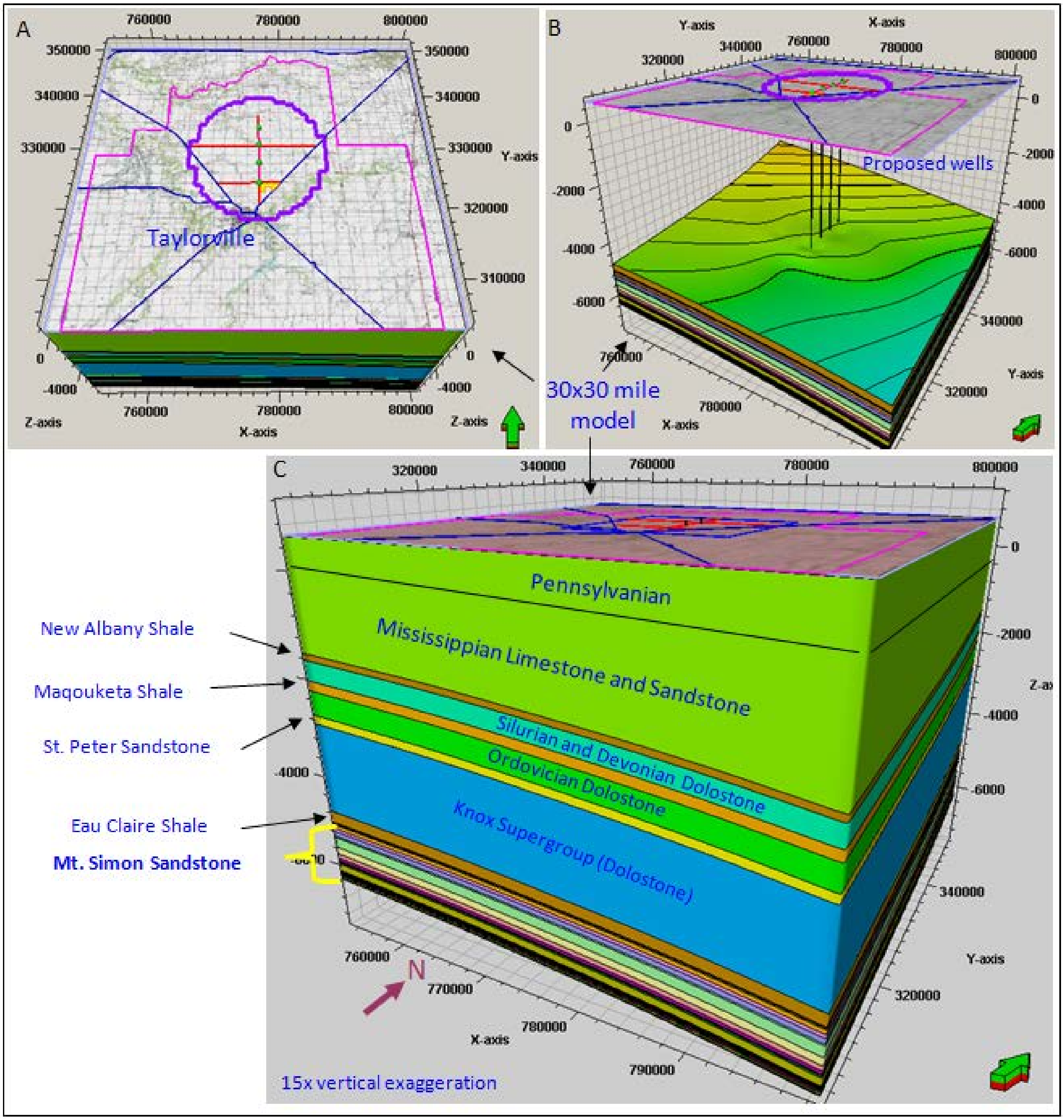

Figure 5 Geological model for a 30 x 30 mile Area of Interest (AOI) around the CCG Taylorville site.

A) Oblique map view of the proposed CCG wells north of Taylorville, Illinois.

B) Cut-away view of the model showing the proposed wells penetrating the top of the Eau Claire Shale. Based on 2D seismic data, the strata dips to the southeast by less than one degree.

C) Layer cake geological model illustrating some of the key reservoirs and seals within the AOI.

Note the dip to the southeast. The Mount Simon portion of the model is refined with many layers to realistically represent the vertical petrophysical variations and geologic heterogeneity present in the formation.

7.2 Injection Pressure and CO_2 Modeling Results

The reservoir modeling results focused on a Base Case of injection through three injection wells and serve as a baseline to compare other model cases which incorporated uncertainties in reservoir properties and alternative development strategies. This model base case includes the best estimates of reservoir and surface facility design features, reiterated here.

- Geological model based on seismic and analog well data;
- Injection start date of January 1, 2015;
- Injection end date of January 1, 2045;
- Simulation end date of January 1, 2145;
- Maximum Injection Pressure gradient of 0.65 psi/foot (modeled)
- Injection rate of 239 lbs/s of $CO_{2;}$
- Tubing Head Pressure (THP) of 2,100 psi for each well;
- Maximum source pressure of 2,220 psi.

Given the current model results, it is apparent that the full capacity of the forecasted TEC field CO_2 injection can be managed with four injection wells given the imposed Bottomhole Pressure (BHP) and THP limitations of the initial maximum injection pressure operational gradient of 0.65 psi/foot (82% of the estimated area fracture gradient of 0.79 psi/foot). A measured operational gradient and fracture pressure definition for the Mount Simon will be obtained following evaluation and testing of the initial injection well. The modeled pressure response to CO_2 injection is shown over time in Figure 6 below. For visualization of model results, the reservoir is bisected or cut north to south along the plane of the injection wells to observe the maximum pressure response present as predicted by the model. For each time step or date the change in pressure is shown relative to the starting date of the simulation (January 1, 2015).

Reservoir pressure increases are present over background initial conditions during the 30-year injection period but the model predicts falloff to near the initial background Mount Simon Sandstone pressure conditions by the end of the long-term 100-year study period. The areal extent of the pressure response is contained within the model area.

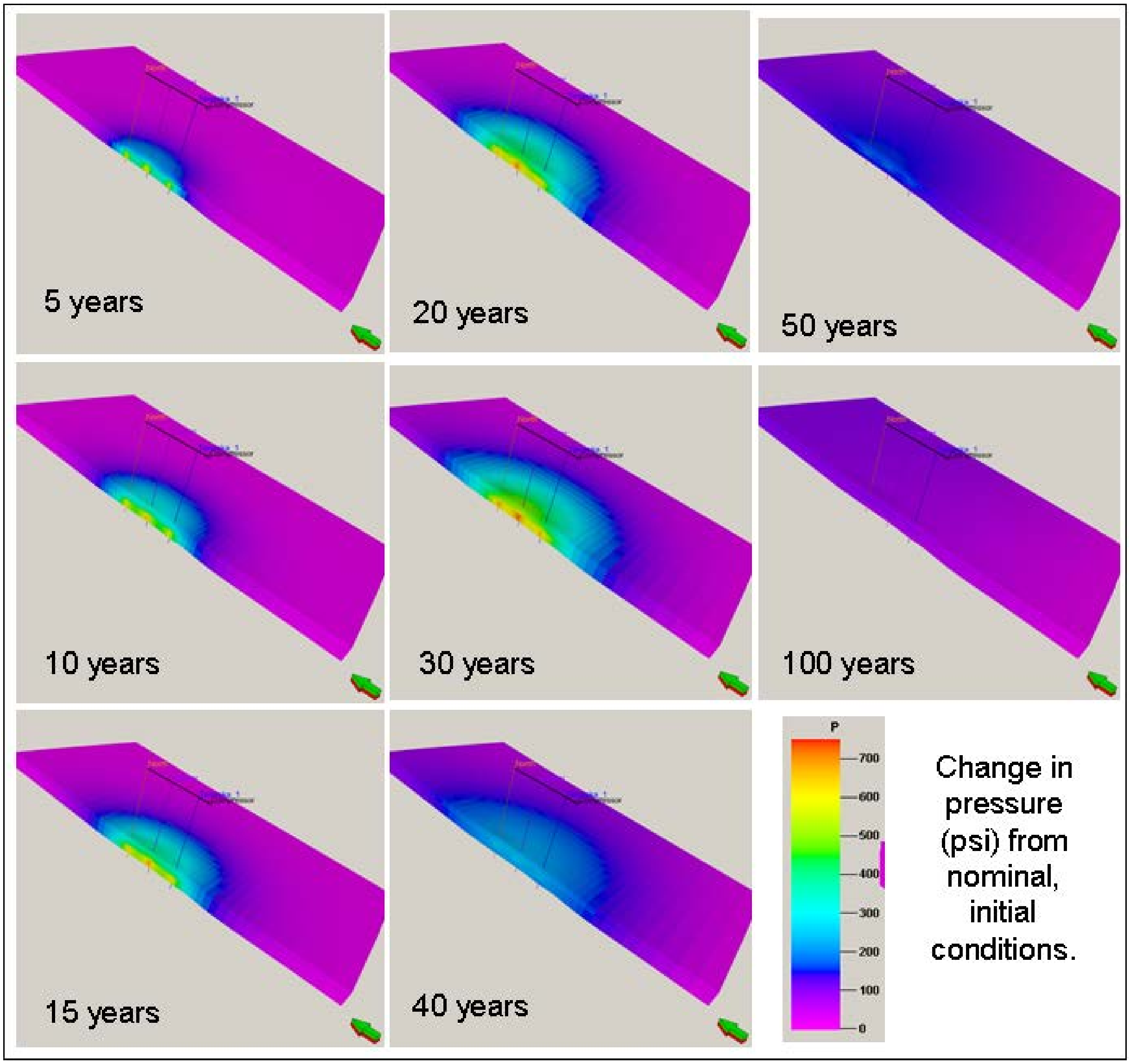

Figure 6 Oblique, cut-away view of the Mount Simon reservoir base-case model showing three of the injection wells and changes in reservoir pressure through time. (See Section 7.6 for four-well case and development of AOR.)

Change in reservoir pressure is shown relative to the January 2015 starting date of the simulation run. After 30 years of constant injection, the pressure begins to declines back to initial conditions from Years 31 - 100.

As CO_2 is injected into the formation a plume develops and the areal extent is estimated both during the injection period and for specified future periods of 40, 50, and 100 years in the post injection period. The plume extent is largely dependent on the distribution of porosity and permeability in the reservoir model. As each layer is assigned constant reservoir properties for both permeability and porosity, the model results are optimistic for total predicted injection volumes. However, without additional site reservoir data and information which is planned for recovery from the TEC #1-injection well, this model case offers the best estimate and prediction of future site injection and subsurface reservoir conditions at present.

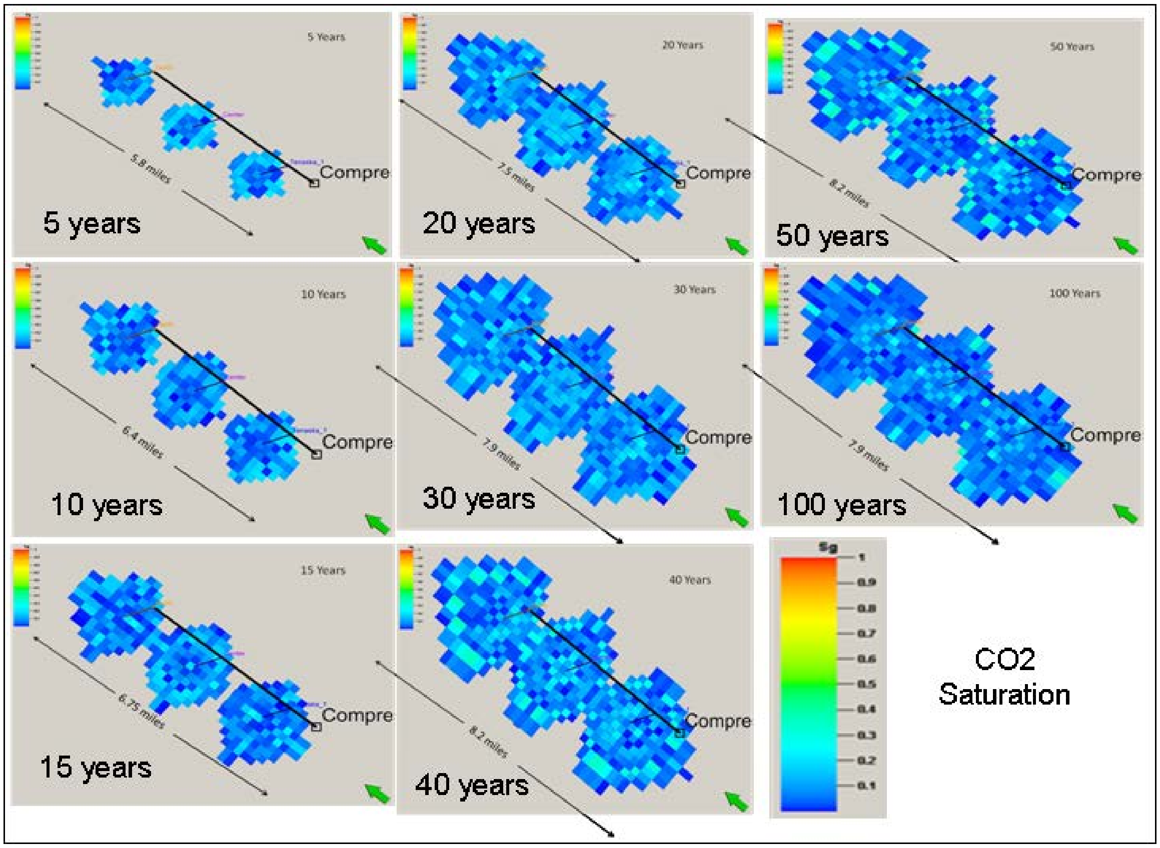

Figure 7 Aerial view showing development of the base-case CO_2 plume and its migration through time. (See Section 7.6 for four-well case and development of AOR.)

At the end of 30 years of injection, the overall maximum total extent of the plume from the four injection wells is 9 miles oriented in a north-south configuration. At the end of 100-years, the plume has migrated no further up-dip. Following CO_2 injection cessation, in the long-term ‘recovery’ period, the plume size does not change significantly with time after injection ceases (see Figure 7).

7.3 Summary of Base and Alternate Cases

In summary, the modeling shows that there is adequate storage capacity in the reservoir and that the overlying formation(s) provide containment layers that prevent vertical movement of the CO_2 and brine.

From an operation standpoint, several scenarios were considered and cases developed for detailed modeling and analysis. Following completion of the first well, the model will be updated and operational cases will be optimized using site-specific data and information from the geologic formations and acquired reservoir information.

Although one well could be adequate to handle CO_2 injection, it may not be adequate to sustain secure continuous injection operations (not exceed geologic constraints or permitted operating conditions). In addition, one well would not provide any backup or excess capacity to the injection management system in the event of contingencies that might render a single well unavailable due to maintenance or for other reasons. Four injection wells were placed on two-mile spacing and this was established as the "Base Case" run for the reservoir model. This design provided a good range of operating conditions and provided the flexibility needed for optimizing injection. Two-well, three-well, and four-well scenarios were evaluated as alternate cases or scenarios. Other factors considered for analysis and optimization included variations in reservoir conditions (e.g. porosity and permeability; pressure, fluid, and rock strength gradients), various well designs and configurations (e.g. well diameter, injection zones within the reservoir) and variations of the condition of the CO_2 (e.g. purity, temperature, and well head pressure).

7.4 Produced and Captured CO_2

The CO_2 produced by the plant, which is over 98 % pure CO_2, will be compatible with the existing formation fluid (brine or native formation saltwater that is at least several times saltier than sea water). With these parameters, the site meets the criteria for a Class VI Permit Application under the Underground Injection Control (UIC) regulations, which fulfill requirements of the Safe Drinking Water Act.

The following table represents the expected chemical composition of the TEC CO_2 product.

Gas Composition %Mol			
Compound	**Normal**	**High**	**Low**
CH_4	trace	100 ppmv	0
CO	0.56 mol%	3 mol%	0
CO_2	98.38 mol%	100 mol%	92 mol%
COS	trace	100 ppmv	0
H_2	0.61 mol%	2.0 mol%	0
H_2O	trace	0.07 mol%	0
H_2S	10 ppmv	100 ppmv	0
MEOH	0.07 mol%	0.1 mol%	0
NH_3	trace	0.2 mol%	0
N_2	0.36 mol%	5.0 mol%	0
O_2	trace	100 ppmv	0
NO	trace	100 ppmv	0
NO_2	trace	100 ppmv	0
SO_2	trace	100 ppmv	0
$S0_3$	trace	100 ppmv	0
AR	0.01 mol%	0.3 mol%	0
Sulfur	trace	10 ppmv	0
Hg	trace	400 ppbv	0

The captured CO_2 gas stream is expected to total approximately 3.42 million metric tons/year, with maximum expected CO_2 flow of 9,367 metric tons/day.

7.5 Coupled CO_2 Pipeline and Reservoir Simulations

Coupled CO_2 Pipeline and Reservoir Simulations were completed for the TEC site through an iterative process to develop various injection scenarios and operational cases. This process examined a variety of conceptual designs from which a "Base Case" model scenario and alternate model cases were developed.

The pipeline and well sizing calculations were performed using PIPESIM 2009, which is a steady-state, multiphase flow simulator used for the design and diagnostic analysis of oil and gas production systems and injection wells. PIPESIM was used to simulate the various operational scenarios to identify the maximum number of injection wells required to inject 239 lbs/s of CO_2 without exceeding the 2,220 psia limitation at the compressor. Parameters considered in the pipe simulations included:

- the gas composition,
- compressor operating pressure,
- temperature,
- distances between the wells,
- operating scenarios, and
- the internal diameters of the surface pipelines,
- injection pipe size,
- the geothermal gradient,
- trajectory and depths of the wells.

A schematic of the proposed injection wells and pipe network is shown in Figure 8.

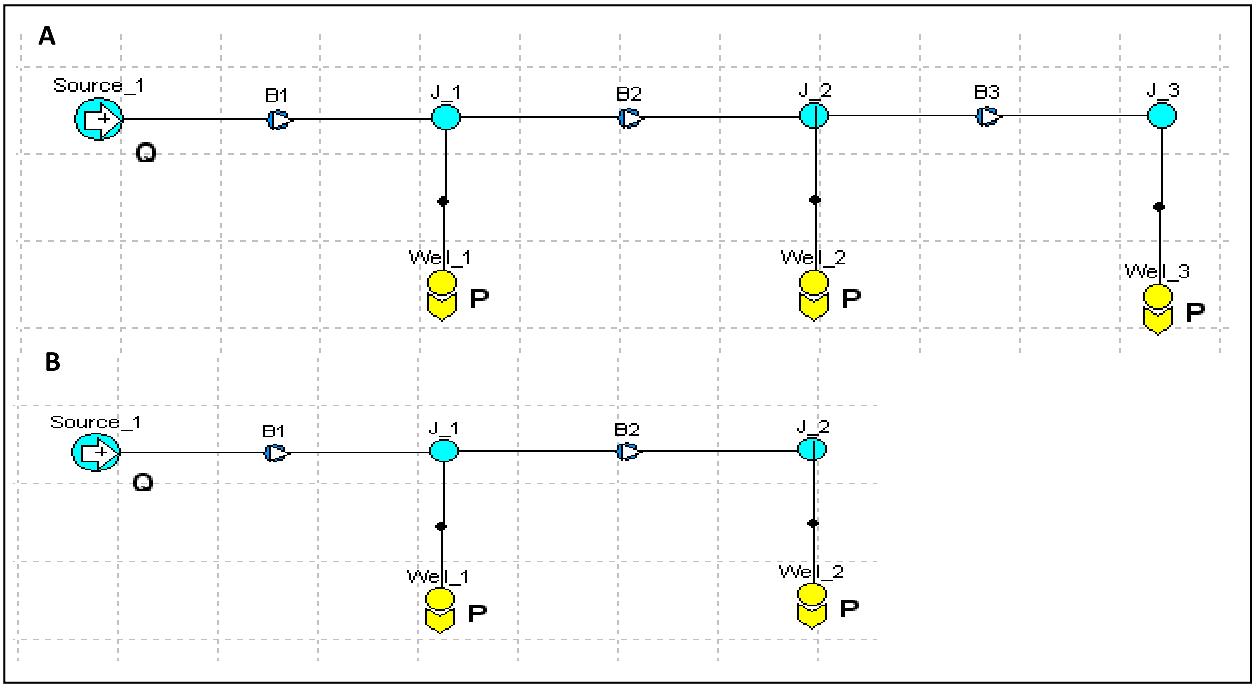

Figure 8 Pipeline networks for the 5.5-inch tubing (Model Run A) and the 7-inch tubing (Model Run B) injection wells used in the PIPESIM modeling.

The simulation also investigated two different injectate fluid compositions. One where the injectate composition consisted of pure CO_2 (100 %), and the other where the composition was specified as 98.4% CO_2 with impurities and accounted for the bulk of the CO_2 that would actually be generated at the facility and stored in the Mount Simon Sandstone injection interval.

Based on the results of the simulations the following conditions were established for the modeling in order to select either 5.5-inch or 7-inch tubing:

- The Injection rates were modeled as equally divided between all the injection wells for both fluid composition scenarios and tubing sizes. These results will maintain an erosional velocity ratio less than one.
- For the 5.5-inch injection tubing case, the maximum permissible injection rate per well, in order not exceed to the erosional velocity of one, is 84 lbs/s.
- If 4 injection wells are used, 5.5-inch injection tubing would be adequate.
- The pressure versus temperature plots show that the injected CO_2 fluid stays in single phase throughout the network.

- For all 7-inch injection tubing scenarios, the use of three injection wells met the erosional velocity criterion with erosional velocity ratios less than one.
- In some cases the temperatures and well head pressures can be maintained under the various injection scenarios to maintain the stability of the CO_2.

Following the completion of the initial simulations (Model Runs 1 through 8), 5 additional simulations were conducted using a network system utilizing 3 injection wells with 7-inch tubing configuration (Figure 8).

An integrated approach was used with the reservoir engineer generating the reservoir model and coupling the results of the pipe simulations in preparation of a number of injection cases. These cases considered different pipe sizes, injection rates, two and three wells, plus a number of various reservoir conditions in a coupled fashion.

Final model results indicate that the use of 7-inch tubing offers the best solution and approach to the design and injection well considerations and this will be employed as the base case and selected option. At present, the plan is to construct two wells (TEC 1 and TEC 3) with this design.

7.6 Four-well Case and Development of the AOR Boundary

A four-well injection case was modeled as part of evaluating alternative injection system designs, improving injection efficiency upon system initialization, and to establish the preliminary AOR. Figure 9 shows that the four-well case is capable of handling the cumulative injection and verifies the efficiency of reaching maximum injectivity in the shortest amount of time. Figures 10, 11, and 12 illustrate the injection profile plots for a single injection well with various pressure constraints. The analysis shows that maximum injection can be achieved with the application of a very conservative fracture pressure (0.65 psi/ft gradient).

CO_2 saturation and the change in CO_2 areas over time are shown in Figures 13 and 14 respectively. Comparing the CO_2 saturation area to the pressure change boundary of 180 psi (See Section 2) indicates that the CO_2 saturated area is always contained within the pressure boundary (Figure 15). Figure 15 also shows that the maximum extent of the pressure boundary occurs at the end of 30 years of planned injection. This boundary is used to establish the AOR. Figures 16 and 17 show the growth of the boundary and then relaxation of the boundary after the end of injection (e.g. Figure 18).

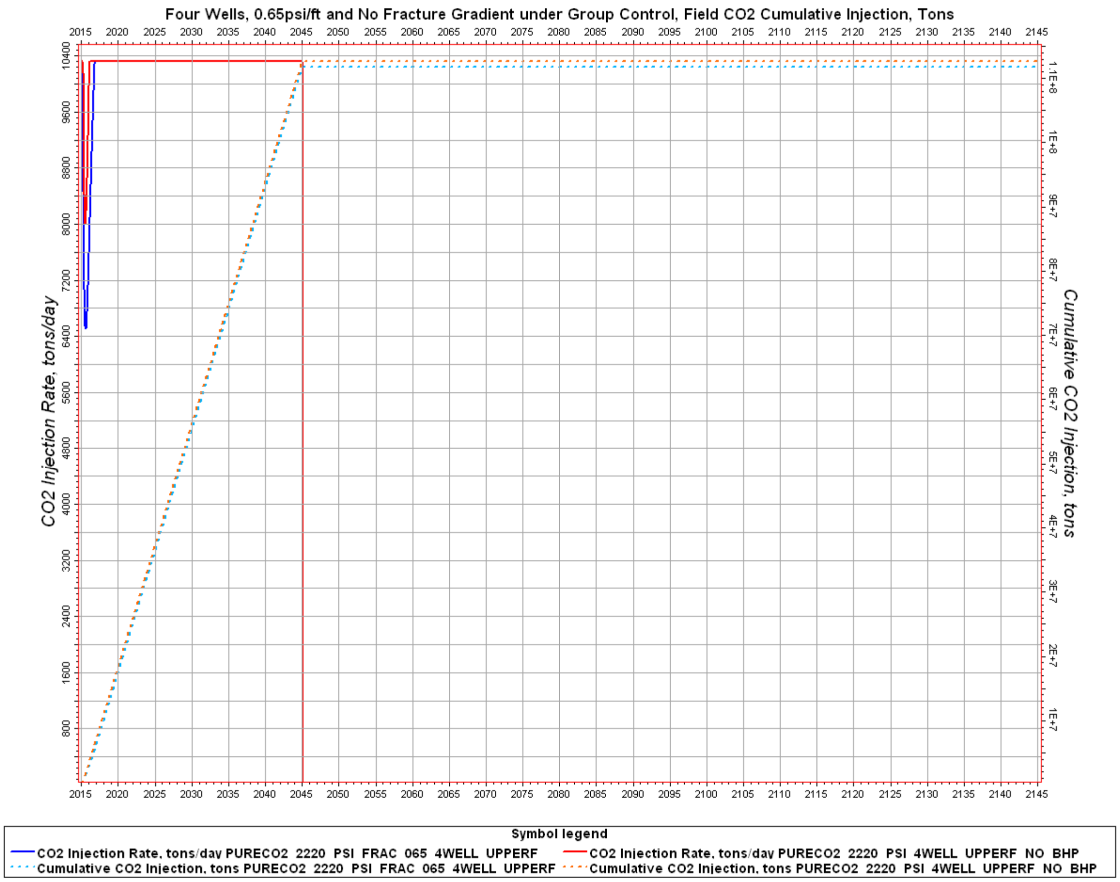

Figure 9 - Field injection rate and cumulative injection for the 4 Well Case with a 0.65psi/ft fracture gradient and without any BHP constraints.

