9.0 Financial Responsibility

This chapter describes financial responsibilities related to the construction and operation of four horizontal wells for the injection of CO_2 in Morgan County, Illinois. The chapter first describes the Alliance's approach to demonstrating and maintaining financial responsibility for the construction, operation, closure, and monitoring of the proposed injection wells (Section 9.1). It then provides an overview of the cost of hiring a third party to perform corrective actions, if needed, on wells in the AoR after injection begins,[1] injection well plugging, post-injection site care and site closure, and emergency and remedial response actions if needed (Section 9.2). Section 9.3 describes the Alliance's proposed CO_2 Storage Trust Fund that will be available for corrective actions required after injection begins, injection well plugging, and post-injection site care, and site closure. Section 9.4 describes the Alliance's proposed third-party insurance policy that would be available for conducting any necessary emergency or remedial response actions. References are provided in Section 9.5.

9.1 Alliance Financial Requirements Compliance Approach

The Alliance plans to use a trust fund and third-party insurance to provide sufficient funding for actions that will or may need to be taken to protect USDWs within the AoR, which is defined in Chapter 3.0 of this supporting documentation. Together, these instruments will be sufficient to address endangerment of USDWs. Table 9.1 summarizes the approach the Alliance proposes to use to meet the financial responsibility requirements. Each of these instruments is described in full in subsequent sections of this chapter. Information related to the financial instruments will be updated on an annual basis and submitted to the U.S. EPA Director for review.

[1] With the exception of the FutureGen stratigraphic well, no wells located within the AoR extend to the confining zone (see Section 2.7.3). In fact, the closest penetration of the confining zone is approximately 16 mi (26 km) from the proposed injection wells (see Section 3.2.1). The modeling described in Chapter 3.0, Area of Review and Corrective Action Plan, shows that the projected CO_2 plume will not extend to this distance. Thus, there are no active or abandoned wells or underground mines that penetrate the confining zone in the AoR. For this reason, the Alliance does not expect to need to undertake any corrective actions before the start of CO_2 injection at the Morgan County CO_2 storage site or during the planned injection of up to 22 MMT over approximately 20 years. However, for purposes of the third-party cost estimate, the Alliance assumed that during the injection or post-injection period one previously unidentified well penetrating the confining zone would need to undergo corrective action to protect USDWs.

Table 9.1. Approach to Meeting Financial Responsibility Requirements

Required Activity	Qualifying Financial Instrument	Description
Corrective Actions (as necessary following periodic reevaluation of AoR)	CO_2 Storage Trust Fund	• Established pursuant to the U.S. Environmental Protection Agency (EPA) Geologic Sequestration (GS) Financial Responsibility regulation (40 CFR 146.85) • Created prior to injection • Held in trust by U.S. Bank National Association, as trustee
Injection Well Plugging	CO_2 Storage Trust Fund	• Same as above
Post-Injection Site Care and Site Closure	CO_2 Storage Trust Fund	• Same as above
Emergency and Remedial Response Actions	Third-Party Insurance	• Established pursuant to EPA GS Financial Responsibility regulation (40 CFR 146.85) • Pollution Legal Liability policy, with carbon capture and sequestration endorsement, placed prior to injection

9.2 Detailed Cost Estimate

To demonstrate that the financial instruments used by the Alliance will be sufficient to protect USDWs within the AoR, the Alliance asked Patrick Engineering, Inc., a nationwide engineering, design, and project management firm, to prepare a detailed estimate of the costs (in 2012 dollars) associated with corrective action on wells within the AoR after the start of injection, injection well plugging, post-injection site care, site closure, and emergency and remedial response actions that would or could be needed to protect USDWs. The cost estimate, which is contained in Appendix C, assumes that these costs would be incurred if the Alliance was no longer involved in the FutureGen 2.0 Project and a third party was asked to conclude the project. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, overhead, and profit.

The cost estimate is based upon historic price data from other projects managed by Patrick Engineering, Inc., cost quotes from third-party companies, EPA guidance documents, and professional judgment about the level of effort required to complete an activity. The estimated costs for each planned activity are listed in Table 9.2. Although the probability of such events occurring is extremely low, the types of events that could require emergency and remedial response actions and the cost of such actions are listed in Table 9.3. This information is consistent with Chapter 8.0, Emergency and Remedial Response Plan.

Table 9.2. FutureGen 2.0 Third-Party Cost Estimate for Planned Activities

Required Activity	Cost Estimate ($ millions)
AoR and Corrective Action	0.623
Injection & Monitoring Well Plugging (including site reclamation)	2.723
Post-Injection Site Care	18.32
Site Closure	3.402
Total	25.068

Table 9.3. FutureGen 2.0 Third-Party Cost Estimate for Emergency and Remedial Response Actions

Required Activity	Cost Estimate ($ millions)
1. Post-injection USDW contamination	
Acidification due to migration of CO_2	0.305
Toxic metal dissolution and mobilization	5.865
Displacement of groundwater with brine due to CO_2 injection	0.270
2. Post-injection failure scenarios (acute)	
Upward migration through CO_2 injection well	3.343
Upward migration through deep oil and gas wells	2.111
Upward migration through undocumented, abandoned, or poorly constructed wells	2.111
3. Post-injection failure scenarios (chronic)	
Upward migration as a result of the gradual failure of the confining zone(s)	5.865
Release through existing faults due to effects of increased pressure	5.865
Release through induced faults due to effects of increased pressure	6.10
Upward migration through CO_2 injection well	0.821
Upward migration through deep oil and gas wells	0.411
Upward migration through undocumented, abandoned, or poorly constructed deep wells	0.411
4. Other	
Catastrophic failure of confining zone(s)	6.10
Failure of confining zone(s) or well integrity due to seismic event	6.10

9.3 CO_2 Storage Trust Fund

This section describes the selection of a trustee for the CO_2 Storage Trust Fund, the Trust Agreement, and the financial strength of the trustee. The trust fund will be established prior to injection and will be designed to meet the requirements of 40 CFR 146.85.

