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Subject: Comments on Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Proposed Rule; Docket ID No. EPA–HQ–OW–2008–0390 (73 Fed. Reg. 43492 (July 25, 2008))

To Whom It May Concern:

The Texas Carbon Capture and Storage Association (TxCCSA) is pleased to offer these perspectives on the United States Environmental Protection Agency's (EPA) proposed Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (hereinafter "Proposed Rule" or "NOPR").

TxCCSA Perspectives on the EPA's Proposed Rule for Geologic Sequestration

While the EPA's Proposed Rule represents a significant step in the development of Carbon Capture and Storage (CCS) as an emissions reduction strategy, the Proposed Rule assumes that sequestration or geologic storage[1] is defined as injection without simultaneous extraction of hydrocarbons, as in the case of enhanced oil recovery (EOR) or enhanced gas recovery (EGR) (e.g., enhanced coal bed methane or ECBM). The Proposed Rule focuses on sequestration outside the context of commercial product

[1] While the term sequestration and storage may be used interchangeably, we prefer the term "storage," as it contemplates recovery of injected CO_2 for beneficial use.

extraction and effectively separates CO_2 injection into two classes: sequestration in saline or other non-hydrocarbon related target formations and hydrocarbon related sequestration. In general, this focus reveals several concerns reflected in the Proposed Rule that the TxCCSA hopes to address, including: 1) the lack of clarification of the injectate stream which could lead to the stream being considered a waste; 2) the absence of a system for qualifying storage sites; 3) a lack of understanding of the number of wellbores required for scaled operations; 4) the attribution of harmful characteristics to the concept of buoyancy; 5) the lack of consideration for simultaneous storage and hydrocarbon production; 6) the post-injection site care timeframe; and 7) multi-state jurisdictional issues.

Point #1: The lack of clarification of the CO_2 injectate stream which could lead to the stream being considered a waste. We recognize and salute EPA's attempt to avoid labeling CO_2 injection as waste injection. Nevertheless, by tracking closely the Class I rules for the injection of hazardous waste (see Attachment A), the Proposed Rule appears to treat CO_2 as a waste. It will be difficult for geologic storage to move forward on this basis.

Also, in choosing not to state a composition specification minimum for CO_2, the EPA opens the door to having the CO_2 injectate stream declared a waste. We feel that is a serious weakness, compelling a regulatory approach for a worst-case injectate composition stream, and providing a basis for additional regulation under the Resources Conservation and Recovery Act (RCRA) or the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). The failure to define the composition specification minimum for CO_2 contributes to the overly protective approach of the EPA to the geologic storage of CO_2. The EPA should address this concern by specifically excluding injected supercritical CO_2 for geologic storage from regulation under both RCRA and CERCLA similar to what has been done for wastes associated with the exploration, development and production of crude oil, natural gas and geothermal energy under RCRA.[2]

Point #2: The absence of a system for qualifying geologic storage sites. Fundamentally, the TxCCSA believes that hydrocarbon related geologic storage is one of the important avenues by which the next generation of energy production will move forward. CO_2 occurs naturally in the subsurface and is no stranger to geologists who attempt to understand fluid migration and subsurface accumulations. The fact that CO_2 can be trapped in subsurface formations for geologic times is known and accepted; and more of these locations will undoubtedly be found. This brings us to another concern with the Proposed Rule

[2] *See* Regulatory Determination for Oil and Gas and Geothermal Exploration, Development, and Production Wastes; Regulatory Determination, 53 Fed. Reg. 25445 (July 6, 1988)

involving the absence of a system to qualify sites for CO_2 injection (i.e. a site permitting framework). We feel this it is necessary to rate sites for injection security. There is an evolving framework[3] which could form the basis for qualifying or rating sites. We believe that such a framework is necessary for the insurance industry that will oversee injection in non-hydrocarbon related geologic storage applications.

As currently written, EPA creates a separate Class VI category of UIC regulation for CO_2 storage in their attempt to avoid the Class I waste moniker. Where CO_2 storage sites can meet the qualifications for permitting, the TxCCSA believes that geologic storage is substantially similar to EOR/EGR and in those instances any regulations for Class VI wells should reflect more closely UIC Class II standards instead of the more stringent Class I hazardous waste well standards. If the geologic storage site doesn't qualify or if the injectate composition is such that it is truly a waste stream, then the well requirements should more directly reflect the requirements of Class I UIC standards, as with the proposed Class VI well category.

Point #3: The draft rules focus on minimizing the number of wellbore penetrations at a geologic storage facility. The Preamble discusses "numerous artificial penetrations" related to oil and gas reservoirs.[4] The TxCCSA believes this focus is misplaced and damaging because it potentially eliminates certain target geologic formations and represents an unrealistic approach to geologic storage.