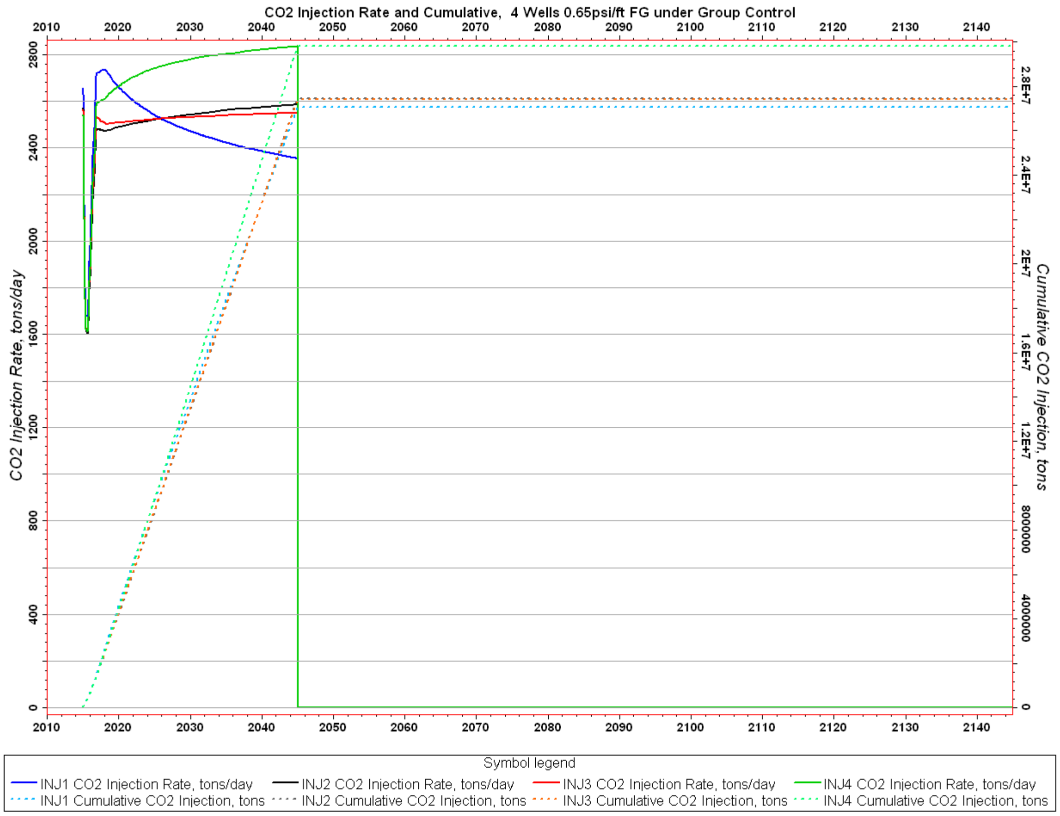

Figure 10 - The injection profile for each well. The 4 Well Case is capable of handling the full expected injection capacity.

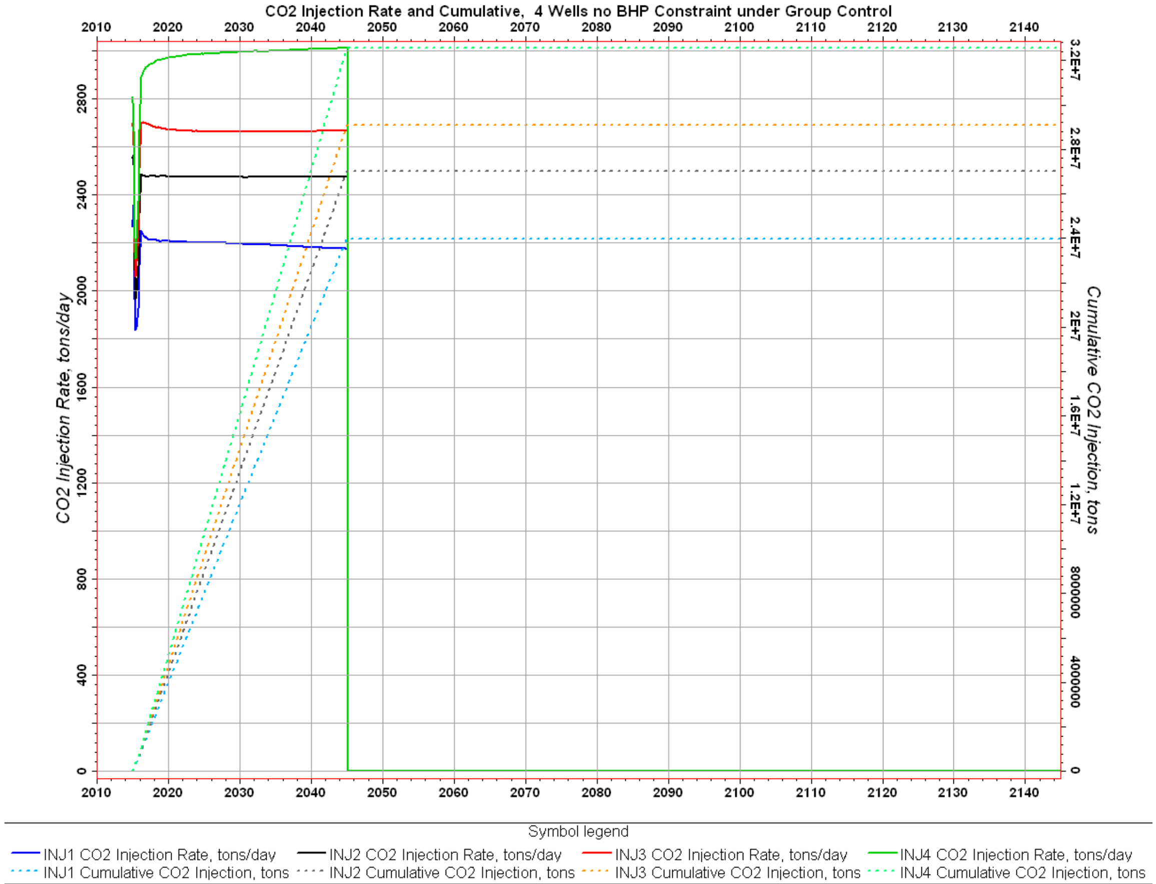

Figure 11 - The injection profile for each well. The 4 Well Case with no BHP constraint reaches full injection capacity at the fasted rate of the vertical well cases.

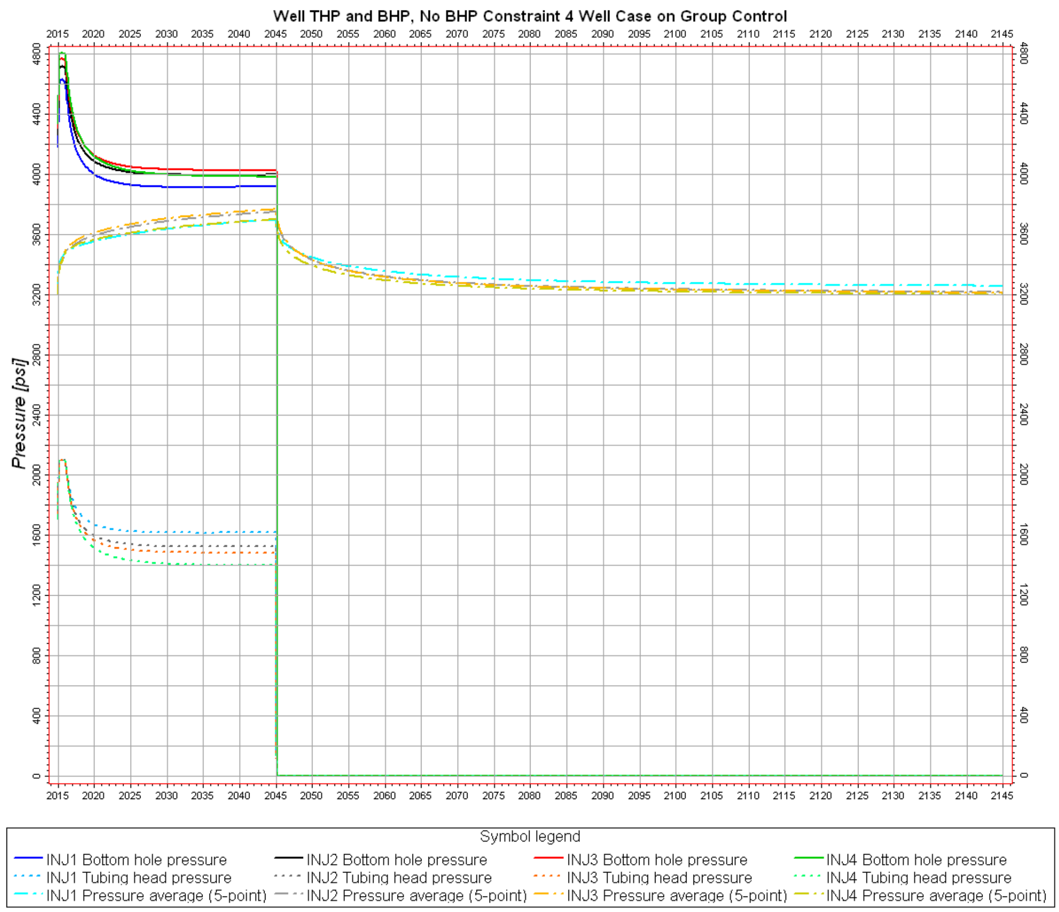

Figure 12 - The injection profile plots for each well for BHP, THP and near wellbore reservoir pressure for the 4 Well Case with no BHP constraint.

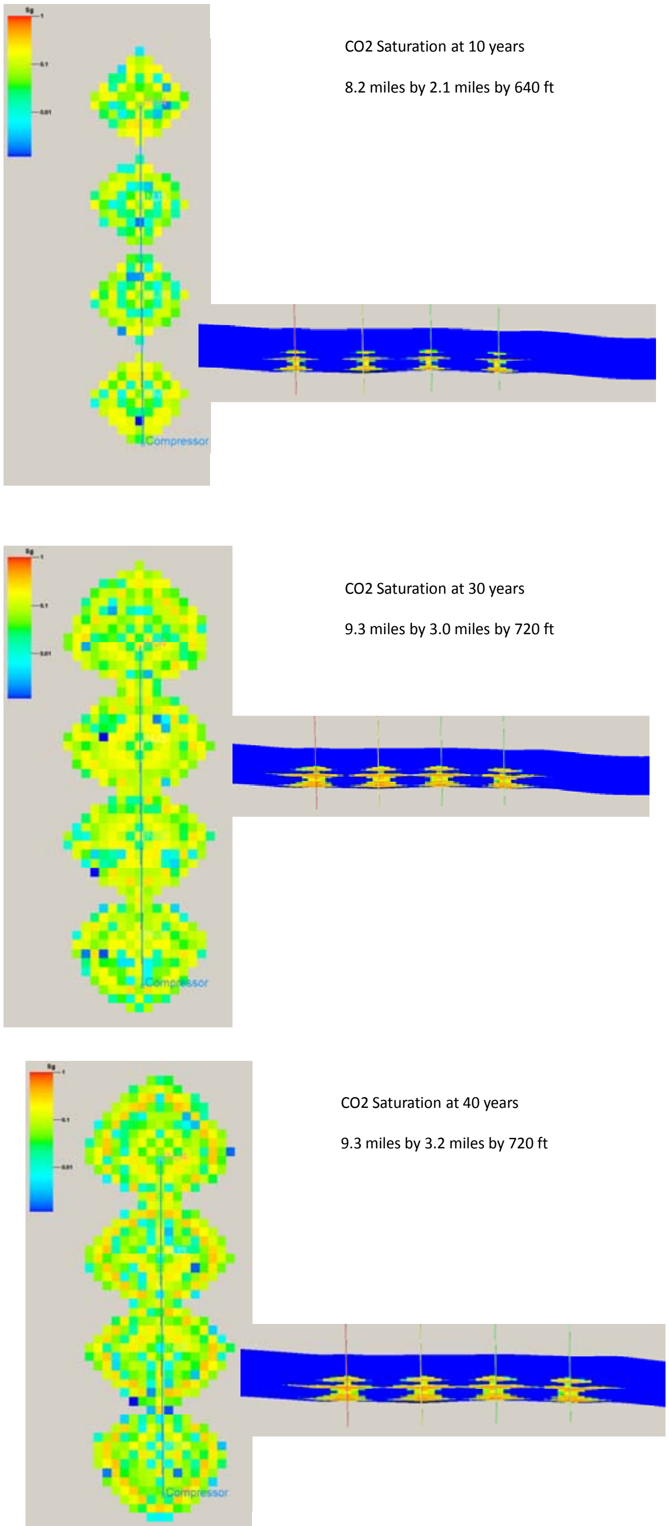

Figure 13. CO_2 Saturation over 40 years for the four well case

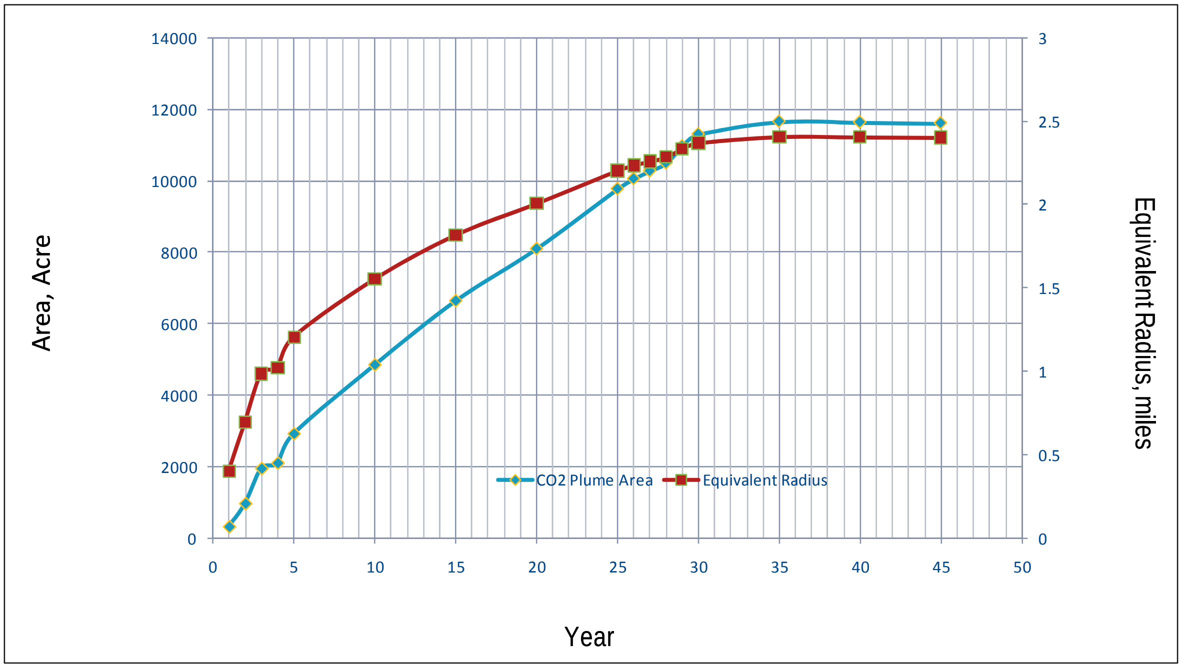

Figure 14 - CO_2 Plume Area

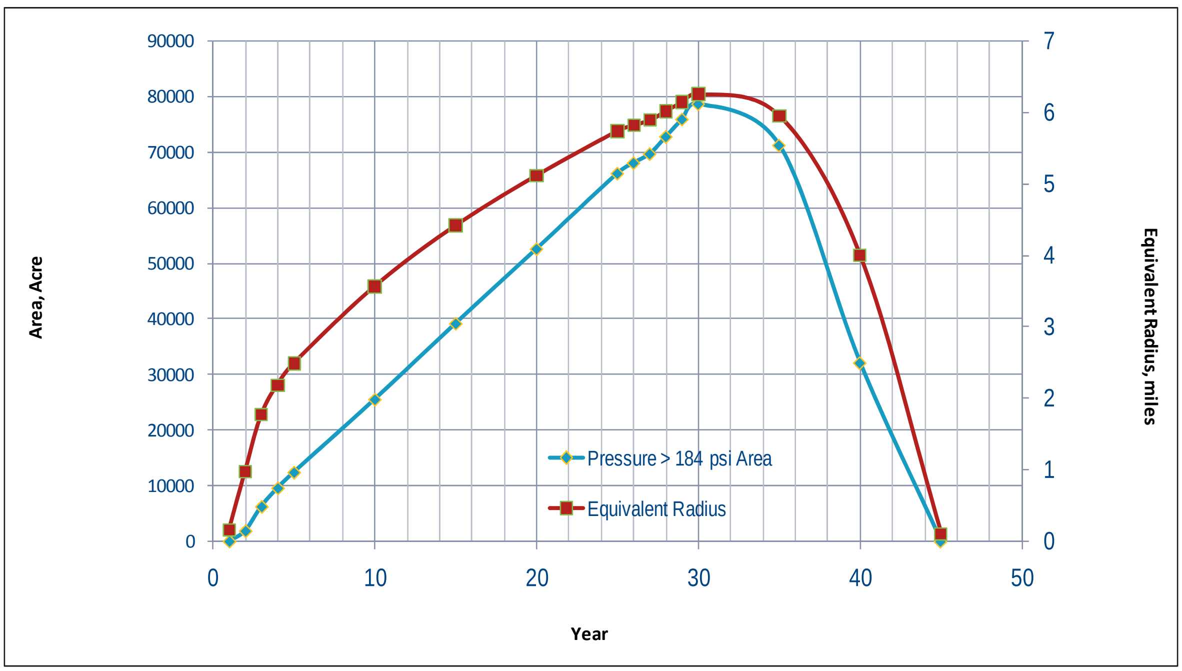

Figure 15 - Pressure Pulse Area (Pressure >180 psi)

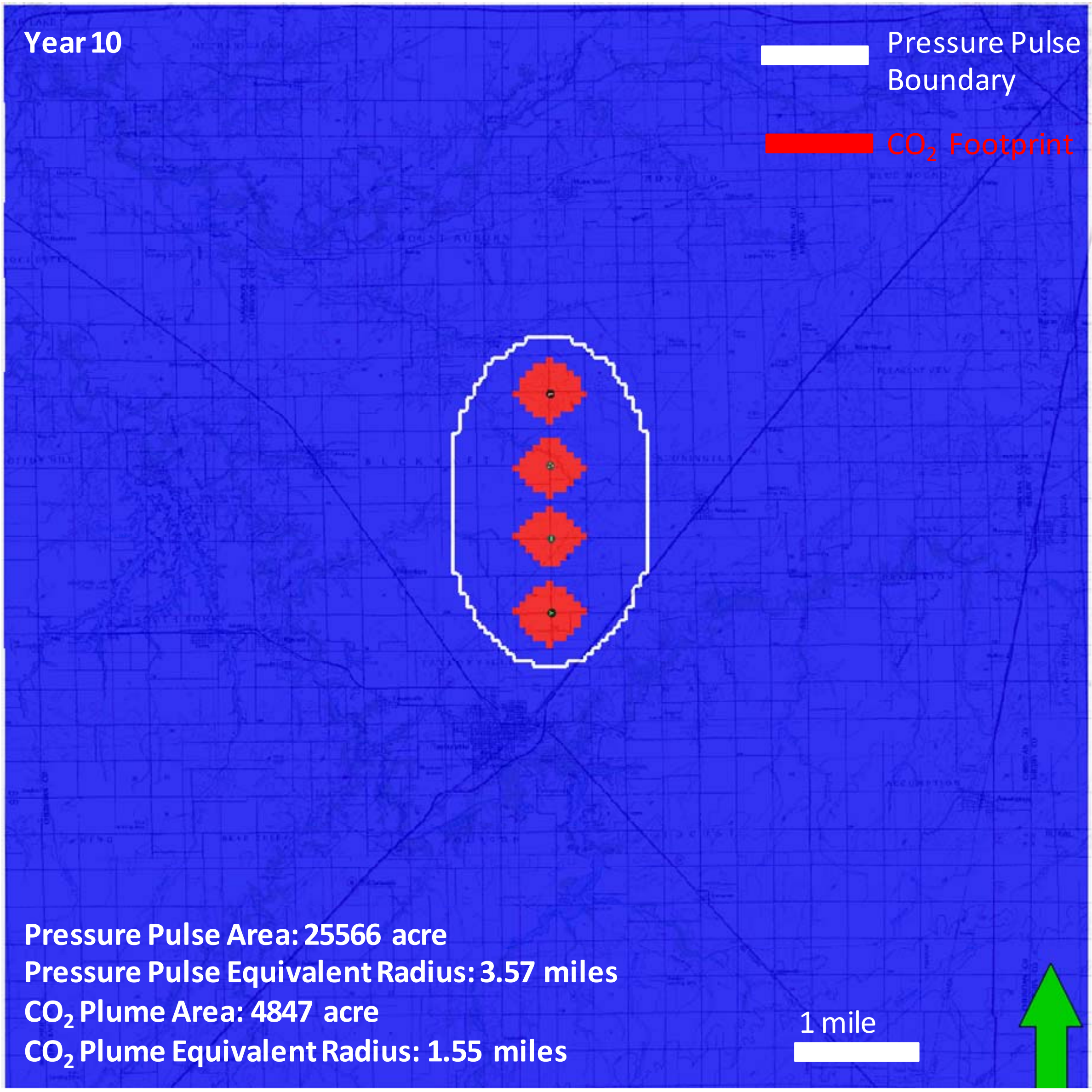

Figure 16 - CO_2 Foot Print and Corresponding 180 psi Pressure Pulse

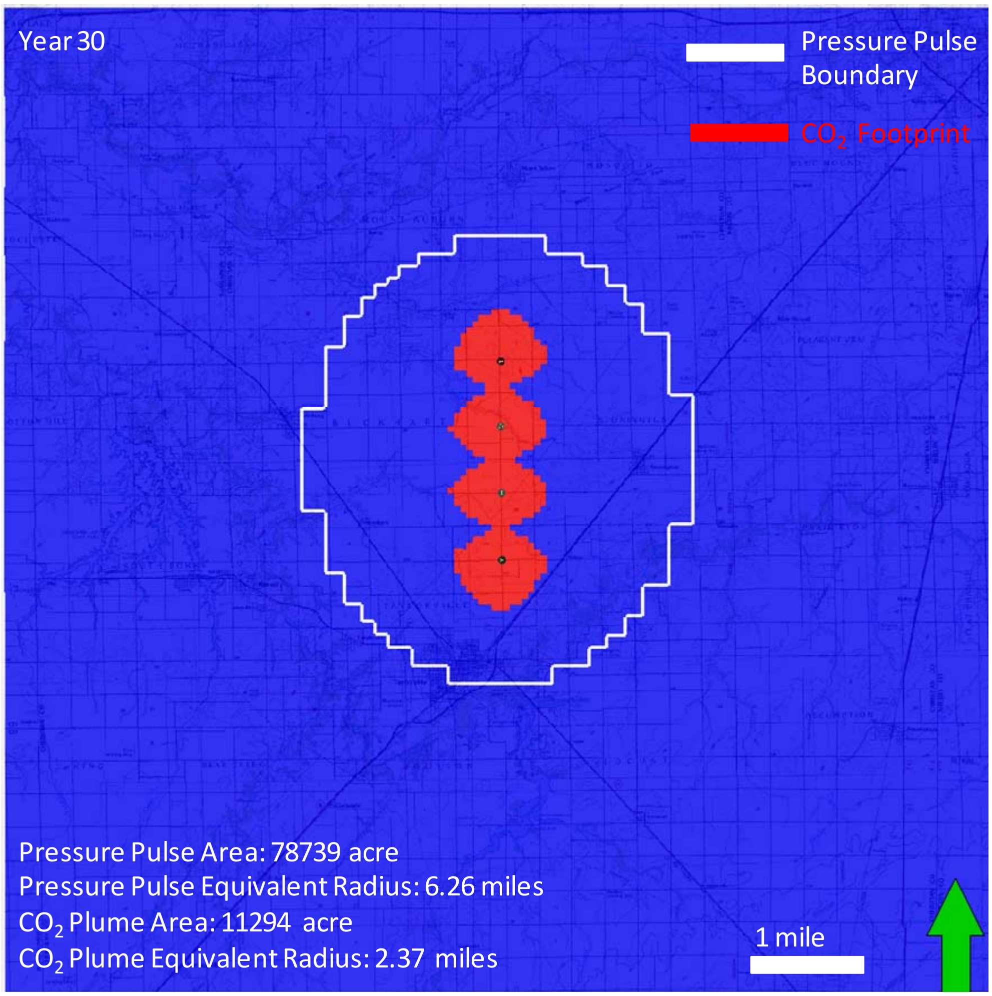

Figure 17 - CO_2 Foot Print and Corresponding 180 psi Pressure Pulse

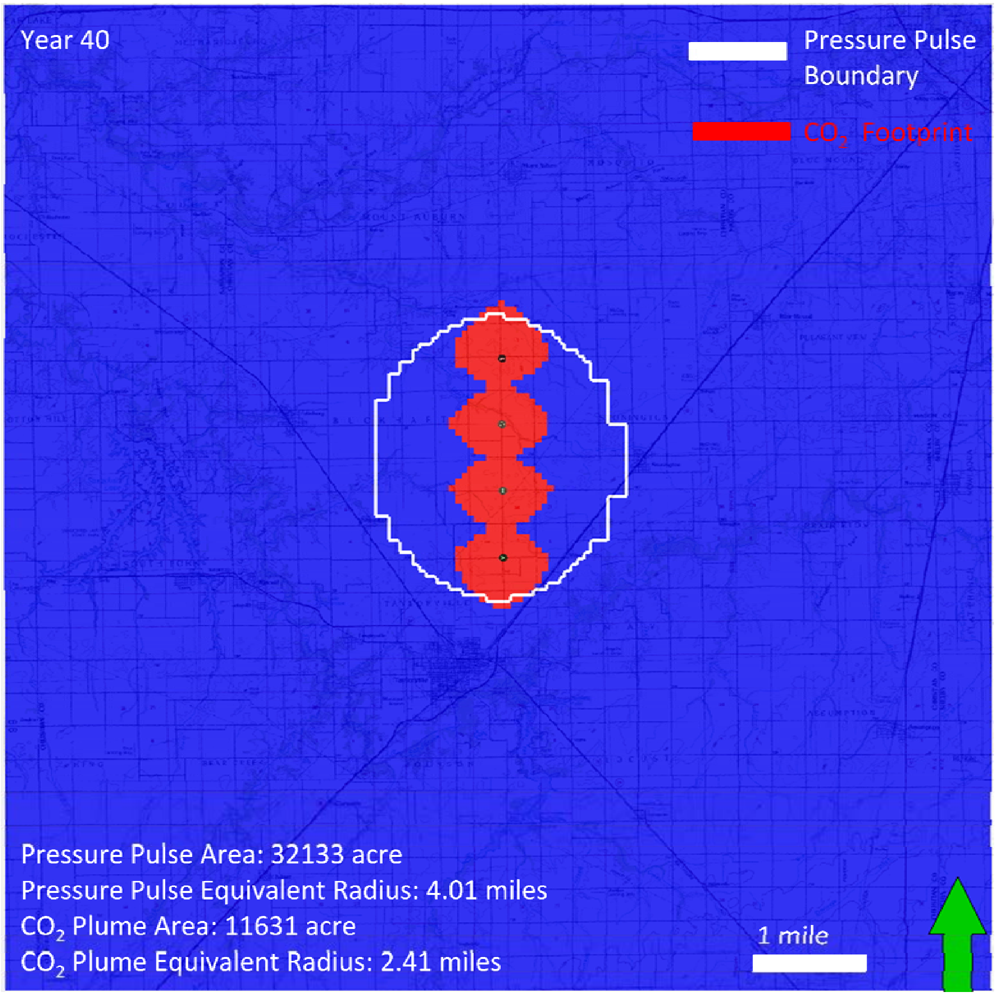

Figure 18 - CO_2 Foot Print and Corresponding 180 psi Pressure Pulse

8.0 Corrective Action Plan and Schedule

There are no known existing or abandoned wells within the AOR that penetrate the Mt. Simon reservoir or the Eau Claire primary caprock. Therefore, no corrective actions are planned for the project area.