The Alliance expects that DOE will share the cost of the initial funding of the trust in a manner similar to the cost-sharing for other project-related expenses. The initial funding level has not yet been determined. The trust fund will be available for corrective action on wells within the AoR after the start of injection and, after injection ceases, for injection well plugging, post-injection site care, and site closure. The trust funds will be available to the Alliance or to a third party if the Alliance were no longer involved in the FutureGen 2.0 Project.

9.3.1 Trustee Selection

On October 27, 2011, the Alliance sent requests to eight local, regional, and national banks seeking a statement of qualifications for the management of an irrevocable trust to meet the Alliance's obligations for injection well plugging and post-injection site care and site closure. The Alliance provided the trustee requirements and specifications that prospective trustees must meet and provided the draft Trust Agreement included in *Underground Injection Control (UIC) Program Class VI Financial Responsibility Guidance, Appendix B* (EPA 2011). Expressions of interest were due to the Alliance by November 15, 2011.

On December 19, 2011, the Alliance sent a formal Request for Proposal to the four banks that had expressed interest in serving as the trustee for the CO_2 Storage Trust Fund; clarifications were issued on January 10, 2012. On January 13, 2012, the four banks submitted their proposals.

Each proposal was reviewed and evaluated by a four-member review committee that assigned scores to price and non-price proposal responses. The price portion of the proposal was worth 33.3 percent of the total score and was based on five different categories such as setup fees, transaction fees, and other costs and fees. The non-price portion was worth 67.7 percent of the total score and was based on 14 different categories including the type, size, and location of assets held; the banks' ratings; and their experience working with federal agencies.

Based on the scoring summarized above, the review team unanimously recommended that the Alliance enter into negotiations with U.S. Bank as the prospective trustee in support of the financial assurance requirements associated with the UIC permit application.

9.3.2 Trust Agreement

U.S. Bank stated that it is able to accept a form of trust agreement that largely conforms to the Sample Trust Agreement provided by the Alliance, which includes the terms recommended by the EPA.

9.3.3 Financial Strength of the Trustee

U.S. Bank has been providing trust services for more than 100 years and currently administers more than 120,000 client matters in its Corporate Trust Division with $4 trillion in assets under its administration. U.S. Bank has trusts in Morgan County, Illinois, that have assets of between $200 million and $300 million. U.S. Bank has a credit rating in the top categories from all of Standard & Poor's or Moody's Investor Service and Fitch Ratings. Importantly, U.S. Bank serves as trustee on more than 200 environmental protection or remediation trusts, including trust estates of hundreds of millions of dollars. The bank is involved in environmental trusts involving multiple beneficiaries including EPA and state environmental protection agencies.

9.4 Third-Party Insurance

This section describes the manner in which the Alliance will select a third-party insurer, develop an insurance estimate, obtain proof of insurance, and confirm the financial strength of the insurer.

9.4.1 Selection of Third-Party Insurer

The Alliance has procured the services of McGriff, Siebels & Williams (McGriff), an insurance broker operating as a separate, wholly owned subsidiary of BB&T Insurance Services. As the largest independent energy broker in the United States, McGriff serves as the broker to electric generation, natural gas, water and wastewater treatment, and energy services companies, among others. McGriff developed and placed the first insurance policy for CCS liability, representing American Electric Power on the Mountaineer Project. The company is currently engaged with multiple CCS projects on their insurance program development and management.

McGriff prepared a memorandum for the Alliance that describes the applicable insurance products, expected policy terms and conditions, exclusions, and costs and deductibles. That memorandum and a specimen policy form with a sample CCS endorsement are contained in Appendix D. A summary of the information provided by McGriff is provided in the following sections.

9.4.2 Insurance Estimate and Application

The Alliance intends to secure third-party insurance to cover the potential need to undertake emergency and remedial response actions to protect USDWs in the AoR. Although the Alliance has been able to obtain information about the possible terms, conditions, and cost of such a policy, the Alliance has not yet applied for such a policy. This section describes the type of coverage that the Alliance expects to obtain from a third-party insurer, including protective conditions of coverage (cancellation, renewal, and continuation provisions). Additional information about deductions, exceptions, and the premium to be paid is also provided.

9.4.2.1 Type of Coverage

After surveying the insurance marketplace, it is McGriff's understanding and opinion that the purchase of a Pollution Legal Liability (PLL) policy will provide insurance coverage for cleanup costs if the Alliance were to become legally obligated to remediate contamination of USDWs. The Alliance expects to obtain a PLL insurance policy, which will include a specifically crafted endorsement designed to address the environmental risk exposures for CCS injection and storage operations. PLL insurance can generally be obtained for bodily injury, property damage, and remediation costs arising from pollution-related exposures and would include coverage for defense costs. PLL policies contain an aggregate limit of liability for the term of the policy. To protect other aspects of the Alliance's FutureGen 2.0 activities, a PLL policy would cover costs in excess of those needed to carry out any possible emergency and remedial response actions.