In the first case, the best target geologic formations, typically producing or depleted oil and gas reservoirs, where geologic storage projects will be of dramatically lower risk, have numerous wellbore penetrations from previous exploration activity. Many of those formations have proven trapping conditions for substances lighter than brine and therefore very much like CO_2. In addition, the previous exploration activity provides the understanding of the subsurface to guide geologic storage projects. To eliminate those areas based upon a postulated concern of leakage from preexisting wellbores is misplaced. From a geologic perspective, it is much easier to fix a leaky wellbore than a leaky fault.

In the second case, this focus demonstrates a lack of understanding of the compartmentalization of natural reservoir systems. It will be inconceivable to expect a single well or even a single digit set of wells to accomplish geologic storage on a project of important size. An array of injection wells will be an imperative. Also, in the Cost Analysis section of the Preamble, the suggested use of three monitoring

[3] See the work of Dr. Steven Bryant, director of the Geologic CO2 Storage Joint Industry Project in the Center of Petroleum and Geosystems Engineering at the University of Texas.
[4] *See* 73 Fed. Reg. at 43503.

wells per injection well[5] displays a theoretical approach and a lack of practical understanding in how geologic storage projects would be implemented.

Point #4: The use of the term "CO_2 buoyancy," enumerated countless times in the draft rules, is misleading. The Preamble to the Proposed Rule makes very clear that changes to the UIC program for CO_2 geologic storage are based among other things on the assertion that CO_2 is "buoyant". This is simply incorrect. CO_2 is a non-explosive, non-flammable, non-toxic gas that possesses different physical properties than some other injectates or existing formation fluids. These physical properties do not include any special buoyancy characteristics or properties. Rather, CO_2 is simply more dense than some underground fluids or gases and less dense than others. Hence the movement of injected CO_2 in a reservoir, or any type of system containing different fluids or gases, will vary based on the relative densities of the various formation fluids or gases that are in the reservoir. The various formation fluids will simply segregate based on the relative densities of the fluids or gases, including CO_2. As a result, CO_2 may be the fluid that sinks to the bottom, rises to the top, or resides somewhere in between the top and the bottom within the reservoir system.

Point #5: The lack of consideration for simultaneous storage and hydrocarbon production. Another concern raised by the proposed EPA rule involves the lack of consideration for storage of CO_2 during oil and gas production. At TxCCSA, we strongly believe that the early CO_2 captured from industry sources will be injected in substantial volumes and stored during existing and new EOR operations. If the capturing company receives no value ("offset") for reducing emissions, the capture project will not proceed.

The only reference to the use of EOR sites for storage is contained in proposed rule § 146.83(c) which discusses how existing wells, particularly Class II wells used for EOR, can be carried over or re-permitted as Class VI wells The EPA should give greater emphasis to the commercial significance of CO_2-driven EOR under the existing Class II well permitting framework. Given the 36+ years of experience with CO_2 floods in the Permian Basin of West Texas, EOR will serve as a bridge to full-scale deployment of geologic storage by facilitating infrastructure development. Currently, 3500 miles of pipeline infrastructure exist to transport CO_2,and CO_2-driven EOR's demand for more CO_2 is poised to increase that number. Furthermore, some estimate that over 8 trillion cubic feet of CO_2 has been stored in the Permian Basin alone. These significant volumes represent an already mature industry that should be encouraged to expand.

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[5] *Id* at 43524.

The EPA should demonstrate a greater recognition of CO_2-driven EOR and simultaneously protect underground sources of drinking water by restructuring the Proposed Rule, reserving the new Class VI for use in permitting wells in certain non-hydrocarbon producing target formations and providing a mechanism that recognizes owners and operators seeking to engage in hydrocarbon related geologic storage under Class II well permits. This mechanism could take the form of a Class II subclass that would overlay Class II permit requirements with additional area of review, monitoring, reporting, post-injection site care and closure requirements. Such a regulatory regime would also recognize the differences between non-hydrocarbon related target formations and both depleted and producing oil & gas reservoirs.

Point #6*: *The proposed Post-injection Site Care period is too long based on prevailing science and risk profiles. The proposed rule establishes a default 50-year timeframe for the length of the post-injection site care period. TxCCSA strongly objects to the use of a 50-year timeframe for post-injection site care. Our objection stems from the relative risks associated with the various phases of geologic storage operations, the function of various geologic trapping mechanisms, the creation of artificial impediments to financial assurance and the sagacity of other regulatory proposals.