9.0 Area of Review Reevaluation Plan and Schedule

9.1 Reevaluation Strategy

The Area of Review (AOR) in the subject permit application is based on available regional and site geological information. Once the initial injection well is drilled, the geologic and reservoir models will be updated and the AOR reevaluated. If necessary, the AOR and Corrective Action Plan will be revised.

9.2 Proposed Reevaluation Cycle

The AOR will be reevaluated every five years following issuance of the UIC permit by US EPA. Other conditions which could occur at or outside of the five year cycle, and which would cause a reevaluation of the AOR include:

- Significant changes in site operations that may alter model prediction and the AOR delineation.
- Monitoring results for the injected CO_2 and/or the associated pressure front at the site differ significantly from model predictions, or
- New site characterization data is obtained that may significantly change model predictions and the delineated AOR.
- New deep wells within the AOR

At this time, there are known or suspected sit-specific criteria that would trigger AOR reevaluation.

Following each AOR re-evaluation, a report will be prepared documenting the re-evaluation process, data evaluated, any corrective actions determined necessary, and the schedule for any corrective actions to be performed. The report will be submitted to US EPA for approval within a timeframe specified by permit.

If no changes result from the re-evaluation, the report will include the data and results demonstrating that no changes are necessary.

*Mark of Schlumberger

Attachments

Plate 1 AOR and Significant Site Features

Table A-1 Summary table of wells in AOR

Symbol	Description	Count
◆	Confidential	96
×	Coal Test	45
◆	Dead Permit	28
◆	Dry Hole	3
◆	Dry Hole (water well), Plugged	2
◆	Dry and Abandoned, No Shows	8
◆	Dry and Abandoned, No Shows, Plugged	245
◆	Dry and Abandoned, Oil Shows	1
◆	Dry and Abandoned, Oil Shows, Plugged	4
×	Engineering Test	12
◆	Mine Shaft	2
◆	Oil Producer	63
◆	Oil Producer, Plugged	187
◆	Permit to Drill Issued	6
◆	Salt Water Disposal, Service Well	5
◆	Salt Water Disposal, Service Well, Plugged	10
×	Structure Test	2
×	Structure Test, Plugged	5
◆	Temporarily Abandoned	10
◆	Temporarily Abandoned, Oil Shows	1
◆	Temporarily Abandoned, Oil Shows, Plugged	1
◆	Temporarily Abandoned, Plugged	3
◆	Unknown	8
◆	Unknown, Plugged	1
◆	Water Injection Well	2
◆	Water Injection Well, Plugged	2
◆	Water Supply Well, Plugged	1
◆	Water Well	297
◆	Water Well Monitoring Well	4
×	Water Well Test Hole	43
	Total Count	**1097**

Table A1 Summary Table of wells in AOR

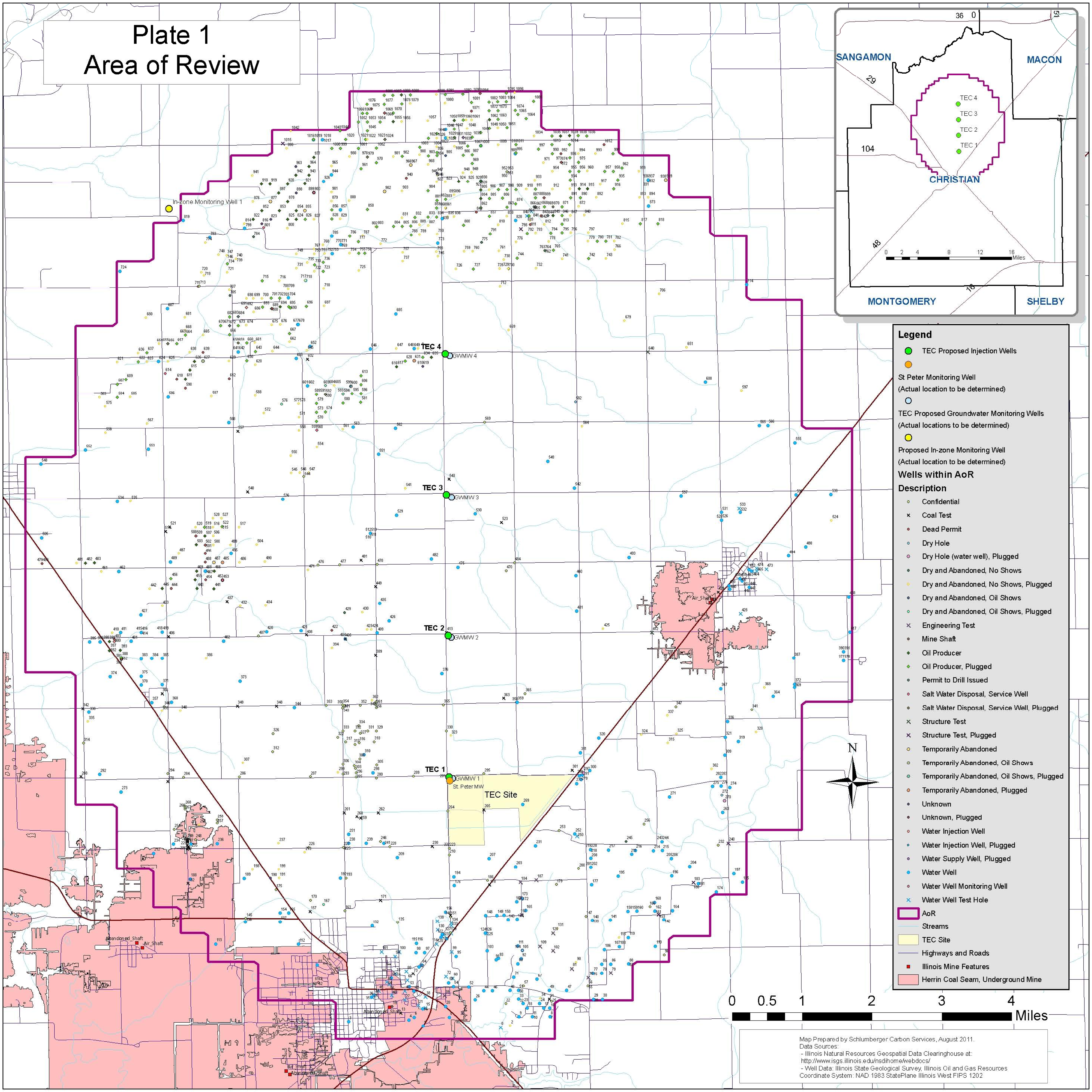

Plate 1
Area of Review
SANGAMON
MACON
CHRISTIAN
MONTGOMERY
SHELBY
TEC 4
TEC 3
TEC 2
TEC 1
In-zone Monitoring Well 1
GWMW 4
GWMW 3
GWMW 2
GWMW 1
St. Peter MW
TEC Site
Legend
TEC Proposed Injection Wells
St Peter Monitoring Well
(Actual location to be determined)
TEC Proposed Groundwater Monitoring Wells
(Actual locations to be determined)
Proposed In-zone Monitoring Well
(Actual location to be determined)
Wells within AoR
Description
Confidential
Coal Test
Dead Permit
Dry Hole
Dry Hole (water well), Plugged
Dry and Abandoned, No Shows
Dry and Abandoned, No Shows, Plugged
Dry and Abandoned, Oil Shows
Dry and Abandoned, Oil Shows, Plugged
Engineering Test
Mine Shaft
Oil Producer
Oil Producer, Plugged
Permit to Drill Issued
Salt Water Disposal, Service Well
Salt Water Disposal, Service Well, Plugged
Structure Test
Structure Test, Plugged
Temporarily Abandoned
Temporarily Abandoned, Oil Shows
Temporarily Abandoned, Oil Shows, Plugged
Temporarily Abandoned, Plugged
Unknown
Unknown, Plugged
Water Injection Well
Water Injection Well, Plugged
Water Supply Well, Plugged
Water Well
Water Well Monitoring Well
Water Well Test Hole
AoR
Streams
TEC Site
Highways and Roads
Illinois Mine Features
Herrin Coal Seam, Underground Mine
N
0 0.5 1 2 3 4 Miles
Map Prepared by Schlumberger Carbon Services, August 2011.
Data Sources:
- Illinois Natural Resources Geospatial Data Clearinghouse at:
http://www.isgs.illinois.edu/nsdihome/webdocs/
- Well Data: Illinois State Geological Survey, Illinois Oil and Gas Resources
Coordinate System: NAD 1983 StatePlane Illinois West FIPS 1202

Testing and Monitoring Plan

1.0 Facility Information

Facility Name: Taylorville Energy Center

Applicant Name: Christian County Generation, L.L.C., 1044 N 115 St., Suite 400, Omaha, NE 68154-4446

Facility Contacts: Ryan Choquette, Manager, Midstream Engineering, Ph. 402-938-1641, e-mail rchoquette@tenaska.com

Location: 1630 N 1400 E Road, Taylorville, Christian County, IL 62568

1.1 CO_2 Injectate

The proposed CO_2 injectate is derived and captured from the coal gasification process. The proposed power plant will be a 730-megawatt gross (500-megawatt net) electric generation facility using an Integrated Gasification Combined-Cycle design, or IGCC. The CO_2 source will be from the TEC IGCC coal gasification process.

1.1.1 Volume of Injection Fluid Generated Daily and Annually

Annual CO_2 injection for all wells could be up to 4,500,000 metric tons/year. Expected annual injection, based on current, preliminary plant design, is approximately 2,100,000 metric tons/year, assuming 92% availability under normal plant operations. Expected daily injection, per well is expected to range from 3,000 to 5,750 metric tons/day depending on site geology and injectivity. A flow meter will be installed to produce a direct reading of total volume per time of CO_2 being injected. Location will be after compression, but prior to well head.

1.1.2 Carbon Dioxide Stream Analysis

The CO_2 produced by the plant, which is over 98% pure, would be compatible with the existing formation fluid (brine or native formation saltwater that is several times saltier than sea water). The CO_2 will be captured, compressed to a supercritical phase, and transported to the injection wells. The following table represents the expected chemical composition of the TEC carbon dioxide product. The values in the table are based on the projected wellhead maximum pressure and temperature conditions of 2,220 psig and 120° F, respectively. Characteristics of the CO_2 injection fluid could vary significantly at different locations in the compression and dehydration process and seasonally with changes in ambient temperature. Additionally, the wellhead pressure of 2,200 psig is used for preliminary design purposes and is dependent on final plant engineering design and construction.

Note that some variations are possible due to site-to-site and day-to-day conditions:

Gas Composition %Mol			
Compound	**Normal**	**High**	**Low**
CH_4	trace	100 ppmv	0
CO	0.56 mol%	3 mol%	0
CO_2	98.38 mol%	100 mol%	92 mol%
COS	trace	100 ppmv	0
H_2	0.61 mol%	2.0 mol%	0
H_2O	trace	0.07 mol%	0
H_2S	10 ppmv	100 ppmv	0
MEOH	0.07 mol%	0.1 mol%	0
NH_3	trace	0.2 mol%	0
N_2	0.36 mol%	5.0 mol%	0
O_2	trace	100 ppmv	0
NO	trace	100 ppmv	0
NO_2	trace	100 ppmv	0
SO_2	trace	100 ppmv	0
$S0_3$	trace	100 ppmv	0
AR	0.01 mol%	0.3 mol%	0
Sulfur	trace	10 ppmv	0
Hg	trace	400 ppbv	0
Flash Point	none	none	None
Organics	0.07 mol%	--	--
TDS	N/A	N/A	N/A
pH	N/A	N/A	N/A
Temperature	80-90 ° F	40 ° F	120 ° F

1.1.3 Sampling Frequency

The CO_2 stream will be sampled quarterly (Table 1).

1.1.4 Analytes and Analytical Method

The sample will be sent to a commercial laboratory for analyses including:

- CO_2 Purity (% mol by Gas Chromatography)
- Non-Condensable Gases
- Hydrogen (H_2, % mol, by Gas Chromatography)
- Oxygen + Argon (Ar + O_2, % mol by Gas Chromatography)
- Nitrogen (N_2, % mol by Gas Chromatography)
- Carbon Monoxide (CO, % mol by Gas Chromatography)
- Methane (CH_4, ppm by Gas Chromatography):
- Methonal (MEOH % mol by Gas Chromatography)
- Hydrogen Sulfide (H_2S ppm by Gas Chromatography)
- Total Sulfur Content (ppm by Gas Chromatography)

The sample will be tested using ASTM 5954 and ASTM 6228 or ASTM 5504 or equivalent procedures.

1.1.5 Sampling Method

The gas sampling will be conducted downstream of the CO_2 compressor using a lined sample bottle. The gas sample will be send to an independent lab to be tested. The exact locations and details of the sampling location will be provided as more design details are finalized.

1.1.6 Laboratory to be Used/Chain of Custody Procedures

A commercial laboratory will be selected to do the analyses. At this time, the laboratory has not been identified. The laboratory will be capable of meeting the testing methods and procedures as noted above.

Each sample will be logged on a sampling form and will document the chain of custody. The form will note:

- Sampling date
- Location the sample was collected
- Type of container
- Sampler name and signature
- Other comments/notes
- Shipping information (name, address, and point of contact at laboratory, including phone number)
- Laboratory received by name and signature.

1.1.7 Quality Assurance and Surveillance Measures

The sample integrity and security will be documented through maintenance of a field sampling record and by use of the Chain of Custody form. The laboratory will provide, upon request, documentation of instrument calibration. The laboratory report will include the analytical results as well as reporting detection limits established for each method. The laboratory report will also include a copy of the completed Chain of Custody form.

1.2 Continuous Recording of Injection Pressure, Rate, and Volume

1.2.1 Surface Facilities, CO_2 Pipelines

Continuous supervisory control and data acquisition (SCADA) monitoring will occur in the CO_2 capture process area of the facility and extend from the CO_2 pipeline system to the individual injection wells. Continuous monitoring of injection flow rate, pressure and temperature will occur throughout the system. A schematic of the process and instrumentation diagram showing proposed system is attached (Figure 1)

1.2.2 Injection Wells

The current design of TEC's MVA program includes flow meters and pressure gauges at each injection well (Figure 2) to measure and record the volume of CO_2 and fluid that is injected into the Mount Simon Sandstone formation and continuously monitor the surface injection pressure to remain compliant within permit limits and provide an operating margin of safety below fracture pressure.

At the TEC injection wells, continuous monitoring will occur at the well annulus system, well head and surface piping. Before the well head is equipment will be installed to measure and record in real-time injection parameters such as injectate temperature, surface or wellhead injection pressure, using a meter to record flow rates. This will monitor system performance, and provide injection verification and accounting, also be used to optimize injection operations.

1.2.3 Annulus Pressure

The annular pressure will be continuously monitored at the surface and downwell, above the packer to detect anomalies or changes (Figure 2). The annulus will be filled with a corrosion resistant fluid. The annular pressure will be monitored to evaluate potential leakage through the injection tubing, casing or around the injection packer. Additionally, a set of operating limits or a minimum-maximum pressure range would be employed within a sensitive enough range to react to identified pressure losses. TEC proposes using annulus pressure monitoring limits set at -5.0 psi to +50 psi. If there is an identified leak in the production casing, fluid would be lost from the annulus and a negative pressure would be observed. If a leak is present in the tubing, a positive pressure deflection would be observed. Anomalies can be suggestive of potential fluid leaks that could develop in either the injection tubing or the production casing or be associated with thermal effects. This operating range is set to reduce false alarms resulting from other variations in operating conditions such as thermal effects and continuously monitor and record values. See Section 4.16 of the Technical Report for more details on the rationale and design of the annular monitoring system.

1.3 Ground Water Quality Monitoring

The CO_2 injection well field will contain up to four shallow observation wells consisting of one completion near each injection well. The shallow wells will be set into the identified fresh water aquifers to monitor fluids for potential vertical CO_2 migration from deeper injection intervals. These observation wells would be situated at shallow depths of < 300 feet, and completed in the glacial outwash, the primary source of potable groundwater in the area. The outwash zones can occur anywhere within the glacial sediments which are approximately 100 feet thick in the area and are present over 4,500 feet shallower than the deep Mount Simon injection interval at 5,115 feet. The monitoring wells are shown on Figure 3; exact locations are to be determined based on site conditions observed during injection well installation.

Engineering and plans for these observation wells will be designed to detect CO_2 migration, and leakage (Figure 4a). All groundwater monitoring wells will be installed and eventually abandoned according to

Illinois Department of Public Health regulations. Each proposed groundwater observation well will be constructed of Schedule 40 PVC casing and screen and will drilled to approximately 100 feet to encounter the freshwater intervals. Surface seals using cement or bentonite grout will be installed (Figure 4b). Each well would be secured with a locking surface “stick-up” to prevent tampering and with a minimum of three bollards to reduce the risk of surface damage due to vehicular traffic and vandalism. The ground surface elevation and an elevation measuring point will be surveyed and recorded for each well to the nearest 0.1 feet above mean sea level

The shallow groundwater monitor wells will be adjacent to injection wells. A preliminary sampling and analysis proposed schedule includes monitoring initially on a quarterly frequency for at least one year, prior to start up of the injection system to establish baseline conditions. Thereafter, monitoring is planned to occur on quarterly basis throughout the life of the CO_2 injection phase and into the post-injection phase. Then, after five years post-injection, sampling and reporting will be completed annually until site closure. The planned analyses include field pH measurements; fluid quantitative laboratory analyses include major cations and anions, and select trace metals as indicators of injectate reaction products or reactions.

Groundwater parameters include:

Field Parameters	**Reporting Units**
Ph	
Specific Conductance	Micromos/cm
Sample Temperature	^{o}F
Dissolved Oxygen	Mg/L
Depth to Water (below land surface)	Feet
Depth to Water (below measuring point)	Feet
Elevation of Groundwater Surface	Ft above mean sea level (MSL)
Elevation of Bottom of Well (measured once per year)	Ft MSL
Elevation of Measuring Point (e.g. top of casing surveyed every other year)	Ft. MSL
Indicator Parameters	**Reporting Units**
Alkalinity	Mg/L
Bromide	Mg/L
Calcium	Mg/L
Chloride	Mg/L
Sodium	Mg/L
Total CO_2	Mg/L

1.3.1 Sampling Methods

Prior to installing the injection wells, TEC plans on obtaining background groundwater, water well samples, which will enable a level of comparison with future collected samples. The goal is to be able to collect these samples as pre-project background or baseline samples and later return on a periodic frequency to sample the same locations at various key points throughout the project. The sampling plan is to collect quarterly samples for at least one year prior to injection to establish USDW quality baseline. Baseline and routing monitoring samples will be field analyzed for pH, conductivity, temperature, dissolved oxygen and submitted to an analytical laboratory for the following major constituents: Alkalinity, Bromide, Calcium, Chloride, Sodium, total CO_2.

At the time of sampling, water levels will be measured and recorded and the volume of water in the well will be determined. Each monitoring well will be purged using a submersible pump, hand-bailer, or other lift pump. At least three well volumes will be purged prior to sampling. Samples will be collected using a hand bailer or pump and dispensed into cleaned containers provided by the analytical laboratory. All sample containers will be new. Samples will be field preserved as required by the analytical method.

Sample preservation and containers

ANALYTE	PRESERVATION[1]	HOLDING TIME[1]	CONTAINER[1]	METHOD
Alkalinity	Filtration, 4° C	In field, 14 days	HDPE bottle	EPA 310.1 APHA[2] 2320
Dissolved Anions: Bromide, Chloride	Filtration, 4° C	28 days	HDPE bottle	EPA 300.0 APHA 4110B
Dissolved Metals: Calcium, Sodium	Filtration, 4° C, HNO_3 < pH 2	6 months	HDPE bottle	EPA 200.8 APHA 3120B
Total CO_2	Filtration, 4° C	14 days	HDPE bottle	APHA 4500-CO_2D Orion, 1990 or ASTM D513-06

Note 1: USEPA, Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020
Note 2: American Public Health Association (APHA), Standard Methods for the Examination of Water and Wastewater

1.3.2 Analytical Techniques

Anion concentrations will be determined by ion chromatography (EPA Method 300.0), and cation concentrations will be determined by inductively coupled plasma (ICP) spectrophotometry, (e.g., EPA

Method 200.8; APHA, 2005). Alkalinity will be determined using APHA Method 2320. Total CO_2 concentrations will be determined preferentially by coulometry per ASTM D513-06 or alternatively by other methods (e.g., Orion, 1990; APHA, 2005).

1.3.3 Laboratory to be Used/Chain of Custody Procedures

A commercial laboratory will be selected to do the analyses. At this time, the laboratory has not been identified. The laboratory will be capable of meeting the testing methods and procedures as noted above.

Each sample will be logged on a sampling form and will document the chain of custody. The form will note:

- Sampling date
- Location the sample was collected
- Type of container
- Sampler name and signature
- Other comments/notes
- Shipping information (name, address, and point of contact at laboratory, including phone number)
- Laboratory received by name and signature.

1.3.4 Quality Assurance and Surveillance Measures

Standard methods will be followed for sample handling and analyses. TEC will develop system-wide QA plans and surveillance measures as part of the plant operations and maintenance procedures and planning. These plans will be developed in detail once TEC #1 is drilled and injectivity and storage are verified. Field quality assurance will primarily include periodic field duplicates and field blanks. One field duplicate and one field blank will be used per sampling event. Additional field QA/QC measures will be implemented according to ASTM Method D7069-04 (2004) as needed based on data analysis of historical results and laboratory performance during the monitoring program.

Where appropriate, ASTM Method D6911-03 (2003) will be followed for packaging and shipping of samples. Immediately upon sample collection, containers shall be placed in an insulated cooler and cooled to 4 degrees Celsius. Samples will either be shipped or hand delivered. Shipment priority will be determined by the holding times or need to expedite sample analysis. Upon receipt at the laboratory, the samples will be accepted and tracked by the laboratory from arrival through completed analysis.

Data validation will include the evaluation of the concentration units, sample holding times, method and field blanks, and field duplicates. Analytical results from the contract analytical laboratory will be provided electronically and/or in hard copy. All of the groundwater quality data will be entered into a database or spreadsheet with QA/QC review to insure no data entry errors. The data will be presented in tabular form and will be sorted by well, type of constituent, and/or time of sampling. Copies of any reports from the contract analytical laboratory will also be on file and provided to US EPA upon request.

TEC is proposing to use the Shewhart-CUSUM control charts to evaluate the concentrations of each groundwater constituent within each well over time and to identify significant changes that could be the result of CO_2 seepage (US EPA, 2009).

Data will also be evaluated graphically (bar charts, XY charts, box plots, and/or tri-linear diagrams) to help in visualization of the areal distribution of water quality constituents, identifying changes in water quality with time, and comparing water of different composition.