A PLL policy would cover the following identified events affecting a USDW and requiring emergency and remedial response actions:

- acidification due to migration of CO_2
- toxic metal dissolution and mobilization
- displacement of groundwater with brine due to CO_2 injection
- acute and chronic upward migration through the CO_2 injection well
- acute and chronic upward migration through deep oil and gas wells
- acute and chronic upward migration through undocumented, abandoned, or poorly constructed wells
- upward migration as a result of the gradual failure of the confining zone(s)
- release through existing or induced faults due to effects of increased pressure
- catastrophic failure of the confining zone(s)
- failure of the confining zone(s) or well integrity due to seismic events.

In order for the policy to respond to the events listed above, the action must fall within the definition of "cleanup costs" and be required by "environmental law." The specimen policy definition of "cleanup costs" is as follows:

Clean-Up Costs means reasonable and necessary expenses, including legal expenses incurred with the Company's written consent which consent shall not be unreasonably withheld or delayed, for the investigation, removal, treatment including in situ treatment, remediation including associated monitoring, or disposal of soil, surface water, groundwater, microbial matter, Legionella pneumophila, or other contamination:

1. *To the extent required by environmental laws or required to satisfy a Voluntary Cleanup Program;*
2. *With respect to Microbial Matter, in the absence of any applicable Environmental Laws, to the extent recommended in writing by a Certified Industrial Hygienist; or*
3. *With respect to Legionella pneumophila, in the absence of any applicable Environmental Laws, to the extent required in writing by the Center for Disease Control or local health department; or*
4. *That have been actually incurred by the government or any political subdivision of the U.S. or any state thereof or Canada or any province thereof, or by third parties.*

Clean-Up Costs also include Restoration Costs.

The specimen policy definition of "environmental law" is as follows:

Environmental Law means any federal, state, provincial or local laws (including, but not limited to, statutes, rules, regulations, ordinances, guidance documents, and governmental, judicial or administrative orders and directives) that are applicable to the pollution condition.

Other specific information regarding expected coverage is contained in the specimen policy form in Appendix D (Section I).

9.4.2.2 Coverage Limits

McGriff believes that the greatest exposure would be a catastrophic failure of the confining zone, which would have an estimated cost of $6.1 million for emergency and remedial response actions to protect USDWs (see Third-Party Cost Estimate in Appendix C). Because the actual claim amount could be much higher, McGriff recommends that the Alliance purchase $100 million in insurance coverage. The limits of liability are discussed in more detail in the specimen policy form in Appendix D (Section V).

9.4.2.3 Deductible

Based on its experience in placing other CCS policies, McGriff indicates that the deductible would be $250,000. The deductible is discussed in more detail in the specimen policy form in Appendix D (Section V(F)).

9.4.2.4 Exclusions

The common exclusions applicable to all coverages are contained in the specimen policy form in Appendix D (Section II).

9.4.2.5 Renewal

McGriff indicates that the insurance market currently offers PLL policy terms of 3 to 5 years, depending on the required limit of liability. The market, at this time, will not guarantee renewal of such a policy because market conditions at expiration, loss of reinsurance capacity, or risk appetite for CCS exposures may limit the ability of the insurers to offer renewal terms.

9.4.2.6 Cancellation

The terms under which the policy may be cancelled are contained in the specimen policy form in Appendix D (Section VI(G)). In general, the policy may be cancelled by the Alliance by surrender of the policy. It may be cancelled by the insurance company only for nonpayment of the premium, misrepresentation by the Alliance, failure of the Alliance to comply with material terms, or a change in use or operation.

9.4.2.7 Premium

McGriff estimates that a $100 million insurance policy with a deductible of $250,000 would cost between $625,000 and $825,000 annually. This is only an estimate; the premium will be determined based on information provided to the underwriter prior to a cost quotation.

9.4.3 Proof of Insurance

Proof of insurance will be provided when the insurance policy is obtained, prior to injection.

9.4.4 Financial Strength of Insurer

The financial strength of the insurer will be an important component of the Alliance's selection of an insurer. Information regarding the insurer's financial strength will be provided to the EPA when the insurer is selected.

9.5 References

40 CFR 146.85. Code of Federal Regulations, Title 40, *Protection of the Environment*, Part 146, "Underground Injection Control Program: Criteria and Standards," Section 85, "Financial responsibility."

Clean Coal FutureGen for Illinois Act. Illinois Public Act 097-0618, effective October 26, 2011

EPA (U.S. Environmental Protection Agency). 2011. *UIC Program Class VI Financial Responsibility Guidance*, Appendix B (Recommended Financial Responsibility Instruments). EPA 816-R-11-005, Washington, D.C.

Appendix A

Requirements Matrices

Appendix A

Requirements Matrices

The following tables specify where in this supporting documentation the applicable regulatory provisions in the Geologic Sequestration Rule are addressed. Table A.1 addresses the required information in 40 CFR 146.82(a), Table A.2 addresses the minimum criteria for siting in 40 CFR 146.83, and Table A.3 addresses the criteria and standards in 40 CFR 146.84 through 146.95.

Table A.1. Required Class VI Permit Information

40 CFR §146.82(a) - Required Class VI permit information		FutureGen Alliance UIC Permit Application
(a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to §146.91(e), and the Director shall consider the following:		
(1) Information required in §144.31 (e)(1) through (6) of this Section;	§144.31 (e)(1) - (6) Information Requirements	Section 1
	(1) The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination System (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	Section 1
	(2) Name, mailing address, and location of the facility for which the application is submitted.	Section 1, Table 1.2
	(3) Up to four SIC codes which best reflect the principal products or services provided by the facility.	Section 1, Table 1.2
	(4) The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	Section 1, Table 1.2
	(5) Whether the facility is located on Indian lands.	Section 1, Table 1.2
	(6) A listing of all permits or construction approvals received or applied for under any of the following programs:	
	(i) Hazardous Waste Management program under RCRA.	Section 1, Table 1.3
	(ii) UIC program under SDWA.	Section 1, Table 1.3
	(iii) NPDES program under CWA.	Section 1, Table 1.3
	(iv) Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	Section 1, Table 1.3
	(v) Nonattainment program under the Clean Air Act.	Section 1, Table 1.3
	(vi) National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.	Section 1, Table 1.3
	(vii) Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.	Section 1, Table 1.3
	(viii) Dredge and fill permits under section 404 of CWA	Section 1, Table 1.3
	(ix) Other relevant environmental permits, including State permits.	Section 1, Table 1.3

Table A.1. (contd)

40 CFR §146.82(a) - Required Class VI permit information	FutureGen Alliance UIC Permit Application
(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with §146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	Section 2, Figure 2.33
(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	Section 2
(i) Maps and cross sections of the area of review;	Section 2, various
(ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Section 2
(iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	Section 2
(iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Section 2.4
(v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Section 2.5
(vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Section 2
(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	Section 2.8
(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Section 2.6, 2.8
(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Section 2.2, Section 2.6
(7) Proposed operating data for the proposed geologic sequestration site:	Section 4
(i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	Section 4.1.3
(ii) Average and maximum injection pressure;	Section 4.2.1

Table A.1. (contd)

40 CFR §146.82(a) - Required Class VI permit information	FutureGen Alliance UIC Permit Application
(iii) The source(s) of the carbon dioxide stream; and	Section 4.1.1
(iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.	Section 4.1.2
(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at §146.87;	Section 4.3, 5.2.3.1
(9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	Section 4.4
(10) Proposed procedure to outline steps necessary to conduct injection operation;	Section 4.0
(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	Section 4.2.6
(12) Injection well construction procedures that meet the requirements of §146.86;	Section 4.2
(13) Proposed area of review and corrective action plan that meets the requirements under §146.84;	Section 3
(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under §146.85;	Section 9
(15) Proposed testing and monitoring plan required by §146.90;	Section 5
(16) Proposed injection well plugging plan required by §146.92(b);	Section 6
(17) Proposed post-injection site care and site closure plan required by §146.93(a);	Section 7
(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by §146.93(c);	The Alliance is not proposing an alternative timeframe at this time.
(19) Proposed emergency and remedial response plan required by §146.94(a);	Section 8
(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and	Section 8.5, Table 8.3, Table 8.4
(21) Any other information requested by the Director.	No additional information has been requested by the Director at this time.

Table A.2. Minimum Criteria for Siting

40 CFR §146.83 - Minimum Criteria for Siting	FutureGen Alliance UIC Permit Application
(a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	Section 2
(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Section 2.9
(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Section 2.9, Conclusion of 2Summary
(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	No additional requirements have been imposed at this time.

Table A.3. Criteria and Standards Applicable to Class VI Wells

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
§146.84 Area of review and corrective action.	
(a) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	Section 3.1.8
(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	
(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Section 3.0
(2) A description of:	
(i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	Section 3.1.9.1
(ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	Section 3.1.9.2
(iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	Section 3.1.9.2
(iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	Section 3.2.2
(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	
(1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	Section 3.0
(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	Section 3.1.3

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Section 3.1.3
(iii) Consider potential migration through faults, fractures, and artificial penetrations.	Section 3.2.1
(2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	Section 3.2.1
(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	Section 3.2.1
(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	Section 3.2
(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	
(1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	Section 3.1.9.1
(2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	Section 3.2.2
(3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	Section 3.2.2
(4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§144.39 or 144.41 of this Section, as appropriate.	Section 3.1.9.1
(f) The emergency and remedial response plan (as required by §146.94) and the demonstration of financial responsibility (as described by §146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	Section 3.1.9.3
(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	Section 3.1.9.3
§146.85 Financial responsibility.	
(a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	Section 9.0
(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments: (i) Trust Funds, (ii) Surety Bonds, (iii) Letter of Credit, (iv) Insurance, (v) Self Insurance (i.e., Financial Test and Corporate Guarantee), (vi) Escrow Account, (vii) Any other instrument(s) satisfactory to the Director	Section 9.1

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(2) The qualifying instrument(s) must be sufficient to cover the cost of:	
(i) Corrective action (that meets the requirements of §146.84);	Section 9.1, Table 9.1
(ii) Injection well plugging (that meets the requirements of §146.92);	Section 9.1, Table 9.1
(iii) Post injection site care and site closure (that meets the requirements of §146.93); and	Section 9.1, Table 9.1
(iv) Emergency and remedial response (that meets the requirements of §146.94).	Section 9.1, Table 9.1 Section 9.4.2
(3) The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	Section 9.2
(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.	
(i) Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	Appendix D
(A) Cancellation – for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice.	Section 9.4.2.6
(B) Renewal – for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	Section 9.4.2.5
(C) Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: the Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.	Section 9.5
(5) The qualifying financial responsibility instrument(s) must be approved by the Director.	
(i) The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§146.82).	
(ii) The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.	Section 9.1