Compliance will be assessed through the use of Shewhart control charts for each monitored constituent. An example is provided in Figure 5 where a monitored concentration of a constituent has initially been within the Ground Water Protection Standard's limit. However, after some time the constituent has surpassed the limit. A response plan would be required in this case.

Within this graph, upper and lower control limits (i.e. UCL and LCL), or perhaps more pertinent, +/- 3 standard deviation lines can be shown based on the pre-compliance monitoring phase. In the absence of a GWPS, or when GWPS greatly exceeds constituent concentration, the control limits would help reveal whether the measured concentration of a constituent has diverged from the original, baseline population.

Initial water quality values from the first year of monitoring will be considered the nominal baseline. In fact, the baseline statistics should also inherit the natural variability due to the changes in the seasons as this can affect groundwater chemistry. Thus, preceding the injection period, a baseline mean and standard deviation will be computed for each constituent. Control limits will be computed and will serve as the criteria for which to assess a significant deviation from the baseline population mean.

Once CO_2 injection commences, compliance monitoring will go into effect. A constituent's concentration will be considered statistically significant different if it falls outside +/- 3 standard deviations or if it increases for four consecutive sampling rounds. Furthermore, exceedance of the GWPS will initiate a response to investigate the cause of the change including:

- Pipeline evaluation to check for leaks
- RST well log
- Review area for other sources external to the project

Once the source has been identified, corrective measures will be developed and implemented.

1.3.5 Plans for Guaranteeing Access to all Monitoring Locations

Property has been optioned for TEC #1 at the plant site and TEC #3 four miles north of the plant site. Additional agreements for TEC #2 and TEC #4 will be executed contingent on final permitting, approval, funding for the TEC project, and test results for TEC #1. The shallow monitoring wells will be installed on the same parcel as the injection wells. The wells will be separated by up to several hundred feet to avoid damage to either the injection well or the monitoring well and to assure safe access to each well for operations and maintenance.

1.3.6 Deep St. Peter Observation Well

Upon completion of the initial injection well, TEC will plan final well site selection of a deep St. Peter Sandstone observation well as part of its on-site Monitoring Program. The location for the proposed 3,400 foot well will be adjacent to TEC #1 but is not final. The actual location is pending the results and testing of the initial injection well #1 and final surface design and other constraints associated with the TEC facility development. A preliminary well design has been prepared and included as Figure 6 for this St. Peter observation well. Depending on the results of well log analysis from the TEC #1-injection well, the St. Peter Sandstone horizon will be perforated and completed to monitor the interval via downhole pressure-temperature sensors in a packer-tubing-annulus system. Periodic sampling of St. Peter Sandstone interval formation fluids will occur to detect potential changes to the background sample set.

The well will provide an indication of pressure effects and assist in the reservoir model predictions.

1.3.6.1 St. Peter Sandstone Deep Observation Well Rationale and Design Basis

Within the Taylorville area, the St. Peter sandstone is not developed as a potable, agricultural, or industrial water supply source in the project area. The St. Peter sandstone has in fact been used in the region for fluid disposal. However, some geologic, reservoir and salinity data are available from limited wells and show that total dissolved solids (TDS) in the St. Peter Sandstone are close to 10,000 mg/l, which places it near the regulatory maximum USDW threshold limit as set by the agency.

To be protective and conservative of potential USDWs, TEC as a result of detailed site development and monitoring plans is proposing installation of the St. Peter Sandstone observation or monitoring well in association adjacent to TEC #1. A final location has not been selected and will be provided to US EPA upon completion of the drilling of TEC #1-injection well.

A preliminary well design proposed by TEC for the St. Peter Sandstone observation well, engineers and installs two separate strings of carbon steel casing, using standard metallurgy and well installation methods for the completion (Figure 6). Well monitoring instrumentation consists of a packer and downhole and surface pressure gauge consisting of real-time measurements with continuous surface data recorders to monitor pressure and temperature. TEC is proposing that the observation well be installed and completed with the following well construction parameters:

1. A 400-foot section of 9-5/8-inch surface casing will be set and cemented to surface in a 12-1/4-inch borehole and,
2. Approximately 3310 feet of 5-1/2-inch production casing would run from TD to surface.

The continuous record of recorded pressure and temperature data can show the effects and trends associated with potential anomalies and may be used to identify vertical leakage of CO_2. Initial plans are for data to be transmitted and connected to the TEC plant site system control and data acquisition (SCADA) network.

1.3.6.2 St. Peter Sandstone Monitoring Frequency

The St. Peter observation wells will be accessed periodically to collect formation fluid samples following a fluid sample monitoring protocol to be developed by TEC and provided to US EPA upon determination of the salinity and TDS values in the St. Peter Sandstone. A preliminary sampling and analysis proposed schedule includes:

- One baseline sample (pre-injection)
- Annual through the injection phase

Analysis of the recovered St. Peter fluid samples will include gas-water ratio, ionic composition, pH, and analyses required for correction to account for mud filtrate.

1.3.6.3 St. Peter Sandstone Potential Deep USDW

Upon drilling and testing TEC #1-injection well, if the St. Peter Sandstone consists of water at less than 10,000 mg/l TDS, TEC will be conservative and protect this potential deep USDW source with the 13-3/8-inch casing section, and insure continuous cement is present across the interval and isolation above and below are assured via cement bond log evaluation. As a direct comparison of salinity, the Mount Simon Sandstone injection reservoir salinity is expected to contain over 100,000 ppm TDS, which is greater than 3 times the salinity of sea water.

1.3.6.4 Sampling Plan Summary

A detailed sampling plan will be developed for this well after completion and will be based on observed site conditions. In general:

1. Sampling Methods - samples will likely be collected using a wireline formation tester (e.g. MDT* modular formation dynamic tester).
2. Analytical Techniques – it is expected that analytes and methods will be similar to those used for the sallow groundwater (USDW) samples.
3. Laboratory to be Used/Chain of Custody Procedures – the laboratory will be identified at the time the monitoring plan is updated (following completion of TEC #1). Similar sample chain of custody forms will be used throughout the project.
4. Quality Assurance and Surveillance Measures – final QA program is to be established but will be similar to the program developed for the shallow groundwater sampling.
5. Plans for Guaranteeing Access to all Monitoring Locations – the well will be located on TEC property near TEC #1.

1.4 External Mechanical Integrity Tests

Following drilling and completion of the well, TEC will perform another monitoring inspection, a Mechanical Integrity Test (MIT), which is performed as a specified condition of the permit and documents cement bond log quality, identifying vertical isolation as continuous or sufficient in aggregate intervals to protect the lowermost USDW. TEC plans on using EPA Region 5 MIT guidelines for testing of the wells. In addition, cement bond log and corrosion inspection logs will be performed on a regular frequency (every five years) to identify if active corrosion or casing wall degradation is present. Any change to the baseline pre-injection operations cement quality can be identified from evaluating follow-up logs using a well log monitoring program. Additionally, pressure testing of the casing proves integrity of the cemented well completion to hold pressure in an annulus with negligible loss.

The injection wells will have periodic MIT performed to verify that no CO_2 is migrating out of the Mount Simon Sandstone injection interval, vertically through the well bore. Additionally, annulus pressure testing and the existence of a pressure monitoring annulus will record the integrity of the completion, specifically if leaks occur in:

a) the formation to cement area,

b) the cement to casing area,

c) the corrosion inhibited fluid-filled annulus, and

d) the injection tubing.

Cement bond logs will record the integrity of the cement bond and hydraulic isolation, while bottomhole pressure testing (shut-in) or offset well pressure values in the injection reservoir can provide a measure of the reservoir performance and future capability, or whether completion stimulation or acidization is required at perforations or the injection interval.

A fluid-filled annulus and pressure differential will provide a necessary record or trend line to determine anomalies and identify potential leaks.

Both of these tests (cement bond, and annulus pressure test) and the UIC requirements form the basis for US EPA to certify the well as sound construction with mechanical integrity. All MIT data will be submitted to US EPA upon completion of the well. Successfully passing MIT, and using proper well construction as reviewed by US EPA in the approved TEC plan in the Permit, allows US EPA to certify the well as ready for injection operations, authorizing initial injection to proceed. By performing MIT tests, TEC ensures that the well is properly constructed and exhibits integrity and provides key monitoring data showing the following:

- MIT Test (cement bond, casing pressure test) is protective of the lowermost USDW
- Annulus Pressure test provides important casing mechanical integrity results
- Ambient, continuous monitoring is present during and post injection
- Mitigation plan exists for potential leaks, etc.

1.4.1 Annual MIT

The annual MIT will be conducted, consisting of an Annulus Pressure Test (APT) and Bottomhole Pressure Falloff Testing. The APT will be done by pressuring up the annulus to 500 psi above atmospheric pressure and measuring fall off, under shut-in conditions for at least one hour. Loss of 5 psi or less over the shut in period will demonstrate mechanical integrity of the casing-tubing annulus which includes the wellhead, tubing, casing, and packer systems. Additionally, a program of corrosion coupon monitoring near the wellhead will be in place pending final design.

1.4.2 Other Mechanical Integrity Monitoring - Corrosion Monitoring

An internal corrosion monitoring program that meets ASTM requirements (Designation G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens) will be used on the pipeline and the injection wells. Weight loss coupons or electrical probes will be installed to monitor corrosion. Two coupons or probes will be installed at each injection well site. One coupon will be in the flow line. The other coupon will be located on the wellhead. The coupons will be held in place using industry standard coupon holders. The coupons will be monitored twice each calendar year, at intervals not exceeding seven and one half (7½) months. The coupons will be cleaned, inspected, and weighed per ASTM G1 standards. All weights will be taken with an accuracy of +/- 0.1 of a milligram. The weight will be recorded. The weight will be used to calculate the corrosion rate in mils/year. If the coupons are found to have more than 3 mils/year of loss, corrective action will be taken. Potential actions could include a review to verify no water is in the system and the use of corrosion inhibitors. When corrosion is over the 3 mils per year limit, the coupons will be monitored more frequently. Whenever a pipeline or tubing section is removed, an inspection of the internal surface of all pipelines for corrosion will occur. If extensive internal corrosion exists a review of the pressure capability of the pipe and tubing will be conducted. If the corrosion has reduced the wall thickness of a segment less than that required for the maximum allowable operating pressure, the pipe will be replaced or working pressure reduced.

1.5 Pressure Fall-Off Testing

A pressure falloff test will be conducted annually during injection to calculate the annual ambient average reservoir pressure.

At a minimum, a planned pressure falloff test will be preceded by one week of continuous CO_2 injection at relatively constant rate. The well will be shut-in or have reduced flows until adequate pressure transient data are measured and recorded to calculate the average pressure or for four days. The data will be measured using a surface readout downhole gauge so a real-time decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

1.5.1 Pressure Falloff Test Procedure

A pressure falloff test has a period of injection followed by a period of reduced or no-injection.

1.5.1.1 Pre-Injection Flow Period

Normal injection using the stream of CO_2 captured from the Taylorville facility will be used during the injection period preceding the shut-in (or reduced flow) portion of the falloff tests. Prior to the falloff test this rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. Injection will have occurred for 10-11 months prior to this test, but there may have been injection interruptions due to operations or testing. At a minimum, one week of relatively continuous injection will precede the shut-in (or reduced flow) portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in (or reduced flow) injection period and subsequent analysis. This data will be measured using a surface readout downhole gauge so a final decision on test duration can be made after the data are analyzed for average pressure. The gauges may be those used for day-today data acquisition or a pressure gauge will be conveyed via electric line (e-line).

1.5.1.2 Shut-in Period

The control valve located at the injection well will be used to reduce or stop flow of CO_2 to the wellhead nearly instantaneously with direct coordination with the injection compressor. Data will be collected at five second intervals or less for the entire test. The shut-in period will be until adequate pressure transient data are measured and recorded to calculate the average pressure or for four days. Since surface readout gauges will be used, the shut-in (or reduced flow) duration can be determined in real-time. A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the US EPA within 90 days of the test.

Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure fall off test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (.5% accuracy across full range). Downhole gauge range will be 0-10,000 psi.

1.6 Carbon Dioxide Plume and Pressure Front Tracking

To verify the “absence of significant fluid movement,” RST* reservoir saturation tool time-lapse sigma logs will be run in each injection well from the deepest reachable point, without cleanup, in the Mt. Simon (injection zone) to, at a minimum, the Maquoketa Shale (the lowest alternative confining zone). These logs will be run before CO_2 injection to establish a good pre-CO_2 baseline to compare the post CO_2 logging runs. Logs will be run under static conditions with the well shut in and under pressure or killed by various means, presumably with tubing in the hole although valid data can and will be acquired should tubing be pulled for unforeseen reasons. Post CO_2 evaluation will also include a temperature log to further detect fluid movement which will be run over the same intervals and at the same conditions as the sigma logs.

Pre-injection baseline tests will be run and then, following the start of operations, repeated at five year intervals, or more frequently if indicated by other site observations.

Note that data from the St. Peter monitoring well will also provide information useful for demonstrating vertical CO_2 containment via direct measurement.

1.6.1 Direct Pressure Monitoring

One in zone monitoring well will be installed for the project. Construction details for the in-zone wells are included in the attachment to this plan. The proposed well will be located just outside of the projected AOR, in the geological up-dip direction (i.e. to the northwest) (Figure 3). Constant pressure measurements will be made in the injection zone and the data reported and recorded via the project SCADA system. RST logs will be run on each in-zone monitoring well through the same interval and at the same time as the injection well surveys.

1.6.1.1 Quality Assurance and Surveillance Measures

The well gauge will be calibrated prior to installation and then calibrated subsequently according to manufacturers specifications. The data will be evaluated monthly and examined for trends, sudden changes in pressure, or other statistical anomalies in the data. The data and analyses will be included in permit-required operating reports.

1.6.1.2 Plans for Guaranteeing Access to all Monitoring Locations

The location for the in-zone monitoring wells have not been determined at this time, therefore no land or access rights associated with the well have been acquired. Once TEC #1 is installed and the revised AOR is developed, the location of the in zone wells will be identified and TEC will acquire site access.

1.6.2 Indirect Carbon Dioxide Plume and Pressure Front Tracking

A base line two dimensional (2D) seismic survey has been completed at the TEC site and provided the pre-injection parameters of the geologic formations. Once TEC #1 is completed, a geomechanical model will be completed, based on the results of core analyses and other subsurface data. Fluid substitution modeling will also be completed to evaluate the effectiveness of using three dimensional (3D) methods for indirect tracking of the CO_2 front. If this will be an effective method, a 3D baseline survey will be completed prior to injection. Over time, on a periodic basis, additional supplemental periodic seismic surveys may be completed to monitor the migration and lateral/vertical movement of the injected CO_2 plume (Figure 7). The timing and design of the seismic surveys will be performed as necessary or required to meet potential permit and regulatory requirements.

Seismic surveying is proposed as the method to choice for monitoring the extent of the CO_2 in the subsurface. The principle underlying the technique is to generate a seismic signal and then measure velocities of the signal as the waves travel down through the earth geologic formations, and back to sensors coupled on the ground surface. As CO_2 is injected and displaces and/or compresses the native formation brine, expectations are that there would be a change in the formation velocity and density that will affect the acoustic signal travelling through that subsurface geologic zone. Using advance seismic acquisition recording and processing techniques, repeat 3D surveys can be completed and changes in the signal can be identified over time.

Optimization strategies will be considered during the design of each event. Consideration will be given to timing of the survey (e.g. after crop harvest) and to source and receiver line spacing. Either of these may be reduced based on site characteristics or advances in technology. The size of the survey area may also be revised upward or downward to address additional knowledge on the geology or the injected CO_2 plume. In particular, the area may be reduced where the CO_2 is present at an interim position and has not reached its maximum lateral extent as predicted by reservoir modeling.

TEC has developed an excellent relationship with the local community and will obtain permits from public and private landholders, as necessary, to complete the geophysical surveys.

1.7 Other Sampling and Measurements

Other samples will be collected and downhole measurements will be made during installation of each well as described in Section 4 of the Technical Report. The injection and in-zone wells will include samples of cuttings and a mudlog through the primary confining zone and reservoir. Cuttings will also be retained from the St. Peter formation during drilling of injection and deep monitoring wells. Full core and side wall cores will be collected during drilling TEC #1 and will be submitted for laboratory analyses to measure hydrogeologic properties (e.g. porosity, permeability) and geomechanical properties. These data will be used to calibrate the wireline log interpretations and will be used to support the model. Rock samples will be collected in both the Eau Claire formation (primary confining zone) and in the Mt. Simon formation, the target reservoir. Basic wireline logging tools will be run through the intermediate and deep sections of the well and would include gamma logs and resistivity logs. The confining zone and target zone will also include more advanced tools such as formation imaging and magnetic resonance.

*Mark of Schlumberger

References:

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Tables

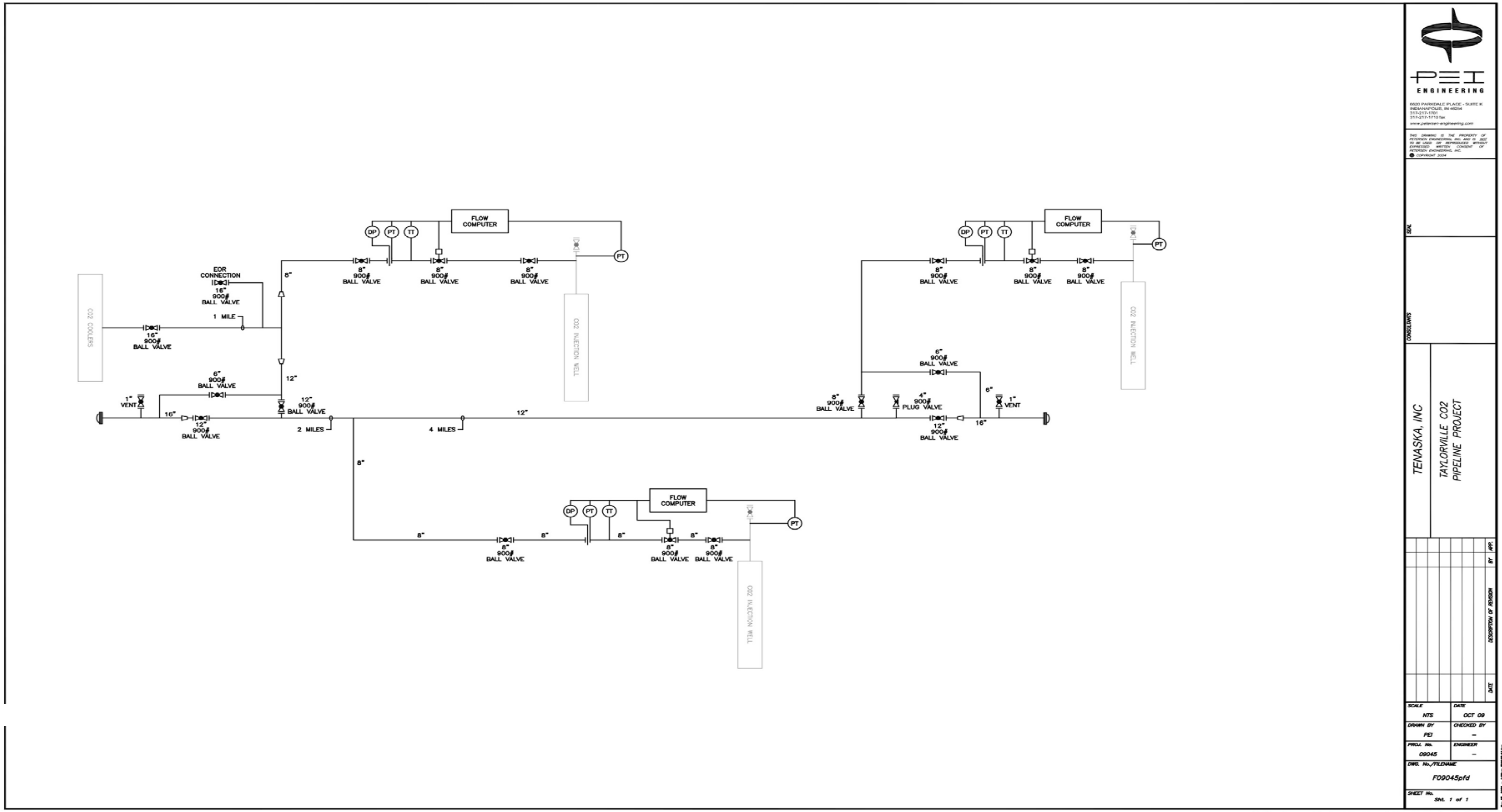
Figures

Monitoring Point	During Injection	Post Injection Site Care (See Post Injection Site Care and Site Closure Plan for details)		
		Years 1 to 5	Years 6 to 10	Thereafter until closure
CO_2 Injectate	Quarterly sampling; annual reporting	None	None	None
Shallow (USDW) Monitoring Wells	Quarterly (annual reporting)*	Quarterly sampling (annual reporting)*	Annual sampling and reporting	Annual sampling and reporting
St. Peter Well	Continuous pressure; annual fluid sampling for years one through 5 then every five years thereafter. Report every five years*	Annual fluid sampling; reporting at year 5	Fluid sampling and reporting year 10	Fluid sampling and reporting every 10 years
In-Zone Monitoring Well	Continuous pressure; report every five years*	Continuous until pressure declines to within 10% of AOR pressure boundary differential. Report at year 5	Continuous until pressure declines to within 10% of AOR pressure boundary differential. Report at year 10	Continuous until pressure declines to within 10% of AOR pressure boundary differential. Report every 10 years
Injection Well	Continuous pressure, temperature, flow. Annual MIT Monthly reporting	Continuous pressure. Annual MIT Report at year 5.	Continuous pressure. MIT at year 10 Report at year 10.	Continuous pressure. MIT every 10 years Report every 10 years.
Pipeline	Continuous temperature and flow. Reporting every five years*	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection
Corrosion Coupons	Coupon sampling and reporting every five years	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection
Injection Well Annulus	Continuous pressure. Monthly reporting	None – annulus will be shut in.	None – annulus will be shut in.	None – annulus will be shut in.
Indirect Monitoring	Survey and report every five years	Survey and report at year 5	Survey and report at year 10	Survey and report every 10 years until closure

* If statistically significant changes or anomalous data are noted before a permit-scheduled reporting interval, TEC will notify US EPA within 30 days of the receiving interpretation or analytical results.

Table 1 Monitoring activity and reporting frequency.

December 1, 2009
Sandia Project No. 1280-ST-09



Christian County Generation, L.L.C.
IEPA Class I. Non-Hazardous Area Permit Application

Schlumberger Carbon Services & Sandia Technologies, LLC

Figure 4-6 TEC Site Process and Instrumentation Diagram of the Proposed CO_2 Pipeline and Injection Well System

Figure 1 TEC Site Process and Instrumentation Diagram of the Proposed CO2 Pipeline and Injection Well System

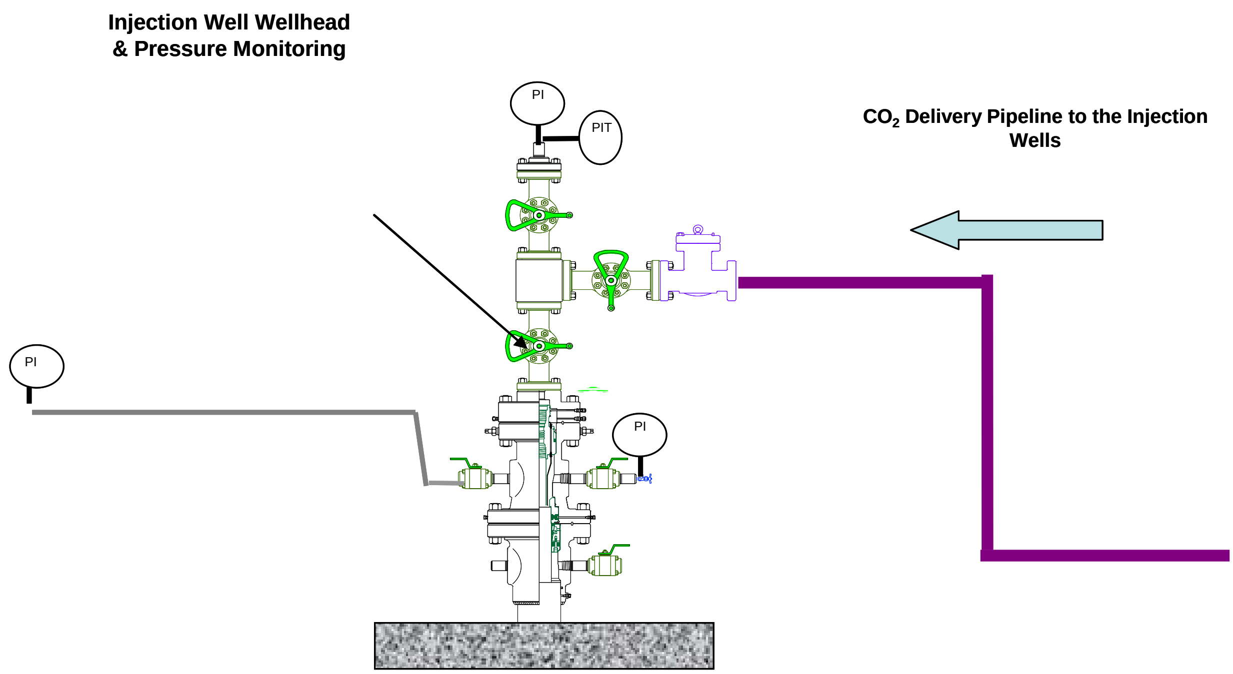


Figure 2 Wellhead and Annulus Pressure Monitoring System

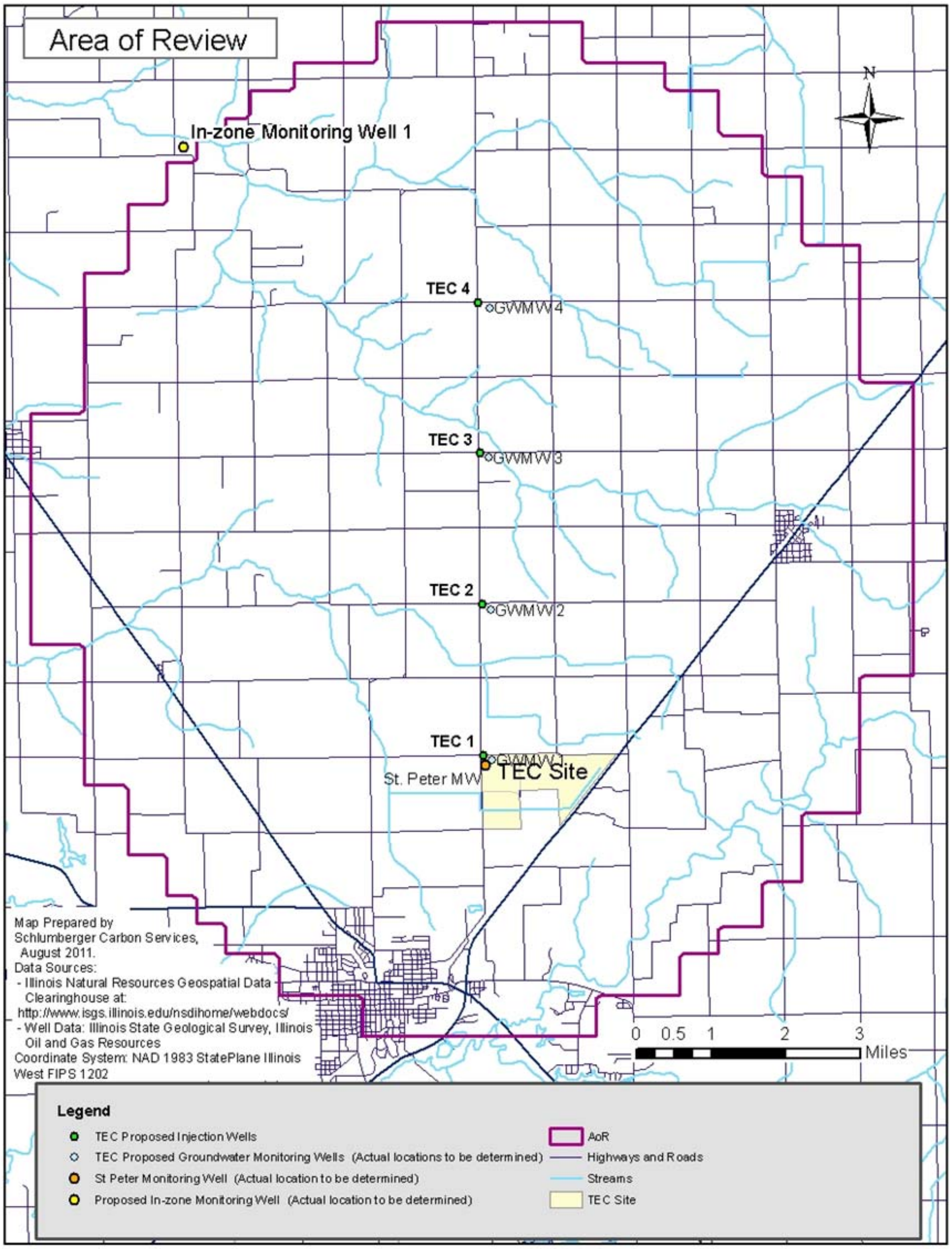
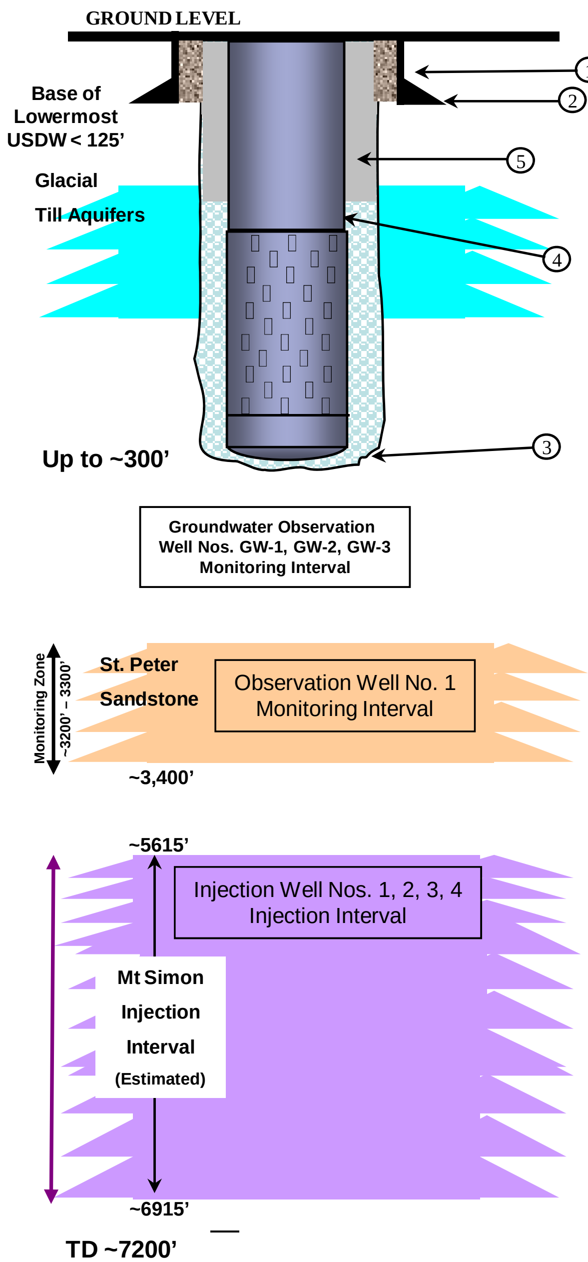


Figure 3 Monitoring well locations

Christian County Generation, L.L.C. (CCG)
#1-GW, #2-GW, #3-GW Shallow Groundwater Observation Wells
[Taylorville Energy Center]
Christian Co., IL
Proposed Well Design Schematic
Status: Proposed

Proposed Location:
Sec. 12 T 13 N R 2 W

Elev. 610 '
KB' = ?



<u>Well Total Depth < 300'</u>

1. Drill 9-7/8-inch borehole to 60 feet
2. Set 6-inch Schedule 80 PVC pipe to 60 feet
3. Drill 5-1/2-inch borehole up to ~300 feet
4. Set 4-inch Schedule 80 PVC pipe (blank) and screen to < 300 feet
   Run GR-Neutron log, or correlate with area water well logs, drillers logs.
   Centralizers to be included on PVC pipe.
5. Seal borehole with grout/cement, to surface to isolate interval.

<u>Final Well Completion (to be determined)</u>:

Well to be completed with a minimum of 10-foot slotted screen and gravel packed

Gravel to extend 2 to 5 feet above the screen

10-foot Bentonite seal placed at top of gravel pack

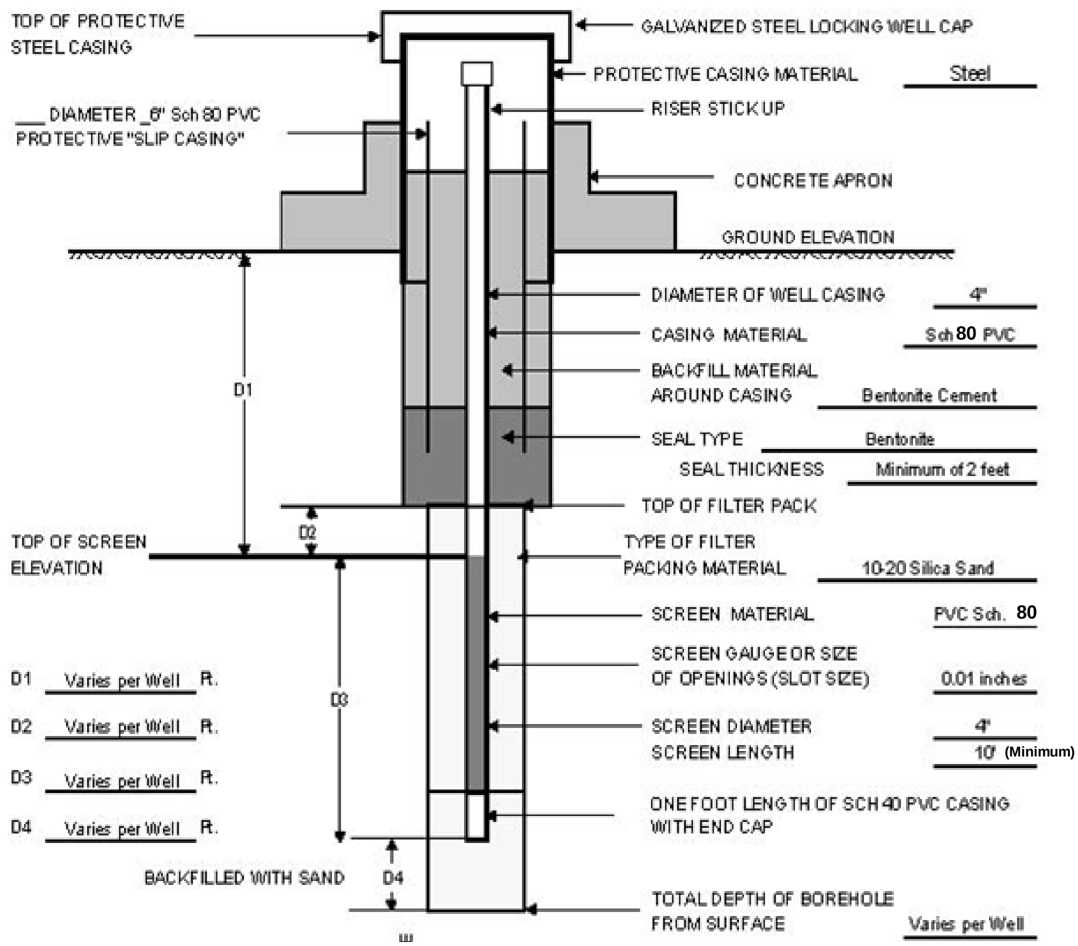
Remaining annulus cemented to surface (casing centralized)

Test shallow glacial till aquifer fluids, using downhole pump.

Shallow lowermost USDW area, glacial tills aquifers fluid sampling area, (protocol of purging 2-3 borehole volumes for fluid sampling events).

Figure 4a TEC #1-GW, #2-GW, #3-GW Shallow Groundwater Observation Wells Proposed Design Schematic

Christian County Generation, L.L.C. (CCG)
#1-GW, #2-GW, #3-GW Shallow Groundwater Observation Wells
[Taylorville Energy Center]
Christian Co., IL
Proposed Surface and Completion Well Design Schematic
Status: Proposed



Note: Individual well locations, proposed monitoring interval and depths to be provided following drilling of TEC 1 injection well and final land acquisition.

Figure 4b TEC #1-GW, #2-GW, #3-GW Shallow Groundwater Observation Wells Proposed Surface and Completion Design Schematic

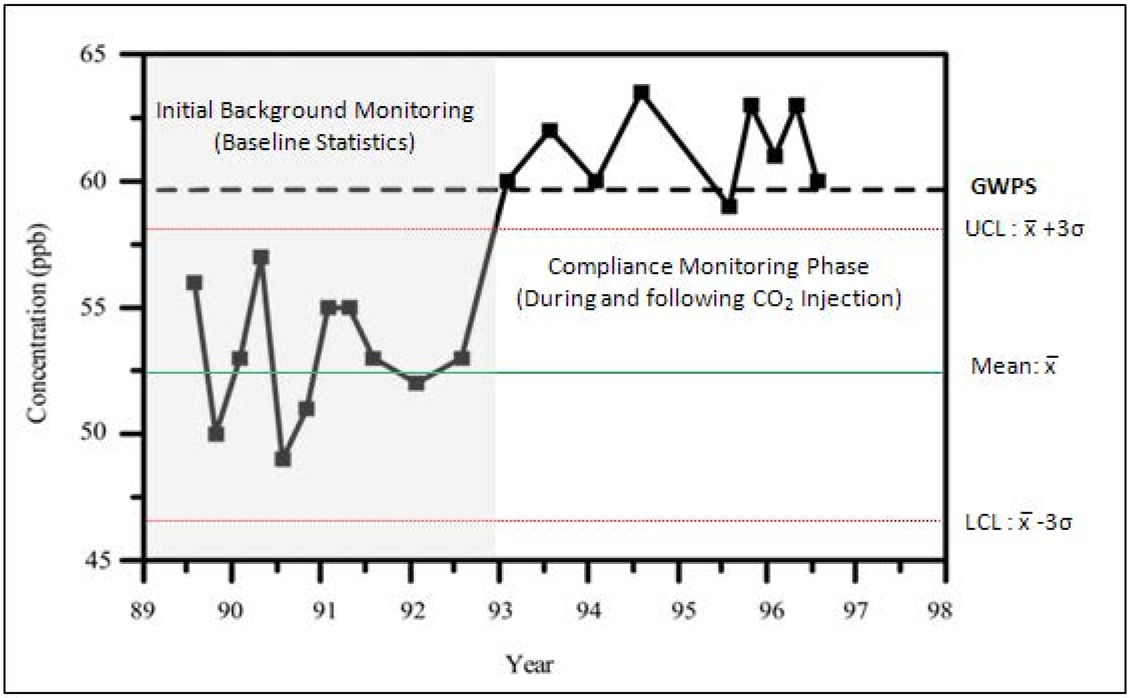


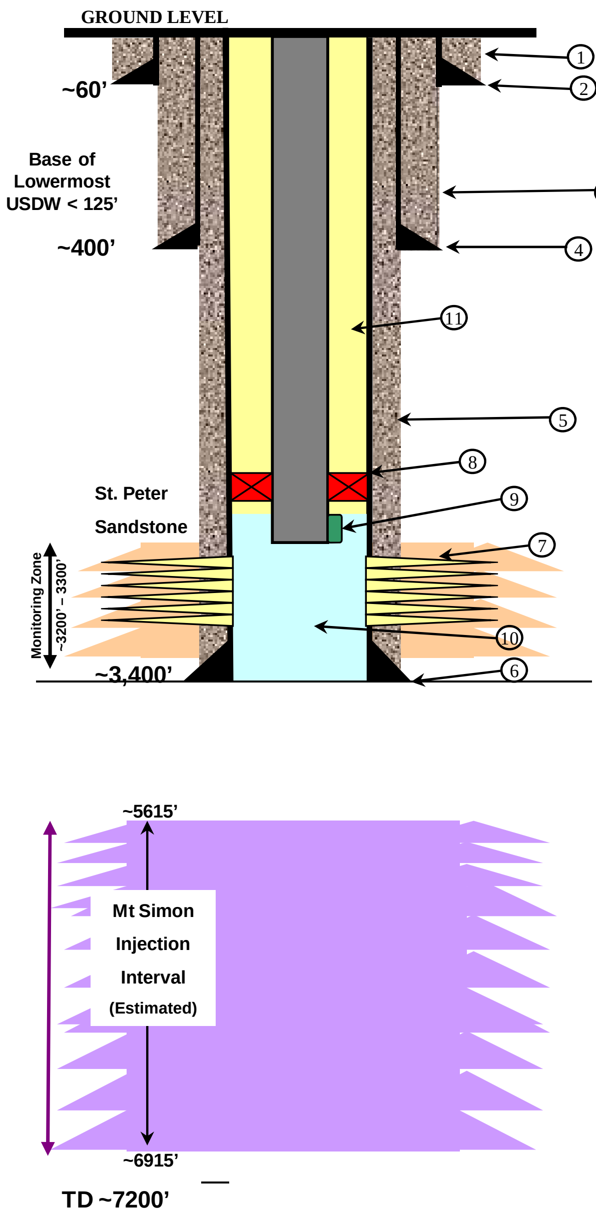
Figure 5 Example Run chart with ground water protection standard limit, (modified, US EPA, 2009).

December 9, 2009

Christian County Generation, L.L.C. (CCG)
#1-St. Peter Observation Well
[Taylorville Energy Center]
Christian Co., IL
Proposed Well Design Schematic
Status: Proposed

Proposed Location:
Sec. 12 T 13 N R 2 W

Elev. 610 '
KB' = ?



Well Total Depth 3,400'

1. Optional drill 20-inch borehole to 60 feet
2. Set 16-inch conductor casing (optional) to 60 feet, circulate cement to surface
3. Drill 12-1/4-inch borehole to ~400 feet
4. Set 8-5/8-inch Surface casing to TD, circulate cement to surface
5. Drill 7-7/8-inch borehole to ~3,400 feet

Run openhole logs, evaluate St. Peter interval.

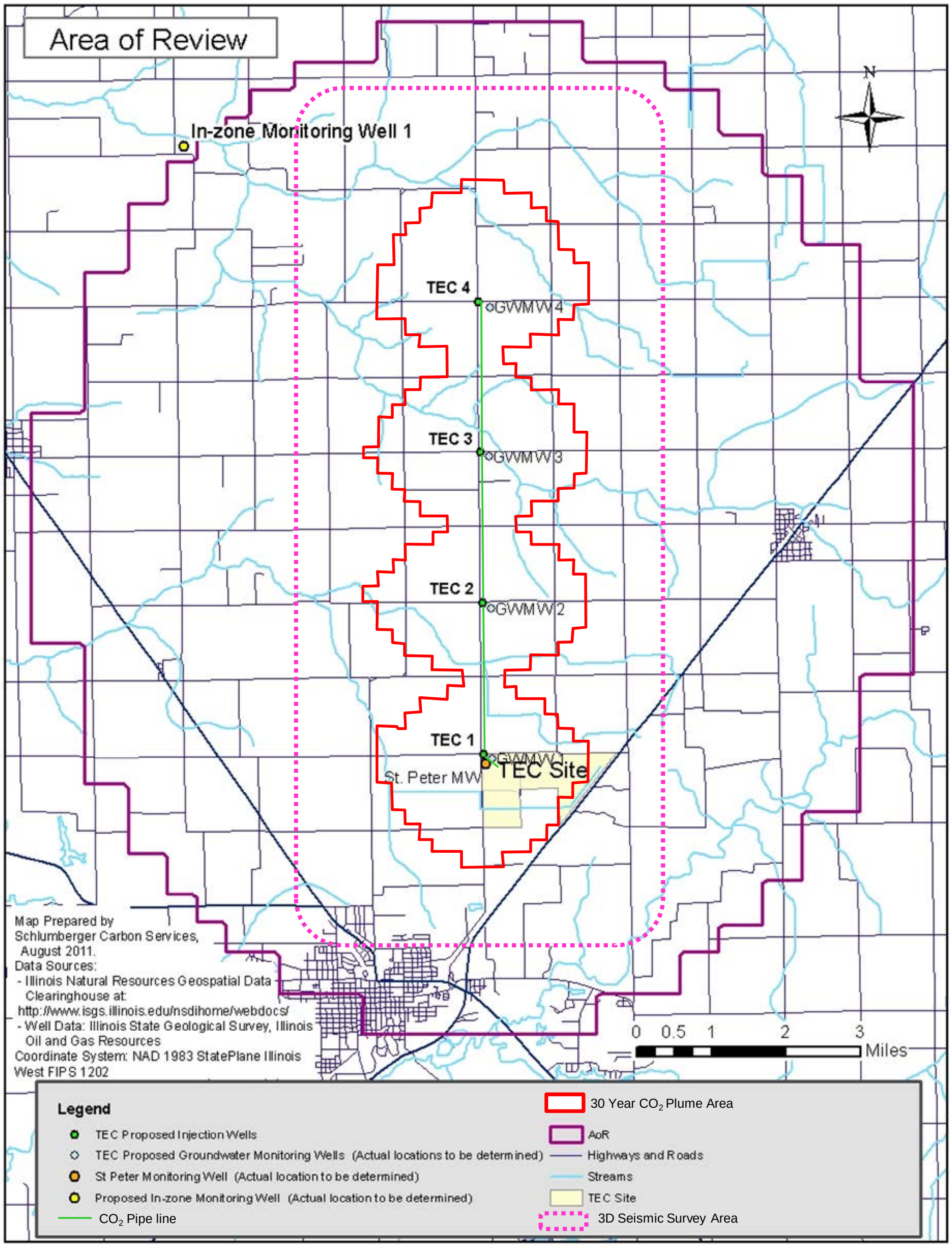
6. Set 5-1/2-inch production casing to TD, cement to surface. Run Cement Bond Log to demonstrate Isolation and borehole Integrity
7. Perforate St. Peter Sandstone (per well log) est. 3200-3300 feet
8. Set packer and 2-3/8-inch tubing to approximately 100 feet above top of perforations
9. Set downhole pressure-temperature instrumentation on tubing end
10. St. Peter Sandstone, fluid sampling area, (protocol of purging 2-3 tubing volumes for fluid sampling events).
11. Fill annulus with inhibited freshwater or brine.

Final Well Completion:

Cased intervals to include centralizers; with the number and location based on hole deviation surveys.
Set instrumentation consisting of downhole pressure-temperature sensors.
Packer, Tubing, annulus system
Test St. Peter Sandstone interval fluids and pressure.

Figure 6 TEC #1-St. Peter Observation Well Proposed Design Schematic

TEC #1-St. Peter Sandstone Observation Well *Sandia Technologies, LLC*



Area map showing location of possible 3D seismic survey

Attachment 1 In-zone monitoring well design and installation plan

A1.0 Well Design

A1.1 Well Casing Specifications

Prior to initiating drilling activities, 20-inch conductor pipe may be set to 45-60 feet KB using a rat hole service or small air rig and cemented in place. The conductor pipe would be installed if it is determined to be needed for hole stability. A 17.5-inch or larger surface hole will be drilled to a depth of at least 100 feet below the lowermost USDW (estimated at 125 feet KB). For permitting purposes, a maximum depth of approximately 400 feet KB is assumed for the surface casing. At that point, 13 3/8-inch or 16-inch surface casing will be run and cement circulated to surface. The 12-1/2-inch intermediate hole will be drilled into the Eau Claire formation to approximately 5,400 feet KB and then 9-5/8-inch intermediate casing will be run to current total depth and cemented to surface. For the production (monitoring) portion of the well, an 8-3/4-inch borehole will be drilled through the Mount Simon Sandstone injection formation to a total depth of approximately 7,200 feet. A production string of 5-1/2-inch casing will be set through the entire Mount Simon sandstone interval. A 2-7/8-inch tubing string will be set at approximately 5600 ft near the top of the Mount Simon using a retrievable packer.

The casing design summary is shown below:

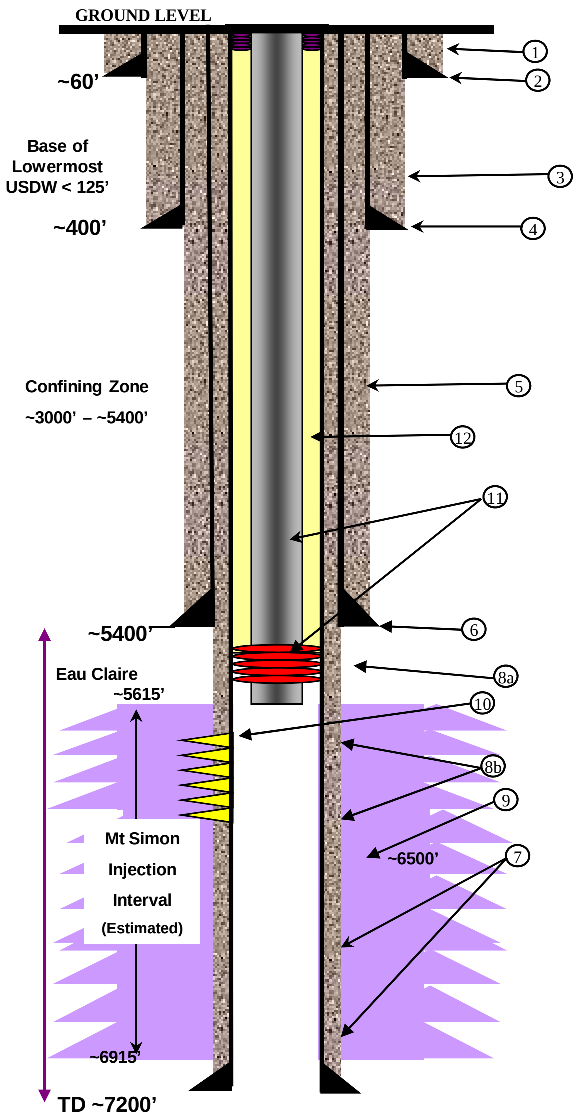
Table A1-1

Monitoring Well Casing Design Summary

Borehole Size	Casing Size (OD)	Estimated Setting Depth	Casing Seat Justification
Inches	Inches	KB Ft	
26	20	60 +/-	Structural Support. Prevent surface washout.
17-1/2 or larger	13-3/8 or 16	400 +/-	Seal off potential troublesome glacial till and provide a good casing seat for kick tolerance. Engineered oilfield practice.
12-1/4	9-5/8	5,400 +/-	Seal of the St. Peter sandstone and Eau Claire shales protects long string and provides a seal for the upper confining units and sandstones.
8-3/4	5-1/2	7,200 +/-	Total depth below Mount Simon.

Christian County Generation, L.L.C. (CCG)
In Zone Monitoring Well
[Taylorville Energy Center]
Christian Co., IL
Proposed Well Design Schematic
Status: Proposed

Elev. ~610 '
KB' = ?



Well Total Depth 7200'

1. Optional: Drill 26-inch borehole to ~60 feet
2. Set 20-inch conductor casing (optional) to TD, circulate cement to surface
3. Drill 17.5-inch borehole to ~ 400 feet
4. Set 13-3/8-inch or 16-inch Surface casing (68 lb/ft J-55 or 84 lb/ft J-55) to TD, circulate cement to surface

Perform Leak-off test or Formation Integrity Test at casing shoe area.