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(iii) The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.	
(6) The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.	Section 9.1
(i) In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.	Section 9.1, Table 9.1
(ii) When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	Section 9.3.3
(iii) An owner or operator using certain types of third party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.	Section 9.3.2
(iv) An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.	Section 9.3
(v) An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: a ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; a ratio of current assets minus current liabilities to total assets greater than -0.1; and a net profit (revenues minus expenses) greater than 0.	Self-Insurance not invoked
(vi) An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.	Corporate guarantee not invoked.
(vii) An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.	Section 9.4

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit. (1) The owner or operator must maintain financial responsibility and resources until: (i) The Director receives and approves the completed post-injection site care and site closure plan; and (ii) The Director approves site closure. (2) The owner or operator may be released from a financial instrument in the following circumstances: (i) The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or (ii) The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.	
(c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response. (1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator. (2) During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§146.84), the injection well plugging plan (§146.92), the post-injection site care and site closure plan (§146.93), and the emergency and remedial response plan (§146.94). (3) The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§146.84), the injection well plugging plan (§146.92), the post-injection site care and site closure plan (§146.93), and the emergency and response plan (§146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section. (4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.	
(1) In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.	
(2) A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.	
(3) An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.	
(e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by §146.84), injection well plugging (as required by §146.92), post-injection site care and site closure (as required by §146.93), and emergency and remedial response (as required by §146.94).	
(f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	
§146.86 Injection well construction requirements.	
(a) General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	
(1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Section 4.2
(2) Permit the use of appropriate testing devices and workover tools; and	Section 4.2.4
(3) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	Section 4.2.4
(b) Casing and Cementing of Class VI Wells.	
(1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	Section 4.2.3
(i) Depth to the injection zone(s);	Table 4.12
(ii) Injection pressure, external pressure, internal pressure, and axial loading;	Section 4.2; 4.2.1

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(iii) Hole size;	Table 4.10
(iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	Tables 4.10, 4.11
(v) Corrosiveness of the carbon dioxide stream and formation fluids;	Table 5.1 (corrosion coupons)
(vi) Down-hole temperatures;	Section 4.3
(vii) Lithology of injection and confining zone(s);	Figures 4.4, 4.5
(viii) Type or grade of cement and cement additives; and	Table 4.12
(ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.	Section 4.1.3, 4.1.4, 4.2.1
(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Figures 4.4, 4.5
(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	Figures 4.4, 4.5
(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	Section 4.2.3
(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Section 4.2.3
(c) Tubing and packer.	
(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	Section 4.2.6
(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	Section 4.2
(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	
(i) Depth of setting;	Figures 4.4, 4.5
(ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Table 4.1

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(iii) Maximum proposed injection pressure;	Section 4.2.1
(iv) Maximum proposed annular pressure;	Section 4.2.5
(v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	Section 4.1.3
(vi) Size of tubing and casing; and	Table 4.10
(vii) Tubing tensile, burst, and collapse strengths.	Table 4.11
§146.87 Logging, sampling, and testing prior to injection well operation.	
(a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under §146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	Section 4.2.9
(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	Section 4.2.9
(2) Before and upon installation of the surface casing:	Section 4.2.10
(i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	Section 4.2.10
(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	Table 4.14
(3) Before and upon installation of the long string casing:	
(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	Table 4.14
(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.	Table 4.14
(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	
(i) A pressure test with liquid or gas;	Section 4.3
(ii) A tracer survey such as oxygen-activation logging;	Section 4.3
(iii) A temperature or noise log;	Section 4.3
(iv) A casing inspection log; and	Table 5.3
(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	Section 4.2.11
(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Section 4.2.11
(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	
(1) Fracture pressure;	Section 4.2.1
(2) Other physical and chemical characteristics of the injection and confining zone(s); and	Sections 2.1.3, 2.2
(3) Physical and chemical characteristics of the formation fluids in the injection zone(s).	Section 2.2
(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	
(1) A pressure fall-off test; and,	Section 5.3.1
(2) A pump test; or	Section 4.2.9
(3) Injectivity tests.	Section 4.2.9
(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	Section 4.8.7
§146.88 Injection well operating requirements.	
(a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	Section 4.2.1
(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Section 4.2.5
(c) 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.	Section 4.2.5
(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	Section 4.2.6

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(e) The owner or operator must install and use:	
(1) Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	Table 5.3
(2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and	Section 5.3.4
(3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	Not Applicable
(f) If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:	
(1) Immediately cease injection;	Section 8.1.3
(2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;	Table 8.2
(3) Notify the Director within 24 hours;	Section 8.5
(4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	Section 8.2
(5) Notify the Director when injection can be expected to resume.	Section 8.2
§146.89 Mechanical Integrity.	
(a) A Class VI well has mechanical integrity if:	
(1) There is no significant leak in the casing, tubing, or packer; and	
(2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	
(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Section 4.3
(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	Table 5.3
(1) An approved tracer survey such as an oxygen-activation log; or	Table 5.3
(2) A temperature or noise log.	Table 5.3

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long string casing.	Table 5.1
(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	Section 5.7
(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	Section 5.7
(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	Section 5.7
§146.90 Testing and monitoring requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	Section 5.0
(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Table 5.3
(b) Installation and use, except during well workovers as defined in §146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Table 5.1
(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in §146.86(b), by:	Table 5.1
(1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	Table 5.1
(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	Not applicable
(3) Using an alternative method approved by the Director;	Not Applicable
(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	Section 5.2.2.2