5. Drill 12-1/4-inch borehole to ~5,400 feet
6. Set 9-5/8-inch intermediate protection casing (using 40 lb/ft N-80) to section TD, cement to surface.

Run Cement Bond Log to demonstrate Isolation and borehole Integrity

Perform Leak-off test or Formation Integrity Test at casing shoe area.

7. Drill 8 3/4-inch hole from TD to ~7200 feet.
8. Set 5-1/2-inch production casing (17-lb/ft J-55) from surface to design depth; cement to surface.
9. Well completion interval based on evaluation of field data
10. Set Injection packer, 2-7/8-inch tubing (6.5 lb/ft J-55) and hanger @ ~ 5,600 feet across lower Eau Claire section.
11. Fluid-filled Annulus.

Final Well Completion:

Cased intervals to include centralizers; with the number and location based on hole deviation surveys.

Perforate based on completion interval data

Set Packer and Tubing; Demonstrate Mechanical Integrity Testing.

Test Mount Simon Sandstone Injection Interval.

Figure A1 In-zone Monitoring Well Proposed Design Schematic

The proposed casing specifications for the monitoring well are shown in the table below:

Table A1-2

Minimum Monitoring Well Casing Specifications

Tubular	Approx. Depth	Size OD/ID	Weight	Grade	Conn. Type and OD	Collapse/Burst	Body YS	Thermal Conductivity
	KB Ft	Inches	Lb/ft		OD inches	Psi	Lbs x 1000	BTU/Ft.hr.°f
Conductor	60 +/-	20/19.124	94	H-40	STC (21)	520/2,110	1077	29.02
Surface	400+/-	13-3/8/12.51 Or 16/15.010	61 Or 84	J-55 Or J-55	STC or LTC (14.375) Or STC (17.00)	1,540 / 3,090 Or 1,420 / 2980	962 Or 1326	29.02 Or 29.02
Intermediate	5,400 +/-	9-35/8/8.835	40	N-80	LTC or STC (10.625)	3,090 / 5,750	916	29.02
Monitoring	7,200 +/-	5-1/2/4.892	17	J-55	LTC or STC (6.050)	4910 / 5,320	273	29.02
Tubing	5600 +/-	2-7/8/2.441	6.5	J-55	U	7,260/7,680	99.7	29.02

Note: The casing weights and grades as outlined are the minimum specification, higher grades and heavier weights may be used if needed.

A1.2 Well Casing Design Considerations

The following considerations were derived from a review and knowledge base of offset wells drilled in the central Illinois Basin, and Illinois State Geological Survey geological interpretations for incorporation and refinement of the well design and casing program:

- Potentially serious loss circulation problems in the deeper formations.
- An apparently normal pressure regime for all wells reviewed and through peer reviews conducted with personnel that have drilled wells in the Illinois Basin (0.433 – 0.445 psi/ft) and from publicly released information from the nearby ADM well.
- A review of primarily all oil wells and gas storage wells drilled in the northern portion of the basin.
- The Mount Simon Sandstone is a thick and heterogeneous formation expected to range from 1,100 – 1,300 feet of gross thickness. (Note: this thickness will be determined upon review of the data and logs and cores from the TEC Injection Well No. 1).
- Several wells penetrating the shales above the Eau Claire have reported some borehole instability across these shale sections. To counter this, the well will be drilled with low solids, non-dispersed water base drilling fluid.

A1.3 Well Casing Design Standards

Standards utilized for casing and drilling are as follows:

- All surface, intermediate and production casing will be pressure tested prior to drilling out the shoe track or perforating. Subsequently, such tests will be repeated whenever the integrity of the casing is in doubt (long rotating hours, high dogleg severity, etc.). A pressure test will be conducted on the production casing/liner prior to perforating.
- Well control will be maintained while running casing through maintenance of borehole fluid column, barriers, and surface well control systems.
- The casing installed in any well shall be designed to withstand burst, collapse, tension, bending, buckling or other stress that are known to exist or that may reasonably be expected to exist.

- The performance properties of any casing shall be considered to be those listed for that casing in the American Petroleum Institute's (API) Bulletin on Performance Properties of Casing, Tubing, and Drill Pipe, API BUL 5C2, nineteenth edition, October 1984.
- Centralizers will be used as needed.

A1.4 Minimum Design Factors

Table A1-3

Minimum Design Factors

Design Loads	Surface/Intermediate Casing, Drilling Liners	Production Casing Liners
Collapse	1.0	1.1
Burst:		
Normal Service	1.1	1.1
Critical Service	1.25	1.25
Tension:		
Pipe Body	1.3	1.3
Connection	1.5	1.5
Compression	1.3	1.3
Triaxial	1.25	1.25

- The casing installed in any well shall be designed to withstand collapse loading based on the following assumptions:
  1. The hydrostatic head of the drilling fluid in which the casing is run acts on the exterior of the casing at any given depth.
  2. Subject to the casing is 1/3 evacuated.
  3. The production casing is completely evacuated.
  4. The effect of axial stresses on collapse resistance shall be taken into account.
  5. The effect of temperature deration and casing wear shall be taken into account.
- Any casing/liner that creates an annular space with the production tubing shall be treated as a production casing/liner.

- The casing installed in any well shall be designed to withstand tensile loading based on the following assumptions:
  1. The weight of casing is its weight in air.
  2. The tensile strength of the casing is the yield strength of the casing wall or of the joint, whichever is the lesser.

A1.5 Casing Design Assumptions

The following assumptions were made during the design process for the monitoring well at Taylorville:

- A 5% casing wear due to Bottomhole Assembly (BHA) rotation is assumed on all casing design segments with consecutive hole sections.
- Wall tolerance of 87.5 % is assumed as per API standards.
- Temperature deration is taken into account on the design of the 16-inch, 9-5/8-inch, and 5-1/2-inch casing strings.
- The 9-5/8-inch casing is being proposed and engineered to be required to comply with a casing design standard (IPM-WELL-S029) to pass a 1/3 evacuation loading on collapse. (This standard is well above the standard as utilized in normal oil and gas applications, and best practices and engineering disciplines.)
- The 5-1/2-inch casing string will have to pass a calculated evacuation loading to approximately 3500 feet. (The 5-1/2-inch long string casing will be cemented into the 9-5/8-inch casing for extra protection and to preserve the integrity of the long range goals of injecting super-critical liquid CO_2)
- The casing is designed to offer the most cost effective, engineering-wise acceptable option to the project, designed to preserve the integrity of the operation for the life of the commercial TEC project. In the event that the casing recommended is not available, final casing selection would be based on what other technical options are currently available and what might be in stock in Houston, TX tubular supplier's inventory. The minimum criteria for an alternate design would be to exceed standard design criteria.

A1.6 Casing Design Models

Table A1-4
Casing Design Models

16-inch Surface Casing

Load Case	Pressure	Profile	Temp	Wear	Minimum	Design	Factor	
	Internal	**External**	**Profile***	**%**	**Burst**	**Collapse**	**Tension**	**Triaxial**
As Run	9.6 ppg mud	9.6 ppg Mud	Satic	5			22.38	40.87
Green Cement Press Test	9.6 ppg + 1,410 psi	Cement	Static	5	4.67		7.70	5.19
Installed Load	9.6 ppg mud	Cement	Static	5		9.46	38.67	22.40
1/3 Evacuation – 5400 ft	1/3 Evac	9.6 ppg mud	Static	5		6.23	36.49	15.01
Pressure Test – 400 ft	9.6 ppg + 2374 psi	PP	Static	5	1.25		3.81	1.36
50 bbl Gas Kick – 5400 ft	50bbl gas kick	PP	50bbl gas kick	5	4.51		15.84 (compression)	3.96
1/3 Replacement - 5400 ft - Circulating	1/3 Replacement	PP	Circulating	5	3.15		14.65	3.32
1/3 Replacement - 5400 ft – Static	1/3 Replacement	PP	Static	5	3.15		7.33	3.47

9-5/8-inch Intermediate Casing

Load Case	Pressure	Profile	Temp	Wear	Minimum	Design	Factor	
	Internal	**External**	**Profile***	**%**	**Burst**	**Collapse**	**Tension**	**Triaxial**
As Run	9.6 ppg mud	9.6 ppg mud	Static	5			3.98	4.40
Green Cement Press Test	9.6 ppg + 1410 psi	Cement	Static	5	4.08		3.87	3.79
Installed Load	9.6 ppg	Cement	Static	5		2.72	5.30	5.86
1/3 Evacuation - 7150 ft	1/3 Evac	9.6 ppg mud	Static	5		2.31	4.99	4.18
Pressure Test - 5400 ft	9.6 ppg + 4460 psi	PP	Static	5	1.23		2.92	1.33
50 bbl Gas Kick - 7150 ft	50 bbl gas kick	PP	50 bbl gas kick	5	3.96		6.29	4.31
1/3 Replacement - 7150 ft - Circulating	1/3 Replacement	PP	Circulating	5	4.19		5.11	4.34
1/3 Replacement - 7150 ft - Static	1/3 Replacement	PP	Static	5	4.20		3.99	3.95

5-1/2-inch Intermediate Casing

Load Case	Pressure	Profile	Temp	Wear	Minimum	Design	Factor	
	Internal	External	Profile*	%	Burst	Collapse	Tension	Triaxial
As Run	10.5 ppg mud	10.5 ppg mud	Static	5			2.42	2.38
Green Cement Press Test	10.5 ppg + 1340 psi	Cement	Static	5	3.97		2.46	2.47
Installed Load	10.5 ppg mud	Cement	Static	5		3.82	2.42	2.38
Full Evacuation - Static	Complete Evacuation	10.5 ppg mud	Static	5		1.13	2.26	1.34
Pressure Test - 7150 ft	10.5 ppg + 3863 psi	PP	Static	5	1.23		1.83	1.34

2-7/8-inch Tubing

Load Case	Pressure	Profile	Temp	Wear	Minimum	Design	Factor	
	Internal	External	Profile*	%	Burst	Collapse	Tension	Triaxial
As Run	10 ppg mud	10 ppg mud	Static	5			6.34	5.67
Installed Load	10 ppg mud	10 ppg mud	Static	5			6.34	5.67
Full Evacuation - Static	Complete Evacuation	10 ppg mud	Static	5		4.50	6.96	4.80
Pressure Test - 5610 ft	10.5 ppg + 1000 psi	PP	Static	5	14.34		5.82	5.67

A1-6 Casing Design Envelope

Casing	Design Pressure Test (psi)	Design KT in next hole section
16-inch	2376	25 bbls with 0.5 ppg kick intensity
9-5/8-inch	4460	25 bbls with 0.5 ppg kick intensity
5-1/2-inch	3863	25 bbls with 0.5 ppg kick intensity

A1.7 Well Construction Schematic

A well design schematic of the proposed monitoring well has been prepared and depicts the drilled borehole and casing sizes, with depths, as well as the location of the Mount Simon Sandstone injection interval. (See Figure A1 for monitoring well design)

A2.0 Casing Program for Site Injection Wells

A 26-inch (or larger) borehole with a section of 20-inch conductor casing may be set to a depth of +/- 45-60 feet in the shallow well area to offer integrity and stability to the surface borehole. A 17.5-inch or 18.5-inch surface borehole will be drilled to a depth of approximately 400 feet KB. At that point, 13-3/8-inch or 16-inch diameter surface casing will be set and cemented to surface to isolate all local USDWs and provide kick tolerance. A 12-1/4-inch borehole will be drilled from 400 feet to a total depth of approximately 5,400 feet KB and 9-5/8-inch protection casing will be set and cemented from this section of total depth to surface. The casing shoe will be set in the Eau Claire confining horizon which is expected to be a low permeability seal overlying the injection interval. The Mount Simon Sandstone monitoring interval will then be drilled using a 8-3/4-inch borehole to a depth of approximately 7,200 feet and a 5-1/2-inch casing will be set and cemented from total depth to the surface. Centralizers will be used as needed in the intermediate and deep sections of the monitoring wells, based on the hole directional and deviation surveys.

A2.1 Perforation and Completion

The monitoring well will be perforated in the Mt Simon and a pressure gauge will be used to monitor pressure continuously during the injection and PISC phases of the project. Depending on the final completion the gauge may be run through tubing.

A3.0 Monitoring Well Drilling Program

A general program for drilling monitoring well will be performed utilizing best engineering practices and knowledge from drilling Mount Simon Sandstone, while using Class VI injection well standards. If there are design changes based on site conditions, TEC will prepare a revised well prognosis and well design and submit to Region 5 for review and concurrence.

A4.0 Cementing Program

The following are cementing specifications for the monitoring well. Actual volumes and quantities will depend on site specific borehole conditions and final casing depth settings. Well logs, including CemCade or equivalent will be completed for each borehole section to guide the cementing program.

Table A4-1

Proposed Cementing Program for Monitoring Wells

Name	Depth Interval (feet)	Type/ Grade	Additives	Quantity (cubic feet)	Circulated to Surface	Thermal Conduct. BTU (ft.hr.°F)
Surface[1]	0-400	Class A	Accelerator, LCM	~600	Yes	0.73
Intermed.[2]	0-5,400	50:50 LP3:Class A	extender, antifoam, accelerator	~1400 (lead), ~750 (tail)	Yes	0.54
Long[3]	0-base of long string	DCO_2 (acid gas resistant)	Antifoam, dispersant, fluid loss + antisettling(tail)	~1150 (lead), ~860 (tail)	Yes	0.75

1 Surface casing Class A + 2% CaCl2 accelerator + 0.25 lb/sk D130 LCM, Density: 15.6 ppg Yield: 1.20 cf/sk Mix water: 5.23 gal/sk

2 Intermediate casing Int lead slurry: 50:50 LP3:Class A + 6% D020 extender + 0.2% D046 antifoam + 2.5% S001 accelerator, Density: 13.3 ppg Yield: 1.51 cf/sk Mix water: 7.502 gal/sk;
Followed by tail slurry of: Class A + 0.2% D046 antifoam + 0.5% D065 dispersant + 0.25% D167 fluid loss additive, Density: 15.6 ppg Yield: 1.19 cf/sk Mix water: 5.234 gal/sk

3 Long string casing Lead slurry: 1 35:65 LP3:Class A + 6% d020 extender + 10% salt BWOW + 0.1% D013 retarder + 0.2% D046 antifoam + 0.2% D065 dispersant + 0.2% D167 fluid loss additive, Density: 12.8 ppg Yield: 1.96 cf/sk Mix water: 10.54 gal/sk; Followed by tail slurry: DC02 Acid-Gas-Resistant Blend + 0.16 gal/sk D080 dispersant + 0.2 gal/sk D168 fluid loss additive + 0.03 gal/sk D175 antifoam + 0.1 % D153 antisettling additive, Density: 15.8 ppg Yield: 1.09 cf/sk Mix water: 3.012 gal/sk

A4.1 Surface Casing Cementing Program

The following cementing program is proposed for installation of the surface casing string:

- 16-inch casing in a 18-1/2-inch borehole at +/- 400 feet KB
- Pump cement to surface
- Estimated borehole volume was calculated using 50 % excess over bit size (gauge hole)
- Actual calculated volume from open-hole caliper log plus 20 % excess

Cement Slurry	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume Sacks
Cement Slurry	15.6	1.20	5.23	~500

<u>Spacer</u>:

20 bbl of fresh water

<u>Cement Slurry:</u>

Class A Cement + 2% $CaCl_2$ accelerator + 0.25 lb/sack D130 LCM

4.5.2 Intermediate Casing Cementing Program

The following cementing program is proposed for installation of the intermediate casing string:

- 9-5/8-inch casing in 12-1/4-inch borehole at +/- 5,400 feet KB
- Pump cement to surface
- Estimated borehole volume was calculated using 50 % excess over bit size (gauge hole)
- Actual calculated volume from caliper log plus 20 % excess on the second stage
- Intermediate casing Int lead slurry: Density: 13.3 ppg Yield: 1.51 cf/sk Mix water: 7.502 gal/sk;

Cement Slurry	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume Sacks
Lead Cement	13.3	1.51	7.502	1120
Tail Cement	15.6	1.19	5.234	630

Cement Slurry	Specifications
Spacer:	20 bbl of mud flush spacer 20 bbl fresh water spacer
Lead Cement:	Class A Cement + 6% D020 50:50 LP3:Class A + 6% D020 extender + 0.2% D046 antifoam + 2.5% S001 accelerator,
Tail Cement:	Class A Cement + 0.2% DO46 antifoam Followed by tail slurry of: Class A + 0.2% D046 antifoam + 0.5% D065 dispersant + 0.25% D167 fluid loss additive

A4.2 Long String (Production) Casing Cementing Program

The following cementing program is proposed for installation of the long string casing:

- 5-1/2-inch casing in 8-3/4-inch borehole at +/- 7,200 feet RKB
- Pump cement to surface
- Estimated borehole volume was calculated using 20 % excess over bit size (gauge hole)
- Actual calculated volume from caliper log plus 20 % excess on the second stage
- DCO_2 Acid-Gas-Resistant Blend Cement
- Intermediate casing Int lead slurry: Density: 13.3 ppg   Yield: 1.51 cf/sk   Mix water: 7.502 gal/sk;

The monitoring casing cement job will likely be a single stage circulation technique. A casing float shoe will be placed on the bottom of the long string casing and a float collar placed one joint of casing above the bottom. A bottom wiper plug will be used to wipe the mud film from the casing ahead of the cement job. The bottom of the injection zone monitor casing will be set a few feet off the bottom of the hole. The actual cement pumping and displacement rates will be determined using a cement placement simulator and will depend upon well specific parameters such as mud properties and hole size learned during the actual drilling process from the wireline surveys, including a caliper log. The surveys and cement reports will be provided in the well completion report. A custom spacer will be designed based on the final hole conditions and will be pumped ahead of the cement system to assist in mud removal.

Although single stage cement jobs are planned for all casing strings, information learned during the drilling process (e.g. lost drilling returns) and testing of the open-hole (e.g. significant features identified via well logs) may lead to a decision to use a two stage cementing technique on any or all of the strings. Should a two stage cement system be required for the long string, the lower cement stage will cover the Mount Simon and Eau Claire and come up to a few hundred feet above the Eau Claire. A stage cementing tool will be run on the long string casing allowing the second stage or upper section to be cemented after the lower cement stage has reached 500 psi compressive strength. The designed lead system will cover the upper hole section and a small amount of the CO_2 resistant cement tailed in and placed across the stage cementing collar. The stage cementing collar will be drilled out and casing integrity test performed.

Cement Slurry	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume Sacks
Lead Cement	12.8	1.96	10.54	~585
Tail Cement	15.8	1.09	3.012	~790

Cement Slurry	Specifications
Spacer:	20 bbl of mud flush spacer 20 bbl fresh water spacer
Lead Cement:	Class A Cement + 6% D020 extender 35:65 LP3:Class A + 6% D020 extender + 0.10% salt BWOW+0.1% D013 retarder +0.2% D046 antifoam + 0.2% D065 dispersant + 0.2% D167 fluid loss additive, Density: 12.8 ppg Yield: 1.96 cf/sk Mix water: 10.54 gal/sk;
Tail Cement:	DCO_2 Acid-Gas-Resistant Blend Cement +0.16 gal/sk D080 dispersant + 0.2 gal/sk D168 fluid loss additive + 0.03 gal/sk D175 antifoam + 0.1 % D153 antisettling additive, Density: 15.8 ppg Yield: 1.09 cf/sk Mix water: 3.012 gal/sk

A4.3 CO_2 Resistant Cement

CO_2 resistant cement will cover the entire base of the long string and be placed approximately 500 feet back into the 13-3/8-inch casing. Assuming the intermediate casing will be set 50 feet into the Eau Claire, the CO_2 resistant cement will be about 450 ft above the Eau Claire, thus ensuring protection of the cap rock from the effects of injected CO_2. The CO_2 resistant cement properties are provided below. It is important to note that the properties of the cement slurry will change with mix density and temperature.

A5.0 Drilling Fluids Program

The final drilling fluids program will be provided before move-in and rig-up, and spud of the well.

BHCT (Bottomhole Circulating Temperature)	40 degC [104 degF]
BHST (Bottomhole Static Temperature	50 degC [122 degF]
Density [lbm/gal]	15.8 lbf/gal expected (can be mixed between 12.5 to 16 lbf/gal)
Rheological properties determined with R1B5 after mixing (these will vary with cement mix density and temperature)	
PV (cp) (Plastic viscosity)	208
Ty (lbf/100ft2) (Yield Strength)	9
After conditioning at BHCT (If BHCT varies or the cement density varies the values below will also vary)	
PV (cp)	207
Ty (lbf/100ft2)	15
10 sec Gel Strength (lbf/100ft2)	7
10 minute Gel strength (lbf/100ft2)	32
Then 1 minute stirring gel strength (lbf/100ft2)	14
Stability	OK
API fluid loss at BHCT	54
Thickening time at BHCT	
30Bc	3h 54min
70Bc (unpumpable)	4h 31min
UCA cell compressive strengths	
50 psi	6h 16min
500 psi	8h 04min
24 hour comp. strength psi	2982

Conductor Hole (26-inch hole size)

This interval (if needed), may be pre-drilled with a portable drilling rig or a rathole company to approximately 60 feet (30 – 40 feet below GL). Drilling fluid is not planned for this section unless required by hole conditions. If it is required, a spud mud with a funnel viscosity in the range of 45 sec/1000 cc will be used.

Surface Hole (16-1/2-inch hole size)

Depth (Feet)	Mud Type	Weight (Lb./gal)	Viscosity (Funnel-sec.)	Fluid Loss (cc/30 min)
0-400	Freshwater Gel	8.6 – 9.1	40 - 65	NC

Notes:

1) Lost circulation material (LCM) will be available on location to treat for fluid losses in shallow sands. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones.
2) The fluid density will be maintained to contain the formation reservoir pressures without inducing flow to the wellbore.
3) High-viscosity gel sweeps may be used to assist hole cleaning.

Intermediate Hole (12-1/4-inch hole size)

Depth (Feet)	**Mud Type**	**Weight** (Lb./gal)	**Viscosity** (Funnel-sec.)	**Fluid Loss** (cc/30 min)
400 - 5,400	Freshwater Gel	8.6 - 9.2	40 - 55	NC – 12

Notes:

1) Should lost circulation or fluid seepage occur, materials designed for that problem will be used to remedy the problem on an "as needed" basis.
2) The fluid density will be maintained to contain the formation reservoir pressures without inducing flow to the wellbore.
3) High-viscosity sweeps will be used as needed to assist hole cleaning.
4) The fluids may be treated with zinc oxide or zinc carbonate for potential hydrogen sulfide.

Production Hole Monitoring Interval (8-3/4-inch hole size)

To protect the formations from near wellbore permeability and porosity damage a Drill In Fluid (DIF) may be utilized. The fluid will be fresh water plus 3 – 6 % KCl and a premium grade non-dispersed xanthum gum (viscosifier) and starch (filtrate control) and sized $CaCO_3$ (bridging agent) and a biocide (bacteria control) and possibly a clay stabilizer.

Depth (Feet)	**Mud Type**	**Weight** (Lb./gal)	**Viscosity** (Funnel-sec.)	**Fluid Loss** (cc/30 min)
5,400 – 7,200	3-6 % KCl/ Polymer	8.6 - 9.6	40 - 52	<12

Notes:

1) Should lost circulation or fluid seepage occur, graded calcium carbonate will be used to remedy the problem on an "as needed" basis.
2) The fluid density will be maintained to contain the formation reservoir pressures without inducing flow to the wellbore.
3) High-viscosity sweeps will be used as needed to assist hole cleaning.
4) Treat the drilling fluid with zinc oxide or zinc carbonate for potential hydrogen sulfide.

Injection Well Plugging Plan

1.0 Facility Information

Facility Name: Taylorville Energy Center

Applicant Name: Christian County Generation, L.L.C.
1044 N 115 St., Suite 400
Omaha, NE 68154-4446

Facility Contacts: Ryan Choquette, Project Manager
Ph. 402-938-1641
e-mail rchoquette@tenaska.com

Location: 1630 N 1400 E Road, Taylorville, Christian County, IL 62568

2.0 Planned Tests or Measures to Determine Bottom-hole Reservoir Pressure

At the conclusion of injection, well pressures (surface) will continue to be monitored. Once these well pressures have stabilized, the well will be flushed with brine as described below (Abandonment Post Injection). A logging run will be completed to measure downhole temperature and pressure. High pressure logging gear may be used, depending on site conditions. This information, along with the results of the planned external mechanical integrity tests (below) and an updated plugging plan will be submitted to US EPA at least 30 days prior to abandoning the well.

3.0 Planned External Mechanical Integrity Test(s)

USI* ultrasonic imager and CBT* cement bond tool. USI will provide an internal radius and pipe thickness. This will be compared to the baseline (as built) thickness. CBT combined with USI will help to assess integrity of the cement. Notifications to US EPA will be made as noted above.

4.0 Information on Plugs

4.1 Plug and Abandonment Discussion

A discussion is presented on the potential abandonment planned for during well construction which may be due to unforeseen circumstances encountered during drilling and well completion construction. Note that a decision may be made to plug back as necessary and side track the hole. Additionally, a proposed plan is offered using the standard plugging method for abandonment of the injection well(s) post-injection. In both cases, the Balanced Plug Cement

Plug Placement Method will be used, which represents a widely used and accepted technique and method employed in the petroleum industry to place cement plugs.

4.2 Abandonment During Construction

Three potential well abandonment scenarios exist during the phase of well construction (drilling and completion), while the wellbore remains open or uncased:

- Drilling the Surface Hole (<400 ft MD),
- Drilling the Intermediate Hole (<5,400 ft MD), and
- Drilling the Long-String Hole (<7,200 ft MD).

Assumptions from these three scenarios, indicates that the drill string (drill collars, drill pipe, and drill bit) is the most likely tubular equipment to be present in the borehole. If drilling components are stuck, multiple attempts will be made to recover all of this equipment prior to abandonment. If drill pipe, drill collars and/or drill bit are stuck and not retrieved, they must be abandoned in the wellbore. Standard plugging procedures are required with plugs placed as required by the UIC Permit. The same procedure will be used if any testing tool such as a core barrel or drillstem testing assembly or non-radioactive well log tool is stuck in the wellbore.

If a radioactive source logging tool (density and/neutron porosity) is stuck or lost in the hole, current Nuclear Regulatory Commission (NRC) regulations will be followed. A 300-foot, red cement plug will be placed immediately above the lost logging tool. An angled, kick-plate will be placed above this plug to divert any subsequent drilling that may coincidentally enter this wellbore. Current NRC regulations require that the surface casing remain extended above the ground surface with an informative ground plate welded to the pipe. The plate includes information about the well to identify what is remaining in the hole.

For plug and abandonment during construction, plugs will be proposed and set depending on the specific situation encountered during that event. Abandonment during well construction will likely have a combination of mud and/or cement plugs. The mud weight will be that used at the depth the well is drilled or when the decision is made to plug the well. After final well construction, no mud will be used; since a clean completion fluid, such as 2-3 % KCl completion water will be present.

Prior to completely abandoning the hole during any part of the drilling process, partial abandonment will be considered and the well may be sidetracked to prevent total loss of the work completed to that point.

4.3 Abandonment Post-Injection

All casing placed and used in this well will be cemented to surface and will not be retrievable at abandonment post-injection. After injection is ceased and well pressure has stabilized, the well will be flushed with brine or fresh water to displace the injectate into the formation. The injection tubing and injection packer will be the only injection equipment remaining in the cased hole. Attempts will be made to remove the injection tubing and packer, however, if the packer cannot be released and/or removed from the cased hole, a wireline tubing cutter will be used to cutoff the tubing above the single packer. A series of balanced cement plugs will be used to fill the entire well with cement for final abandonment.

The attached table provides a summary of the proposed borehole areas where cement plugs will be required and are necessary for final injection well plugging and abandonment.

5.0 Cement Type and Volume Calculations

In addition to selecting the proper cement type, and performing calculated cement plug volumes, the specific cement placement will be implemented according to the cement plug depths in the proposed plugging plan, and as approved by US EPA. All cement used will be previously tested in the lab, an analysis will be performed using specific well information such as actual well depths, bottomhole temperature and borehole conditions. During the plugging operations, both wet and dry samples will be collected for each plug spotted to ensure quality of the plug. All casing will be cemented to surface and no casing will be retrieved. From the surface, the casing strings will be cutoff to at least 3 feet below ground, well below the frost and plow line and a blank steel plate with the required permit information will be welded to the top of the cutoff casing as a cap.

Cement volumes calculations will be performed for specific abandonment of the injection wellbore environment as based on desired plug diameter and length required for post-injection.

1. Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.

2. Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

3. See generic calculation formulas in Attachment 4 and have a cementer and wellsite supervisor both review calculations prior to spotting any plug.

Note: For each cementing operation the cement vendor and the wellsite supervisor will verify via the cementing handbook all calculations and have the Project Manager approve the manner and procedure for said cementing operations. Any amendments to the plugging program will require an exemption approved in writing from the Project Manager.

6.0 Proposed Plug and Abandonment Plan Overview

Following the final logging the entire open hole section the well will be permanently abandoned. The plugging will be done by spotting balanced cement plugs (see attached schematics) in appropriate lengths through the entire well. The top of each plug will be verified prior to setting another plug on top. With a robust protective casing design present in these TEC injection wells, using multiple strings to protect lowermost USDWs, oil and gas bearing formations, and the CO_2 injection interval the proposed plugging program for these wells is straightforward and protective.

The casings will be cut off 3 feet below the ground level and a plate (with well name and date) will be installed on the cut portion of the 30-inch x 20-inch x 13-3/8-inch x 9-5/8-inch casing. The location will then be cleaned up and the land restored.

7.0 Detailed Pre-Plugging and Abandonment Procedures

The following Notifications, Permits, and Inspections will be performed prior to Workover or Rig mobilization. Pending the granting of all approvals and final plugging program, TEC will provide a completed contact list for reporting to US EPA as part of process to plug and abandon the well, and allow US EPA to either witness or oversee operations as needed to insure compliance.

Plugging & Abandonment Contact List

Name	Depart./Position	Office	Pager	Mobile	Home
	Cementing Operations				
TEC	Project Management				
TEC	Project Engineer				
	Operations Superintendent				
	State Regulatory				
	Federal Regulatory				

Note: This table will be completed prior to plugging the wells and will be provided to US EPA, along with the final logging results and downhole pressure measurements at least 30 days prior to plugging the well.

7.1 Detailed Pre-Plugging Procedure:

1. Notify US EPA 30 days via letter of intent, and 48 hours prior to commencing field operations. Insure proper notifications and permits are in place and given to all regulatory agencies for rig move.

2. Insure all permits for P&A procedure and work plan have been approved and work authorized by all local, State & Federal agencies.

3. Ensure that advance pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.

4. Provide on-site and at well location all copies of permits prior to initiating operations. Monitor and insure all permit conditions of approval have been met.

5. Make sure all necessary forms for TEC are on the rig, i.e., NPDES, safety meetings, trip sheets, etc.

7.2 Detailed Plugging and Abandonment Procedure (Post-Injection)

1. Mobilize workover (WO) or Plugging Rig Equipment

2. Inspect and rig up workover rig and all auxiliary equipment. Nipple up blowout preventers and pressure test. Perform safety check and inspection on all equipment.

3. Determine well status (i.e. Is tubing plugged with blanking plug? Is tubing full of kill weight fluid? Is annulus full of kill weight fluid? etc.)

4. If tubing is plugged with a blanking plug then rig up slickline and pull same from well being very careful to follow proper well control procedures.

5. If packer can be retrieved then release packer and pull out of hole. If packer is seal bore type then pull out of hole with seal assembly and pick up retrieving tool and trip back in hole to retrieve packer. If packer can be retrieved then proceed as follows. If packer cannot be pulled then pull out of hole with tubing and pick up smaller work string to pass through packer bore.

6. With a work string, trip in hole to total depth. Circulate well with kill weight brine and establish good circulation. Drilling mud can be substituted for brine as long as proper density is maintained. Prepare to plug well using balanced plug method with first plug from total depth – 6600 feet. Mix and pump 275 sacks of Class H cement with proper additives at 15.8 ppg. Spot plug with correct displacement and pull tubing to 6000 feet. Reverse circulate tubing and shut well in overnight.

7. After letting cement set overnight trip back in hole and tag up on cement plug. Continue to plug well by setting +/-500 foot plugs using balanced plug method. After three plugs in a row are set pull tubing 500 feet above last plug and reverse circulate tubing. From 6000 – surface a total of 12 plugs will be needed to plug well to surface. Each plug inside the 9-5/8 inch casing will need to be approximately 180 sacks Class H cement with proper additives. As each plug is set the work string will be laid down as being pulled.

8. Plug well with a total of approximately 2135 sacks of Class H cement and proper additives. On last plug at surface nipple down BOPs and remove well head. Cut off casing as low as possible and weld plate on top with well name and any other pertinent information as a permanent marker.

9. Rig down and move out all equipment. Return location to original contour and reseed using local native grasses.

8.0 Cost estimate for Plugging and Abandonment (worst case) Scenario

Itemized Plug and Abandonment Costs	During Drilling & Construction	Post-Injection Construction
a. Casing Evaluation:	N/A	$25,000
b. Evaluation of any problems discovered by the casing evaluation:	N/A	$20,000
c. Cost for repairing problems and cleanup of any groundwater or soil contamination:	N/A	$20,000
d. Cost for cementing or other materials used to plug the well:	$37,000	$150,000
e. Cost for labor, engineering, rig time, equipment and consultants:	$157,000	$150,000
f. Cost for decontamination of equipment:	N/A	N/A
g. Cost for disposal of any equipment: Tubing would be sold as scrap metal and worst case cost would be trucking services only.	N/A	$2,000
h. Estimated sales tax: Our review shows there is no state sales tax for this kind of work.	$2,000	$2,000
i. Miscellaneous and minor contingencies (20%):	$10,000	$10,000
j. Total	$206,000	$379,000

Note: if the well was abandoned following 30 years of operations, Year 2045, then assuming 3 % annual inflation rate the worst case P&A cost would be 2.43 times greater or ~$920,970 per well.

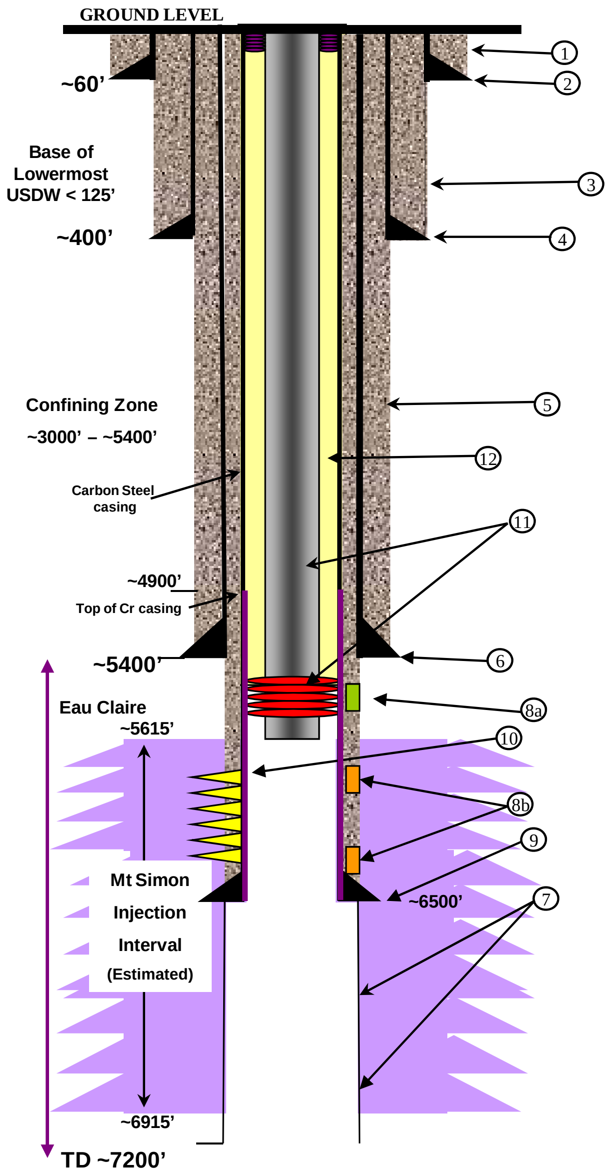
December 9, 2009

Christian County Generation, L.L.C. (CCG)
TEC #1-Injection Well
[Taylorville Energy Center]
Christian Co., IL
Proposed Well Design Schematic

Proposed Location:
Sec. 12 T 13 N R 2 W

Status: Proposed

Elev. 610 '
KB' = ?



Well Total Depth 7200'

1. Optional: Drill 36-inch borehole to ~60 feet
2. Set 30-inch conductor casing (optional) to TD, circulate cement to surface
3. Drill 26-inch borehole to ~ 400 feet
4. Set 20-inch Surface casing (94 lb/ft H-40 STC) to TD, circulate cement to surface

Perform Leak-off test or Formation Integrity Test at casing shoe area.

5. Drill 17-1/2-inch borehole to ~5,400 feet
6. Set 13-3/8-inch intermediate protection casing (using 61, and/or 68 lb/ft J-55 STC) to section TD, cement to surface.

Run Cement Bond Log to demonstrate Isolation and borehole Integrity

Perform Leak-off test or Formation Integrity Test at casing shoe area.

7. Drill 12-1/4-inch hole from TD to ~7200 feet.
8. Take 3 conventional whole cores, (30 feet) 4-inch core in: a. - Eau Claire Shale,
   b. - Mount Simon sandstone.

Run openhole logs, evaluate Mount Simon reservoir.

9. Set 9-5/8-in production casing from surface to design depth; cement to surface. [Note: Cr casing may be used across packer interval and at TD of 9-5/8-in casing shoe.]
10. Well completion interval based on evaluation of field data
11. Set Injection packer, 5.5 or 7-inch tubing and hanger @ ~ 5,300 feet across lower Eau Claire section.
12. Fluid-filled Annulus monitoring system.

Final Well Completion:

Cased intervals to include centralizers; with the number and location based on hole deviation surveys.

Flexibility Option also exists to complete the well in open-hole completion form to enhance reservoir and avoid formation damage, etc.

Set Injection Packer, Tubing, Annulus system; Demonstrate Mechanical Integrity Testing.

Test Mount Simon Sandstone Injection Interval.

Attachment 1. Injection Well Proposed Design Schematic – based on TEC #1

Attachment 2 Information on formations, depths to USDW, etc

Expected Depths for Key Formations at TEC Site

Formation	Expected Depth (GL- ft)	Expected Depth (KB) - ft	Estimated Thickness ft	Lithology	Comments
Ground Level	0	15			substructure
Soil/Overburden	50	190	140	glacial till	USDW
New Albany	**1830**	**1845**	**120**	**shale**	**Sealing unit**
Maquoketa	**2560**	**2575**	**525**	**shale**	**Secondary seal**
Trenton Black River				limestone	
Dutch Town				dol-ls	
St Peter	3100	3115	200	qtz arenite	Observation Interval
Knox	3400	3415		dolomite	non-por-Por intervals
Eau Claire	**5115**	**5130**	**215**	**sh/ss/ls/dol**	**Primary Sealing unit**
Mount Simon	**5615**	**5630**	**1300**	**sandstone**	**Injection Interval**
Precambrian	6915	6930	285	Granite	Igneous
Total Depth	7200	7215			

(yellow)	Proposed Injection Interval
(light purple)	Primary Confining Seals
(green)	Secondary Confining Seals

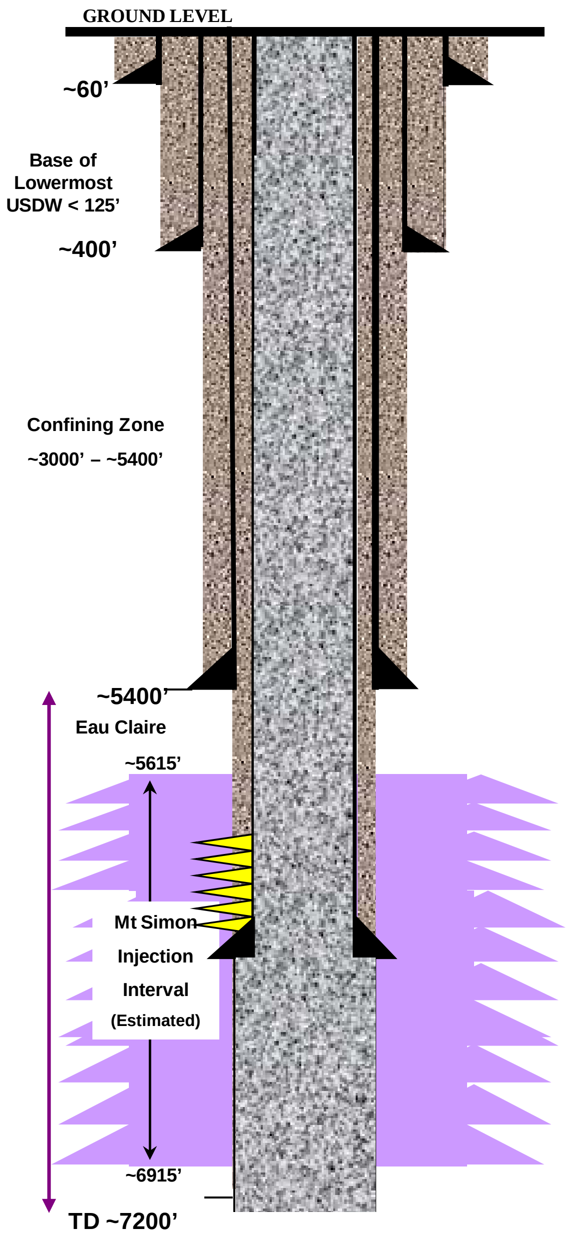
December 9, 2009

Christian County Generation, L.L.C. (CCG)
TEC #1-Injection Well
[Taylorville Energy Center]
Christian Co., IL

Proposed Location:
Sec. 12 T 13 N R 2 W

Proposed Well Plugging Schematic
Status: Proposed P&A

Elev. 610 '
KB' = ?



Well Total Depth ~7200'

Final Well Plug and Abandonment:

Place Cement Plug across Mount Simon Sandstone injection interval. Tag plug for integrity, test casing.

Place Cement Plugs in 500 foot sections from top of injection interval to surface. Tag plugs for integrity, test casing.

Cut 30-inch, 20-inch, 13-3/8-inch, 9-5/8-inch below ground level.
Install cap/plate on casing stub per IL O&G regulations.

Attachment 3. TEC Injection Well Proposed Plug & Abandonment Design Schematic – based on TEC #1

TEC #1-Injection Well P&A Configuration

Sandia Technologies, LLC

Attachment 4

GENERIC CEMENT, ANNULAR and BOREHOLE VOLUME

EQUATIONS AND CALCULATIONS

Attachment 4 Plugging Volume Calculation Worksheet – page 1

VOLUME CALCULATIONS

1. CAPACITIES

Determine the following capacities:

Annular capacity between drillpipe and hole (V_{ANN})	ft^3/ft and ft/bbl
Hole or casing capacity (V_{CAPOH})	ft^3/ft
Drillpipe or tubing capacity (V_{CAPDP})	ft^3/ft and bbl/ft

2. NUMBER OF SACKS OF CEMENT

Determine the number of sacks of cement required for a given length of plug (sx):

$N_{SX} = L_{PLUG} \times V_{CAPOH}$ / slurry yield

Where:

N_{SX} = number of sacks of cement, sx

L_{PLUG} = length of cement plug, ft

V_{CAPOH} = capacity of open hole or casing, ft^3/ft

Slurry yield = cement yield, ft^3/sk

3. SPACER VOLUME BEHIND SLURRY

Determine the spacer volume to be pumped behind the slurry to balance the plug (bbls):

$V_{TAILSPACER} = V_{ANN} \times V_{LEADSPCR} \times V_{CAPDP}$

Where:

$V_{TAILSPACER}$ = spacer volume to be pumped behind the slurry to balance the plug, bbls

V_{ANN} = annular capacity, ft/bbl

$V_{LEADSPCR}$ = spacer volume to be pumped ahead of cement plug, bbls

V_{CAPDP} = drill pipe capacity, bbl/ft

VOLUME CALCULATIONS, CONTINUED

4. PLUG LENGTH

Determine the plug length (ft) before the drill pipe is withdrawn (ft):

L_{PLUG} = (N_{SX} X slurry yield) / (V_{ANN} + V_{CAPDP})

Where:

L_{PLUG} = length of cement plug before the DP is withdrawn, ft

N_{SX} = number of sacks of cement, sx

Slurry yield = cement yield, ft^3/sk

V_{ANN} = annular capacity, ft^3/ft

V_{CAPDP} = drill pipe capacity, ft^3/ft

5. LENGTH OF FREEFALL IN DRILL PIPE

Determine the length of mud free fall in drill pipe (ft):

L_{FF} = TD (1 – MW)

Where:

L_{FF} = length of free fall inside the drill pipe, ft

TD = depth, ft

MW = mud density, pPG

6. DISPLACEMENT VOLUME

Determine displacement volume required to spot the plug (bbl):

V_{DISP} = [(L_{DP} – L_{PLUG} – L_{FF}) X V_{CAPDP}] – $V_{TAILSPCR}$

Where:

V_{DISP} = displacement volume required to spot cement plug, bbls

L_{DP} = length of drill pipe, ft

L_{PLUG} = length of cement plug, ft

L_{FF} = length of freefall, ft

V_{CAPDP} = drill pipe capacity, bbl/ft

$V_{TAILSPCR}$ = spacer volume to be pumped behind the slurry to balance the plug, bbls

PISC and Site Closure Plan

1.0 Facility Information

Facility Name:	Taylorville Energy Center
Applicant Name:	Christian County Generation, L.L.C., 1044 N 115 St., Suite 400, Omaha, NE 68154-4446
Facility Contacts:	Ryan Choquette, Manager, Midstream Engineering, Ph. 402-938-1641, e-mail rchoquette@tenaska.com
Location:	1630 N 1400 E Road, Taylorville, Christian County, IL 62568

2.0 Pre- and Post-Injection Pressure Differential

The Area of Review (AOR) boundary is based on a pressure differential of approximately 180 psi and was derived from MESOP calculations and preliminary site modeling (see Area of Review and Corrective Action Plan). Modeling shows that following the end of injection, the pressure boundary ceases to expand and pressures begin to return to pre-injection levels.

2.1 Predicted Position of the Carbon Dioxide Plume and Associated Pressure Front at Site Closure

Preliminary modeling, under the four-well case was used to find the AOR boundary with the pressure front. Figure 1 provides the map view position of the CO_2 after 30 years of injection. Figure 2 shows the position of the CO_2 15 years after the end of injection and shows that reservoir pressures are below 180 psi except for the areas immediately adjacent to the injection wells. Figures 1 and 2 also emphasize that the CO_2 is not expected to move significantly in the post-injection period. The Mt. Simon reservoir is nearly flat-lying and therefore buoyancy forces and resultant CO_2 movement are not expected to be significant.

Upon completion of TEC #1, the data from that well will be used to update the site model and to re-evaluate the AOR and closure scenarios. The AOR boundary and post-injection site conditions will also be updated, if needed, at each 5-year site evaluation.

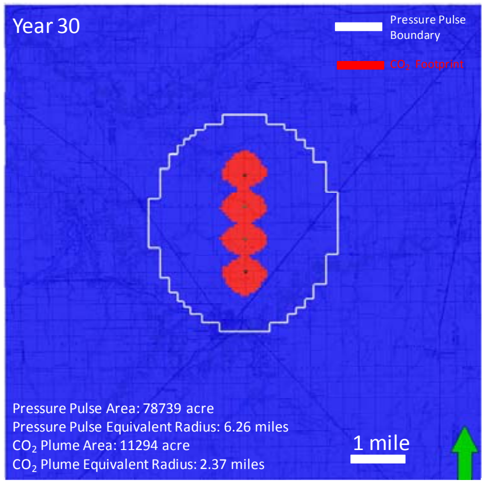


Figure 1

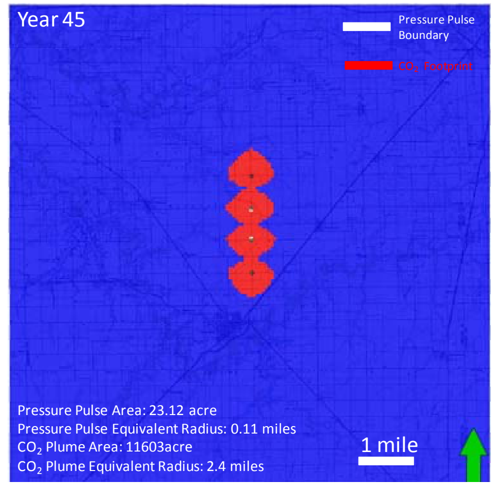


Figure 2

3.0 Post-Injection Monitoring Plan

3.1 Groundwater Quality Monitoring

Groundwater quality monitoring sampling procedures, analytes, laboratory procedures, and (quality assurance) QA requirements and methods will be the same in the post-injection period and are described in the Testing and Monitoring Plan.

Groundwater quality monitoring will continue to focus on the site's lowermost USDW and the St. Peter monitoring well; the monitoring program will be defined during initial site characterization (i.e. installation of TEC #1). Based on available information, the shallow zone is expected to be within 250 feet of ground surface and includes the unconfined aquifer situated in the glacial sediments present at the site. Figure 3 shows a schematic of site monitoring well locations.

As noted above, sampling methods, analytical techniques, chain of custody procedures, QA and surveillance measures will remain the same as those described in the Testing and Monitoring Plan. The choice of analytical laboratory for the post-injection period is to be determined; the selection of the laboratory will be based on their ability to provide the analytical methods and associated accuracy and precision requirements for the methods established in the Testing and Monitoring Plan.

Property has been optioned for TEC #1 at the plant site and TEC #3, four miles north of the plant site. Additional agreements for TEC #2 and TEC #4 will be executed contingent on final permitting, approval, funding for the TEC project, and test results for TEC #1. The shallow monitoring wells will be installed on the same parcel as the injection wells. The monitoring wells will be offset from the injection wells to avoid damage to either the injection well or the monitoring well and to assure safe access to each well for operations and maintenance.

Monitoring and reporting frequency will be adjusted in the post-closure injection period:

Shallow Wells

- Continue with quarterly monitoring for the first five years after end of injection
- Annual monitoring thereafter through site closure.
- Annual reporting until site closure

St. Peter Well

- Annual fluid sampling through year 5
- Report at year 5
- Fluid sampling and reporting at year 10
- Fluid sampling and reporting every 10 years until site closure.

3.2 Carbon Dioxide Plume and Pressure Front Tracking

3.2.1 Direct Pressure Monitoring

Reservoir pressures will continue to be measured and recorded in the same manner and with the same type of equipment as used during injection monitoring (see Testing and Monitoring Plan). The in-zone well will be monitored during the initial part of the post injection closure period. As noted above, as soon as injection operations are ended, reservoir pressures begin to decline. The in-zone well will be monitored and maintained for at least the first five years following the end of injection. Once formation pressure differential is at approximately 10% of the AOR boundary pressure, TEC will notify US EPA that it intends to decommission, plug, and abandon the in-zone monitoring well. For example, if the AOR boundary is set at a pressure differential of 180 psi, then TEC would request well closure when the pressure differential at the monitoring well is at (or below) 18 psi.

Well Location/Map Reference	Depth(s)/Formation(s)	Frequency
Injection Wells	Mt. Simon	Continuous through well closure
In-zone monitoring well	Mt. Simon	Continuous until wells P&A
St. Peter monitoring well	St. Peter sandstone	Continuous through injection operations

3.2.2 Quality assurance surveillance measures

The well gauge will be calibrated prior to installation and then calibrated subsequently according to manufacturers specifications. The data will be evaluated monthly and examined for trends, sudden changes in pressure, or other statistical anomalies in the data. The data and analyses will be included in permit-required operating reports.