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and	Section 5.1.4
(2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under §146.82(a)(6) and on any modeling results in the area of review evaluation required by §146.84(c).	Table 5.3, Figure 5.1
(e) A demonstration of external mechanical integrity pursuant to §146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at §146.89(d) at a frequency established in the testing and monitoring plan;	Table 5.3
(f) A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	Table 5.3
(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Section 5.2
(1) Direct methods in the injection zone(s); and,	Table 5.3
(2) Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Table 5.3
(h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	Section 5.2.1.3
(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under §146.84(c) and to determine compliance with standards under §144.12 of this Section;	
(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under §146.88, and the most recent area of review reevaluation performed under §146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§144.39 or 144.41 of this Section, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	Section 5.7
(1) Within one year of an area of review reevaluation;	
(2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	
(3) When required by the Director.	
(k) A quality assurance and surveillance plan for all testing and monitoring requirements.	Section 5.8
§149.91 Reporting Requirements. The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	Section 5.6

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(a) Semi-annual reports containing:	Section 5.6
(1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	
(2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	
(3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	
(4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	
(5) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	
(6) Monthly annulus fluid volume added; and	
(7) The results of monitoring prescribed under § 146.90.	
(b) Report, within 30 days, the results of:	Section 5.6
(1) Periodic tests of mechanical integrity;	
(2) Any well workover; and,	
(3) Any other test of the injection well conducted by the permittee if required by the Director.	
(c) Report, within 24 hours:	Section 5.6
(1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	
(2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	
(3) Any triggering of a shut-off system (i.e., down-hole or at the surface);	
(4) Any failure to maintain mechanical integrity; or.	
(5) Pursuant to compliance with the requirement at ¤ 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.	
(d) Owners or operators must notify the Director in writing 30 days in advance of:	Section 5.6
(1) Any planned well workover;	
(2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and	
(3) Any other planned test of the injection well conducted by the permittee.	
(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	Section 5.6

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(f) Records shall be retained by the owner or operator as follows:	
(1) All data collected under ¤ 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	Section 5.6
(2) Data on the nature and composition of all injected fluids collected pursuant to ¤ 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.	Section 5.6
(3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	Section 5.6
(4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at ¤¤ 146.93(f) and (h) shall be retained for 10 years following site closure.	Section 5.6, Section 7.3.4
(5) The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	
§146.92 Injection well plugging.	Section 6.0
(a) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Sections 6.1, 6.2
(b) *Well Plugging Plan.* The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	Section 6.3
(1) Appropriate tests or measures for determining bottomhole reservoir pressure;	Section 6.1.1
(2) Appropriate testing methods to ensure external mechanical integrity as specified in §146.89;	Section 6.2
(3) The type and number of plugs to be used;	Section 6.3
(4) The placement of each plug, including the elevation of the top and bottom of each plug;	Table 6.1
(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	Table 6.1
(6) The method of placement of the plugs.	Section 6.3
(c) Notice of intent to plug.	Section 6.3
(d) Plugging report.	Section 6.3
§146.93 Post-injection site care and site closure.	Section 7.0
(a) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director.	Section 7.0

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	Section 7.0
(2) The post-injection site care and site closure plan must include the following information:	
(i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	Table 7.1, Section 7.1.1
(ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under §146.84(c)(1);	Figure 7.2
(iii) A description of post-injection monitoring location, methods, and proposed frequency;	Section 7.2
(iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to §146.91(e); and,	Section 7.2.4, Table 7.2.4
(v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	Section 7.2
(b) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	Section 7.2
(1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	Section 7.2
(2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	
(3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	Section 7.2.6
(4) If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(c) *Demonstration of alternative post-injection site care timeframe*. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.	A default period is not being proposed at this time.
(1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	
(i) The results of computational modeling performed pursuant to delineation of the area of review under §146.84;	
(ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	
(iii) The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	
(iv) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	
(v) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	
(vi) The results of laboratory analyses, research studies, and/or field or site specific studies to verify the information required in paragraphs (iv) and (v) of this section;	
(vii) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	
(viii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	
(ix) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	
(x) The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	
(xi) Any additional site-specific factors required by the Director.	
(2) Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	
(i) All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	
(ii) Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(iii) Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	
(iv) Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	
(v) Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	
(vi) An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	
(vii) An approved quality assurance and quality control plan must address all aspects of the demonstration; and,	
(viii) Any additional criteria required by the Director.	
§146.94 Emergency and remedial response.	Section 8.0
(a) As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Section 8.0
(b) If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	Section 8.1, Table 8.2
(1) Immediately cease injection;	Table 8.2
(2) Take all steps reasonably necessary to identify and characterize any release;	Table 8.2
(3) Notify the Director within 24 hours; and	Section 8.5
(4) Implement the emergency and remedial response plan approved by the Director.	Section 8.0
(c) The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	
(d) The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this Section, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	Section 8.3

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(1) Within one year of an area of review evaluation;	Section 8.3
(2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	Section 8.3
(3) When required by the Director.	Section 8.3
§146.95 Class VI injection depth waiver requirements.	No waiver is requested.