3.2.3 Plan for guaranteeing access to all monitoring locations

The locations for the in-zone monitoring well have not been determined at this time, therefore no land or access rights associated with the well have been acquired. Once TEC #1 is installed and the revised AOR is developed, the location of the in zone wells will be identified and TEC will acquire site access. TEC will maintain control of the injection well locations through the post-injection site care period.

3.2.4 Indirect Carbon Dioxide Plume Tracking

The method(s) devised for indirect CO_2 tracking during the injection operation phase of the project will continue during the post-injection period. If 3D Seismic surveys are utilized, they would be completed in the post-injection phase using the same design as during the operational phase (Figure 3).

Site surveys will be repeated at five year intervals for the first 10 years of post closure car (i.e. at year 5 and at year 10) and then every 10 years thereafter, until site closure. Results of the site survey and a summary of all post-injection monitoring data, collected during the period will also be included in each report. The site reservoir model will be updated as needed and the predicted size and shape of the pressure boundary and position of the CO_2 from the previous model will be compared to the updated model.

3.3 Proposed Schedule for Submitting Post-Injection Monitoring Requests

The post injection monitoring overview and reporting schedule is provided on Table 1

4.0 Alternative Post-Injection Site Care Timeframe

Based on preliminary modeling, TEC expects that reservoir injection pressures will return to pre-injection pressures in less than 50 years following the end of injection. Modeling also shows that the CO_2 is not expected to move significantly following the end of injection. Therefore, it is likely that TEC will request an alternate post-injection site care timeframe that will be based on post-injection monitoring data and the updated reservoir model.

The request for site closure will be made at the time that TEC can demonstrate that there is substantial evidence that the project no longer poses a risk of endangerment to USDWs.

5.0 Site Closure Plan

5.1 Planned Remedial/Site Restoration Activities

Plugging plans for the injection wells and monitoring wells are established in the Injection Well Plugging Plan. These same procedures and design will be applied to the in-zone monitoring wells. Note that cement volumes will be adjusted for the as-built condition of the wells. In general, well surveys and an updated design will be completed at each well and a request for well closure will be submitted to US EPA. Upon approval, TEC will mobilize the necessary equipment and supplies to the site and plug and abandon the wells in accordance with the approved design. Surface equipment will be removed and the site will be restored to its prior condition.

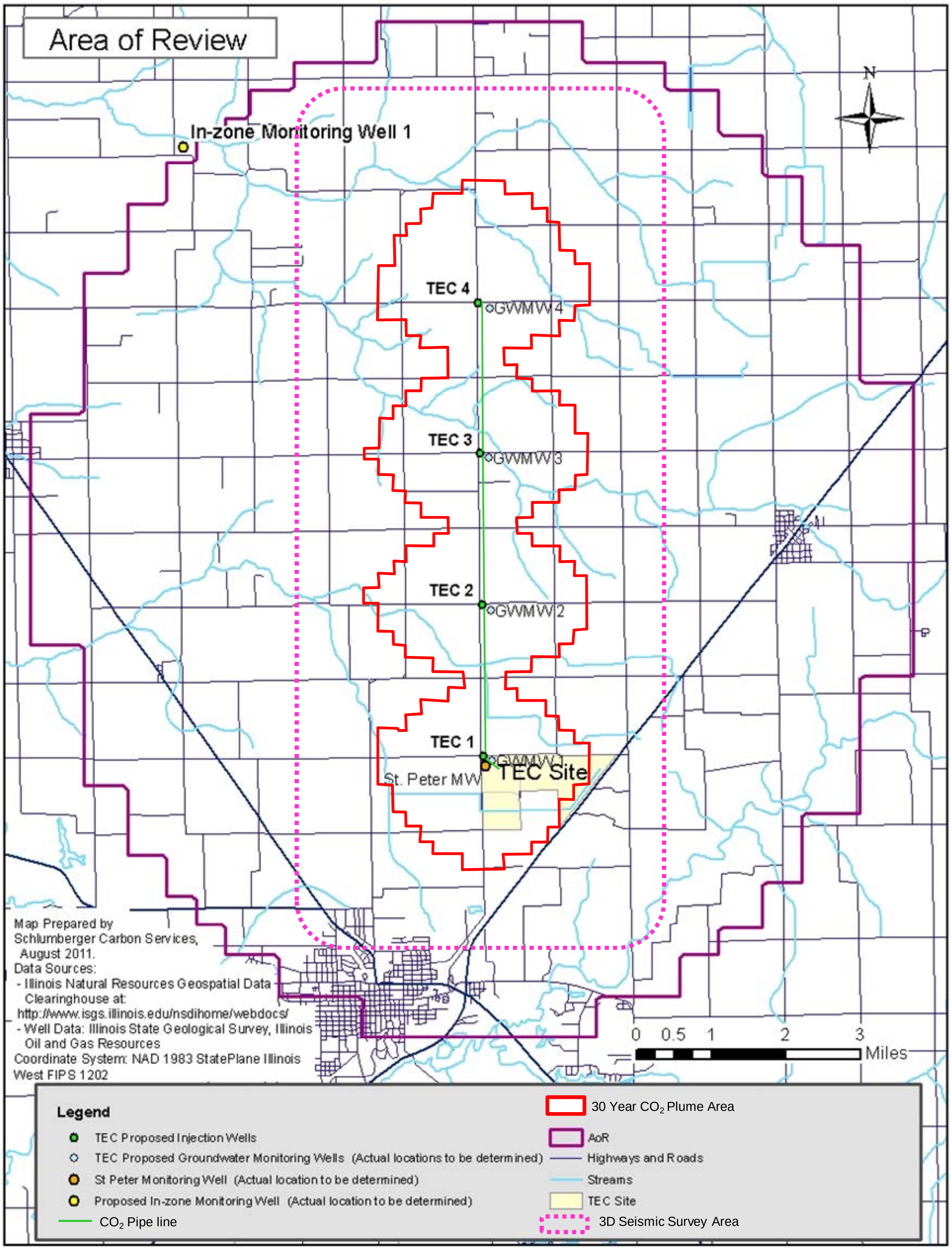


Figure 3 Monitoring well locations and seismic survey area.

Monitoring Point	During Injection	Post Injection Site Care (See Post Injection Site Care and Site Closure Plan for details)		
		Years 1 to 5	Years 6 to 10	Thereafter until closure
CO_2 Injectate	Quarterly sampling; annual reporting	None	None	None
Shallow (USDW) Monitoring Wells	Quarterly sampling (annual reporting)*	Quarterly sampling (annual reporting)*	Annual sampling and reporting	Annual sampling and reporting
St. Peter Well	Continuous pressure; annual fluid sampling for years one through 5 then every five years thereafter. Report every five years*	Annual fluid sampling; reporting at year 5	Fluid sampling and reporting year 10	Fluid sampling and reporting every 10 years
In-Zone Monitoring Well	Continuous pressure; report every five years*	Continuous until pressure declines to within 10% of AOR pressure boundary differential. Report at year 5	Continuous until pressure declines to within 10% of AOR pressure boundary differential. Report at year 10	Continuous until pressure declines to within 10% of AOR pressure boundary differential. Report every 10 years
Injection Well	Continuous pressure, temperature, flow. Annual MIT Monthly reporting	Continuous pressure. Annual MIT Report at year 5.	Continuous pressure. MIT at year 10 or at well closure Report at year 10.	Continuous pressure. MIT every 10 years Report every 10 years or until well closure.
Pipeline	Continuous temperature and flow. Reporting every five years*	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection
Corrosion Coupons	Coupon sampling and reporting every five years	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection	None – Pipeline to be closed at end of injection
Injection Well Annulus	Continuous pressure. Monthly reporting	Continuous pressure; report at year 5	Continuous pressure; report at year 10 or at well closure	Continuous pressure and report every 10 years or until well closure.
Indirect Monitoring	Survey and report every five years	Survey and report at year 5	Survey and report at year 10	Survey and report every 10 years until closure

* If statistically significant changes or anomalous data are noted before a permit-scheduled reporting interval, TEC will notify US EPA within 30 days of the receiving interpretation or analytical results.

Table 1 Monitoring activity and reporting frequency.

Emergency and Remedial Response Plan

1.0 Facility Information

Facility Name: Taylorville Energy Center

Applicant Name: Christian County Generation, L.L.C., 1044 N 115 St., Suite 400, Omaha, NE 68154-4446

Facility Contacts: Ryan Choquette, Manager Midstream Engineering,
Ph. 402-938-1641,
e-mail rchoquette@tenaska.com

Location: 1630 N 1400 E Road, Taylorville, Christian County, IL 62568

2.0 Operational Contingency Plans

Contingency plans will be in place to identify situations where potential plant and/or process upset conditions may occur and take appropriate measures which are protective to the local area and the environment by shutting in the wells and monitoring their pressure falloff. Operational contingency plans for all Taylorville Energy Center (TEC) injection wells include potential downtime periods when annual Injection Well Testing, maintenance, well service, and stimulation occur. These plans include the following:

- Annual Testing of one well at a time, monitoring via sensors, downhole and on surface;
- Sensors to detect malfunctions and potential leaks;
- Three (potentially four) Injection Wells would be on the site and in place during testing.

With multiple wells (up to four wells are planned) under the Permit. Mechanical Integrity Tests (MIT) will be performed using U.S. EPA Region 5 guidelines for MIT and bottomhole pressure testing (U.S. EPA Region 5 Guidance). Additionally, bottomhole pressure falloff tests could be completed on one well at a time, while the other well continues in normal operation. This is likely since the wells are sufficiently distant (~2-miles apart) where limited interference will occur within a good to excellent Mount Simon Sandstone injection interval.

The availability of multiple wells and adhering to proper TEC operations practices, including regular well maintenance and service, will reduce most injection well down-time and should eliminate the unlikely occurrence of two or more wells being simultaneously unavailable for use. In the unlikely event that all wells are temporarily unavailable or are out of commission, the CO_2 will be vented to the atmosphere for that limited period until operations and injectivity are re-established.

2.1 Compressor

CO_2 will be compressed using two 50% capacity 8 stage integrally geared centrifugal compressors. Each compressor will be driven by an approximately 19,500 horsepower electric motor. The compressors will be equipped with intercoolers and after coolers to prevent excessive discharge temperatures. Flows and pressures will be controlled by inlet guide vanes using suction and discharge pressures as control points. In the event the inlet guide vanes are at the maximum travel distance, the system will recycle or vent CO_2 to prevent an over or under pressure situation. The compressor will have an emergency shutdown system. In the event a line leak or and overpressure situation is detected, the emergency shutdown system will be activated to shut off flow of CO_2 to the pipeline.

2.2 Corrosion Monitoring

An internal corrosion monitoring program that meets ASTM requirements (Designation G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens) will be use on the pipeline and the injection wells. Weight loss coupons or electrical probes will be installed to monitor corrosion. Two coupons or probes will be installed at each injection well site. One coupon will be in the flow line. The other coupon will be located on the wellhead. The coupons will be held in place using industry standard coupon holders. The coupons will be monitored twice each calendar year, at intervals not exceeding seven and one half (7½) months. The coupons will be cleaned, inspected, and weighed per ASTM G1 standards. All weights will be taken with an accuracy of +/- 0.1 of a milligram. The weight will be recorded. The weight will be used to calculate the corrosion rate in mils/year. If the coupons are found to have more than 3 mils/year of loss, corrective action will be taken. Potential actions could include a review to verify no water is in the system and the use of corrosion inhibitors. When corrosion is over the 3 mils per year limit, the coupons will be monitored more frequently. Whenever a pipeline or tubing section is removed, an inspection of the internal surface of all pipelines for corrosion will occur. If extensive internal corrosion exists a review of the pressure capability of the pipe and tubing will be conducted. If the corrosion has reduced the wall thickness of a segment less than that required for the maximum allowable operating pressure, the pipe will be replaced or working pressure reduced.

2.3 Pipeline, Injection Well, and Annulus Pressure

The maximum (surface) injection pressure is limited by the maximum design pipeline pressure which is 2220 psia. For the purposes of developing the injection modeling, a maximum surface top-hole pressure of 2100 psia was used. The maximum surface injection pressure will be determined based on actual site conditions but will not exceed the pipeline design pressure. Depending on the number of wells needed at the site, the modeling indicates that average injection pressures are expected to range from 1600 to 1800 psia.

All meter, pressure and temperature reading will be connected to a flow computer. The flow computer will then calculate and record flow volumes, pressure flowing pressure, wellhead pressure, annulus pressures, and temperature readings. The readings will be transmitted to the TEC plant. The flow computer will use the flow, pressure, and temperature data to control the control valve and wellhead shut off valve. In the event where pressure is at maximum allowable injection pressures the controls system will reduce flows to prevent well head pressures from exceeding maximum allowable pressures. If the flow is reduced to less than 10% of maximum flow, the well will shut in. In the event annulus pressures exceed 50 psig, a high pressure alarm will be triggered and the cause investigated. When annulus pressure exceeds 500 psi the well will be shut in. More details regarding the proposed annular pressure monitoring system are included in Section 4.16 of the Technical Report.

The flow computer will be powered by commercial power. The flow computer will have a battery back-up system to supply power in the event of a power outage. The batteries will be sized for a minimum of 24 hours of operation without commercial power. A disconnect will be installed to allow for connection of an emergency backup generator to recharge the batteries. If there is an electronic system failure lasting longer than 24 hours, pressure readings will be taken and recorded every 8 hours (visual reading from meters by TEC staff) and flows will be estimated. The data will be plotted and included in the injection report.

The injection well will use an orifice, coriolis, or an ultrasonic meter to measure and record the volume of CO_2 flowing to the well. The meters will be installed per manufacture and industry standards for a resulting meter accuracy of +/-2%. The high pressure transmitter will be a Rosemount 3051 S1_T4A or equal. The transmitter has a range of -14.7 to 4000 psig. The transmitter will be adjusted for a span of 0 to 3000 psia with an accuracy of +/-2.89 psi. The annulus pressure transmitter will be a Rosemount 3051 S1_T2A or equal. The transmitter has a range of -14.7 to 150 psig. The transmitter will be adjusted for a span of -14.7 to 75 psig with an accuracy of +/-0.11 psi. Temperature transmitter will be a

Rosemount 3144P 4 wire 100 ohm platinum RTD or equal. Possible span, -200 to 800 C with and intended span of -40 to 100 C. Accuracy will be +/-.37C. If an orifice meter is used, a Rosemount 3051S Multivariable Transmitter will be used for pressure, differential, and temperature measurement. Pressure and temperature accuracy will be equal to standalone transmitters. Differential accuracy will be +/- 0.045% of DP reading. All transmitters will use stainless steel or better construction on wetted parts to avoid corrosion issues.

3.0 List of Resources/Infrastructure

- CO_2 Capture and compression systems (located at power generation facility)
- Up to four injection wells (injection zone approximately 5615 ft. to 6915 ft. below ground surface) and well head. (Actual number and location of injection wells to be determined.)
- CO_2 pipeline (buried)
- Monitoring wells (Actual number and location of in-zone and lowermost USDW monitoring wells to be determined.)
- Taylorville (approximately 2 miles SW of TEC; approximately 3 miles from nearest injection well)
- Monitoring and SCADA systems
- Surface Water – Sangamon River approximately 3 miles SE of nearest injection well
- USDW within glacial drift (ground surface to 400 feet)

3.1 Events and Response Actions

Potential adverse events and potential response actions that consider the project infrastructure and resources are listed below. Risk level is based on the likelihood of occurrence.

Infrastructure: Injection well (Figure 1))

Potential adverse event #1: Damage to well head; well head failure
Risk Level: Moderate
Potential response action(s): Well taken off line automatically
Response personnel: TEC plant personnel
Equipment: Isolate and evacuate the area near the well. Determine safe distance and set a perimeter by using a hand-held air quality monitor (O_2, CO_2). Note wind direction. Other equipment needed for maintenance and repairs to be determined based on event.
Potential adverse event #2: Well bore leakage
Risk Level: Low

Potential response action(s): Shut in well at wellhead; cease injection until problem is corrected
Response personnel: TEC plant personnel
Equipment: Valves operate automatically at loss of pressure (valves also may be operated manually.) Other equipment needed for maintenance and repairs to be determined based on event.

Potential adverse event #3: Pipeline damage
Risk Level: Low
Potential response action(s): Compressor and pipeline taken off line; shut in well at wellhead; cease injection until problem is corrected.
Response personnel: TEC plant personnel
Equipment: Valves and compressor shutdown operate automatically at loss of pressure (valves also may be operated manually.) Other equipment needed for maintenance and repairs to be determined based on event.

Resource: USDW

Potential adverse event #1: Observe statistically changed CO_2 and/or other indicator parameters in USDW ground water samples.
Risk Level: Low – wells are located geologically downgradient of the injection zone. And, based on site model, CO_2 plume will not extend underneath the well field.
Potential response action(s): Notify US EPA; Resample wells for confirmation
Response personnel: TEC personnel, subcontractor
Equipment: Sampling equipment (pumps, bailers, containers, sample containers, etc.)

Potential adverse event #2: Confirmed movement of CO2 into USDW
Risk Level: Low
Potential response action(s): Stop injection; Assess remedial options and implement corrective action
Response personnel: TEC personnel; subcontractor(s)
Equipment: To be determined based on corrective action.

Resource: Taylorville water supply (Figure 1)

Potential adverse event #1: CO_2 reaches the municipal well supply
Risk Level: Very Low
Potential response action(s): Confirm presence of CO_2 in wells; stop injection; assess remedial options and implement corrective action
Response personnel: TEC, Taylorville, subcontractor
Equipment: To be determined based on corrective action.

4.0 Staff Training and Exercise Procedures

The CO_2 infrastructure and injection system will be operated as part of the TEC. Plans for site-specific training, health and safety, and emergency response will be developed along with operating and maintenance (O&M) documents for TEC. At this time, much of the design has yet to be completed and therefore these documents have not been created. Note that complete documents will be submitted to US EPA along with a well completion report and revised geologic report/AOR following completion of the first injection well and following the decision to continue with the injection phase of the project.

Training Plan Components:

- Develop O&M documents
- Identify staff who will be operating the CO_2 injection system
- Location and inventory of response equipment
- Notification and contact information.

5.0 Communications Plan and Emergency Notification Procedures

5.1 List emergency response contact(s) and role(s)

Contact	Organization	Role
TEC Security	TEC	Initial point of contact for all injury accidents. TEC security will make all contacts with Taylorville emergency responders (911)
TEC Plant Manager	TEC	Overall site management; initial point of contact for all non-injury site emergencies
TEC Shift Supervisor	TEC	Coordinate with plant manager; initial point of contact when Plant Manager is off site
Christian County Emergency Dispatcher	Christian County Emergency Operations Center or Christian County Emergency Management Agency (217-820-0912)	Coordinate emergency response as needed

5.2 Communication Plan

TEC will establish an operations and communication plan at the time the facility is developed (see discussion in Section 4.) The plan will provide details on the line of communications for emergency response at the site. The plan will include individual names, roles, responsibility, and contact information for TEC management, emergency responders, and equipment and service providers. The plan will also identify key stakeholders and groups in the areas and communities within and adjacent to the AOR.

TEC will coordinate plan development with the Christian County Emergency Management Agency (CCEM). CCEM has developed emergency plans for natural and other disasters. These plans include:

- Emergency response plans for release/potential release of hazardous or toxic materials
- Evacuation routes
- Coordination of fire and emergency responders
- Maintenance of local and a state-wide inventory and location of emergency response equipment
- Comprehensive fire protection plan for Christian County
- List of emergency potable water providers
- Mass e-mail lists
- Location of vehicle-mounted public address systems

When public notice is required, local media may be contacted. Local media contacts include:

Radio

WTIM 97.3 FM, WMKR 94.3 FM, and WRAN 98.3 FM

918 E. Park, Taylorville IL. 62568

824-3395

Newspaper

Breeze Courier

212 S. Main Taylorville IL. 62568

217-824-2233

State Journal Register

One Copley Plaza, Springfield IL. 62701

217-788-1513 (newsroom)

sjr@sj-r.com

Television:

WICS Television

2680 Cook St. Springfield IL. 62707

217-753-5656 or 217-753-5660

WAND Television

05 South Shore Drive Decatur IL. 62541

John McCall news director (cell) 521-3701; (home) 875-0076

424-2583 (fax)

news@wandtv.com

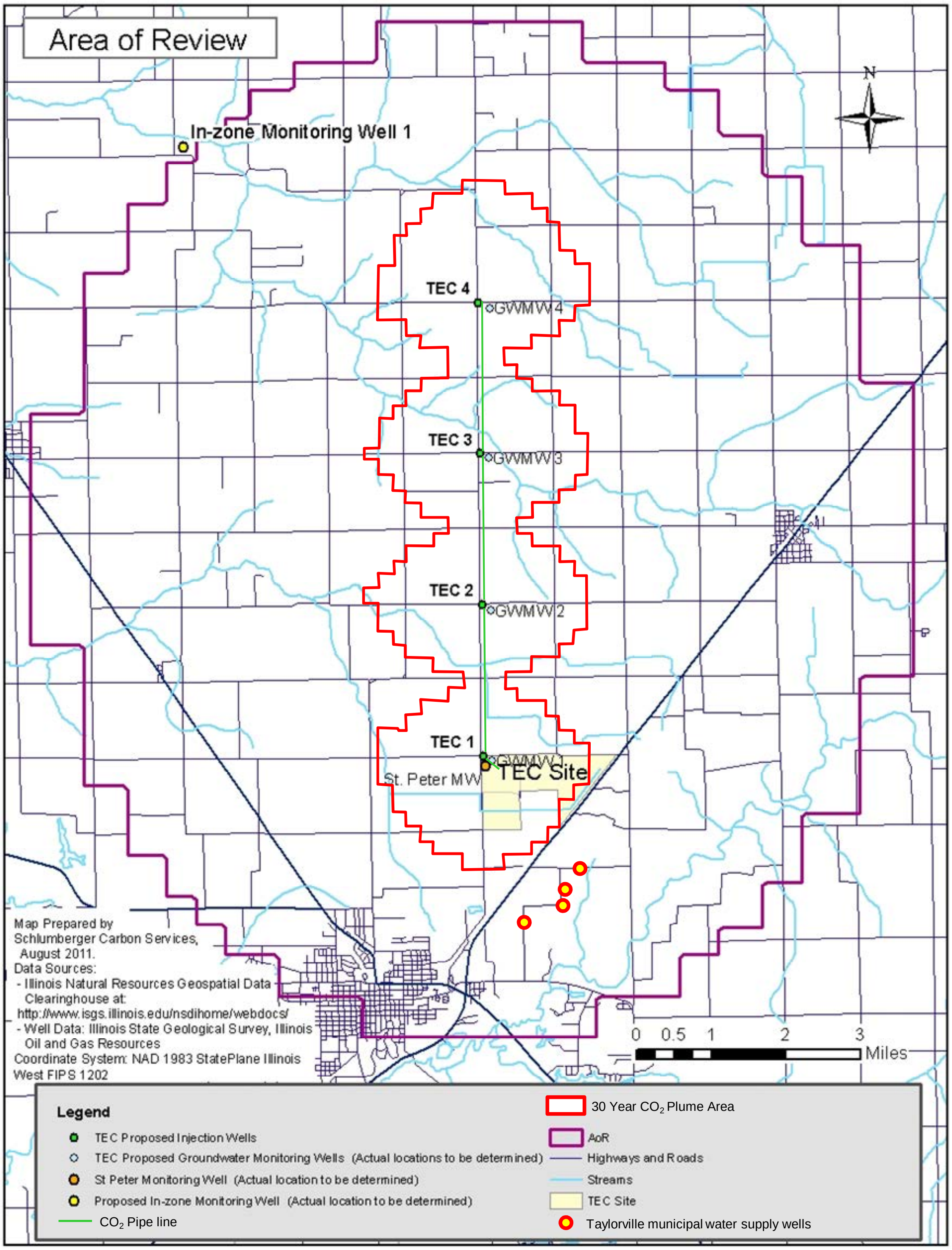
A detailed list of other contacts will be included in the final communications and remedial response plans.

Attachments:

1 Safety and Health Plan (To be prepared at a later date. See Discussion above in Section 4)

2 Map of AOR showing resources and infrastructure.

3 Summary Table: Examples of Potential Adverse Class VI Events and Emergency Response Options (from US EPA Class VI planning guidance)



Attachment 2 – Figure showing location of Taylorville well field.

Attachment 3 **Examples of Potential Adverse Class VI Events and Emergency Response Options**	
Leaking well Loss of mechanical integrity	• Stop injection. • Repair the well by plugging it with cement. • Pull and replace the tubing or the packer. • Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. • Install chemical sealant barrier to block leaks.
Well blowout	• Stop injection. • Close the blowout preventer; insert rams into the well. • Kill the well by pumping a fluid down the well bore that is heavier than the blowout fluid until the well stops flowing. • Drill another hole to intersect the well and pump fluid down.
Groundwater contamination	• Stop injection. • Pump carbon dioxide-contaminated groundwater to the surface and aerate it to remove carbon dioxide. • Apply "pump and treat" methods to remove trace elements. • Drill wells that intersect the accumulations in groundwater and extract carbon dioxide.
Surface water contamination	• Stop injection. • Shallow surface water bodies that have significant turnover (e.g. shallow lakes) or turbulence (e.g. streams) will quickly release dissolved carbon dioxide back into the atmosphere. • Create a hydraulic barrier by increasing reservoir pressure upstream of the leak.
Leakage through faults and fractures	• Stop injection. • Lower injection rates/pressures. • Install chemical sealant barriers to block leaks.
Accumulation of carbon dioxide in indoor air	• Stop injection. • Manage potential slow indoor releases with basement/substructure venting or pressurization. • Use fans to disperse carbon dioxide similar to radon fans.