Appendix B

Known Wells Within the Survey Area

Appendix B

Known Wells Within the Survey Area

Table B.1. List of Wells Located Within the Survey Area and Outside the AoR

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
2	121372155200	237387	39.815638	-90.084967	T16N,R9W,Sec 23	41		19920313	Nickel, Gerald	1	Water	Private Water Well	No
3	121372182100	300966	39.815638	-90.084967	T16N,R9W,Sec 23	46		19971104	Nickel, Gerald & Diane	1	Water	Private Water Well	No
13	121372173400	297871	39.811987	-90.07805	T16N,R9W,Sec 26	37		19960213	Keltner, Dale		Water	Private Water Well	No
23	121370024000		39.780186	-90.094859	T15N,R9W,Sec 3	402	642	19230101	Trotter, L.B.	1	Oil & Gas	Dry and Abandoned, No Shows	No
24	121372097800		39.776078	-90.080727	T15N,R9W,Sec 3	327	632	0	Harris		Unknown / other	Unknown, Plugged	No
28		115642	39.82166	-90.041238	T16N,R8W,Sec 19	25		1870	W W Robertson		Water		No
38		116456	39.776761	-90.107843	T15N,R9W,Sec 4	30			Rayburn		Water		No
39		116457	39.776761	-90.107843	T15N,R9W,Sec 4	32			Greene		Water		No
40		115725	39.821959	-90.097446	T16N,R9W,Sec 22	18			K Brown		Water		No
41		115726	39.821959	-90.097446	T16N,R9W,Sec 22	30			E C Trotter		Water		No
52		115640	39.836203	-90.022343	T16N,R8W,Sec 17	25			J H Hubbs		Water		No
53		115641	39.83617	-90.041154	T16N,R8W,Sec 18	32		1850	H Robinson		Water		No
54		115643	39.821671	-90.022214	T16N,R8W,Sec 20	26		1900	S Weinfeldt		Water		No
55		115644	39.821671	-90.022214	T16N,R8W,Sec 20	30		1904	Robinson		Water		No
56		115649	39.807149	-90.022402	T16N,R8W,Sec 29	26			M Walbaum		Water		No
57		115653	39.793	-90.022	T16N,R8W,Sec 32	18			Beggs		Water		No
58	121372070800	116522	39.77156	-90.0878	T15N,R9W,Sec 3	50		19770320	Lineberger, David		Water		No
59	121372118300	116520	39.769673	-90.080523	T15N,R9W,Sec 3	42			Harris, Frank R.		Water	Private Water Well	No
60	121372070700	116521	39.769673	-90.080523	T15N,R9W,Sec 3	40			harris F R		Water		No
61		116458	39.777	-90.126	T15N,R9W,Sec 5	30			Gary S. B.		Water		No
62		116464	39.761	-90.126	T15N,R9W,Sec 8	30			Clemy W		Water		No
63		116465	39.761	-90.126	T15N,R9W,Sec 8	40			Coons A		Water		No
64		116466	39.761	-90.107	T15N,R9W,Sec 9	30			Wallbaum W M		Water		No
65		116467	39.761	-90.107	T15N,R9W,Sec 9	35			Trotter I B		Water		No
66		227314	39.761	-90.107	T15N,R9W,Sec 9	40			Carl Shinnall #1		Water		No
67		116468	39.761	-90.089	T15N,R9W,Sec 10	30			Orear R		Water		No
68	121372070900	116525	39.765755	-90.080645	T15N,R9W,Sec 10	40			Lineburger D		Water		No
69		116469	39.761	-90.07	T15N,R9W,Sec 11	30			Collins W		Water		No
70		116470	39.761	-90.07	T15N,R9W,Sec 11	32			Lockhart G		Water		No
71		116393	39.776799	-90.032936	T15N,R8W,Sec 6	25		1923			Water		No
72		116394	39.776799	-90.032936	T15N,R8W,Sec 6	28			C Smith		Water		No
73	121372116800	116436	39.784526	-90.041604	T15N,R8W,Sec 6	54		19770226	Becker, Carl J.	1	Water	Livestock Watering Well	No
74	121372116900	116435	39.784526	-90.041604	T15N,R8W,Sec 6	43		19781010	Becker, Carl J.	1	Water	Private Water Well	No
75	121372117000	116434	39.782453	-90.041567	T15N,R8W,Sec 6	27		19761213	Smith, Lloyd E.	1	Water	Livestock Watering Well	No
76	121372161900		39.766277	-90.041266	T15N,R8W,Sec 7	26			Walpole, Ron		Water		No
77		116395	39.763	-90.033	T15N,R8W,Sec 7	30					Water		No
78		115696	39.836221	-90.059875	T16N,R9W,Sec 13	25			V R Mc Clure		Water		No

Table B.1. (contd)

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
79		115697	39.836221	-90.059875	T16N,R9W,Sec 13	27			U B Fox		Water		No
80		115698	39.836221	-90.059875	T16N,R9W,Sec 13	27			G W Lewis		Water		No
81		115699	39.836362	-90.078662	T16N,R9W,Sec 14	30			J Parrat		Water		No
82		115700	39.836362	-90.078662	T16N,R9W,Sec 14	28			C W Lewis		Water		No
83		115701	39.836362	-90.078662	T16N,R9W,Sec 14	28			J W Parrat		Water		No
84		115702	39.836362	-90.078662	T16N,R9W,Sec 14	32			J Hodgeson		Water		No
85	121372203900	356742	39.830101	-90.102984	T16N,R9W,Sec 15	47		20030910	Lomar Hager Construction		Water	Private Water Well	No
86		115703	39.836486	-90.097369	T16N,R9W,Sec 15	24			G Noulty		Water		No
87		115704	39.836486	-90.097369	T16N,R9W,Sec 15	30			L Lamkaular		Water		No
88		115705	39.836486	-90.097369	T16N,R9W,Sec 15	35			E E Hart		Water		No
89		115706	39.8365	-90.116151	T16N,R9W,Sec 16	23			S Jumper		Water		No
90		115707	39.8365	-90.116151	T16N,R9W,Sec 16	25			H Wester		Water		No
91		115722	39.821967	-90.116263	T16N,R9W,Sec 21	30			T J Ward		Water		No
92		115724	39.821967	-90.116263	T16N,R9W,Sec 21	30			C Trotter		Water		No
93		216249	39.821967	-90.116263	T16N,R9W,Sec 21	28		1934	Wm Noulty		Water		No
94	121370028400		39.822767	-90.073164	T16N,R9W,Sec 23	405		19540301	Kellner	1	Water		No
95	121372155100	237377	39.820978	-90.077895	T16N,R9W,Sec 23	42		19920414	Allen, John D.	1	Water	Private Water Well	No
96	121372207600	365042	39.822764	-90.075515	T16N,R9W,Sec 23	46		20040715	Burton, Larry		Water	Private Water Well	No
97	121372128400	115776	39.826288	-90.058992	T16N,R9W,Sec 24	40		19760220	Robinson, Leroy A.	1	Water	Private Water Well	No
98	121372128500	115777	39.828869	-90.059535	T16N,R9W,Sec 24	37		19781214	Romine, Buddy	1	Water	Private Water Well	No
99	121372211600	420169	39.813876	-90.103667	T16N,R9W,Sec 27	35		20060809	Donnan, Jeff		Water	Private Water Well	No
100		115744	39.807541	-90.116512	T16N,R9W,Sec 28	110			Noah B Fox		Water		No
101		115745	39.807541	-90.116512	T16N,R9W,Sec 28	28			Noah B Fox		Water		No
102		115746	39.807541	-90.116512	T16N,R9W,Sec 28	30			C Holdbrook		Water		No
103		115723	39.807541	-90.116512	T16N,R9W,Sec 28	28			W Noulty		Water		No
104	121372203000	348692	39.806645	-90.122622	T16N,R9W,Sec 28	42			Kendra Swain		Water		No
105		115759	39.792956	-90.116724	T16N,R9W,Sec 33	30			H Swain		Water		No
106		115760	39.792956	-90.116724	T16N,R9W,Sec 33	28			L L Hart		Water		No
107	121372155000		39.822856	-90.119949	T16N,R9W,Sec 21				Spradlin, Jack		Water		No
108	121370011400		39.833775	-90.10777	T16N,R9W,Sec 16	385	616	19551101	Wolfe, Eliz	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
109	121370011500		39.80091	-90.040421	T16N,R8W,Sec 30	420	635	19560101	Beilschmidt	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
110	121370011600		39.815108	-90.028322	T16N,R8W,Sec 20	365	610	19551201	Robinson, Howard	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
111	121370018900		39.825408	-90.062536	T16N,R9W,Sec 24	200		19440101	Lewis, E. C.		Oil & Gas	Dry Hole	No
112	121370024100		39.769077	-90.111454	T15N,R9W,Sec 4	580			Rayborn	1	Oil & Gas	Gas Producer	No
113	121370044200		39.770193	-90.110273	T15N,R9W,Sec 4	350			Rayburn	1	Oil & Gas	Gas Producer	No
114	121372086900		39.769679	-90.098565	T15N,R9W,Sec 4	301					Coal Test		No
115	121370024200		39.778927	-90.119618	T15N,R9W,Sec 5	423			Green, Laura & Effie	1	Oil & Gas	Gas Producer	No
116	121370024600		39.764523	-90.098492	T15N,R9W,Sec 9	293			Baxter	2	Oil & Gas	Dry and Abandoned, Gas Shows	No
117	121372094800		39.767065	-90.11144	T15N,R9W,Sec 9	325			Beilschmidt	1	Oil&Gas	Temporarily Abandoned	No
118	121372105200		39.763524	-90.104346	T15N,R9W,Sec 9				Leinberger	2	Oil&Gas	Permit to Drill Issued	No
119	121370007900		39.766464	-90.091366	T15N,R9W,Sec 10	295			Dunlap	8	Oil & Gas	Gas Producer	No
120	121372084800		39.766422	-90.065678	T15N,R9W,Sec 11	243					Coal Test		No
121	121370030900		39.806625	-90.105838	T16N,R9W,Sec 27	324	610	19591001	Fox, Lyman	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
122	121370033200		39.788212	-90.03349	T16N,R8W,Sec 31	523	641	19271001	Corrington	1	Oil & Gas	Dry and Abandoned, No Shows	No

Table B.1. (contd)

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
123	121370062300		39.828772	-90.06935	T16N,R9W,Sec 24	814	624	19700701	#MA-3		Stratigraphic or Structure Test	Structure Test, Plugged	No
124	121372068000		39.792709	-90.039363	T16N,R8W,Sec 31	142	641	19700518	Flynn, Robert		Coal Test		No
125	121372088400		39.829096	-90.098826	T16N,R9W,Sec 22	318	621	0			Coal Test		No
126	121372088600		39.801122	-90.108499	T16N,R9W,Sec 28	301	621	0			Coal Test		No
127	121372067800		39.814431	-90.023514	T16N,R8W,Sec 20	130	610	19700507	Newberry, Lucille		Coal Test		No
128	121372086000		39.83138	-90.055009	T16N,R9W,Sec 13	301	619	0			Coal Test		No

Appendix C

Cost Estimate to Demonstrate Financial Responsibility for Class VI UIC Permit