First, we believe as the literature suggests that a 50-year timeframe for post-injection site care is too long and wholly unrelated to the risks associated with geologic storage. For well-sited, characterized, operated and managed sites, the risks accumulate during the operational phase, and decline as sites move from post-injection site care to closure to eventual long-term care. Therefore, prevailing scientific opinion expects the risk profile to diminish with time.[6] As Patton and Trabucchi suggest "the likelihood that the risk of some events occurring that result in an unexpected release of carbon dioxide more than 10 years after termination of injection will become increasingly remote due to geochemistry conditions."[7] The geochemistry conditions they reference include the four main mechanisms which trap CO_2 in well-chosen geological formations – 1) *structural trapping* - which is addressed in the proposed rule and is not

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[6] *See* Intergovernmental Panel on Climate Change, *Special Report on Carbon Dioxide Capture and Storage*, 208 (Bert, Metz, et al. eds., 2005); *see also* Sally M. Benson, *Carbon Dioxide Capture and Storage: Research Pathways, Progress and Potential*, Global Climate & Energy Project Annual Symposium, October 2007, *available at*
http://pangea.stanford.edu/research/bensonlab/presentations/Carbon%20Dioxide%20Capture%20and%20Storage%20-%20Research%20Pathways%20Progress%20and%20Potential.pdf.

[7] Chiara Trabucchi and Lindene Patton, *Storing Carbon: Options for Liability Risk Management, Financial Responsibility*, Daily Environment Report, Bureau of National Affairs, pg. 8 (Sept. 3, 2008).

necessary to discuss further here; 2) *residual trapping* – where CO_2 is trapped by capillary forces in the interstices of the rock formation which develops about 10 years after injection; 3) *dissolution or solubility trapping* – where the CO_2 dissolves into the brine found in the geological formation and sinks because the CO_2 saturated brine is heavier than non-CO_2 saturated brine, taking place between 10 and 100 years after injection; and 4) finally *mineralization or mineral trapping* – which happens when dissolved CO_2 chemically reacts with the formation rock to produce minerals, a process requiring hundreds of years.[8]

Given that the greatest risk occurs during the operational stage of a geologic storage project and that residual and dissolution trapping start well in advance of 50 years, it is difficult to understand why a 50-year timeframe for post-injection site care was chosen. A 50-year post-injection site care timeframe is simply unrelated to the relative risks associated with geological storage and the function of geologic trapping mechanisms that limit the risk of unexpected release of CO_2 after the termination of injection activity.

Furthermore, other respected models suggest a much shorter period. For instance, the IOGCC Model Rules and Legislation stipulate a 10-29 year post-injection site care period.[9] Under the IOGCC Model, the operator of the storage site is the responsible party and is required to maintain an operational bond during the equivalent of a post-injection site care period and until closure. This 10-29 year post-injection site care period more easily relates to the relative risks of geologic storage and the geochemical reactions discussed above. Also, in the Preamble, EPA acknowledges that a 30-year post-closure care period is recognized as the industry standard for the injection of hazardous waste.[10]

Finally, when mapped to the requirement for financial assurance, this 50-year timeframe requirement raises barriers to obtaining financial assurance for prospective projects. Section 146.85 of the Proposed Rule requires the owner or operator to maintain financial responsibility for corrective action, injection well plugging, post-injection site care and site closure. Undoubtedly owners/operators will enter the private sector financial assurance market for some period in order to meet this requirement. Both an uncertain or 50-year post-injection site care timeframe create impediments to financial responsibility. We believe that an uncertain or exceedingly long post-injection site-care period will discourage the development of private sector products to address financial responsibility and discourage geologic storage in general.

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[8] *See* IPCC 2005 Report, supra, at 208; *see also* Benson

[9] *See* Task Force on Carbon Capture and Geologic Storage, The Interstate Oil and Gas Compact Commission, *Storage of Carbon Dioxide in Geologic Structures : A Legal and Regulatory Guide for States and Provinces* (Sept. 25, 2007) *available at* http://iogcc.myshopify.com/collections/frontpage/products/co2-storage-a-legal-and-regulatory-guide-for-states-2008.

[10] See 73 Fed. Reg. at 43510.

Given the limited risk profile of the post-operational phase of geologic storage, the impediments to financial responsibility and insurance caused by an uncertain or exceedingly lengthy post-injection site care period and the precedent set by other proposals, we think that a 50-year post-injection site care period is unsupported by the science, unnecessary to protect USDWs and unwarranted by current EOR experience.

Point #7: Multi-state jurisdictional issues. Finally, the scale of geologic storage projects could raise multi-state jurisdictional issues if the CO_2 plume and AoR extend beyond and across state boundaries. The proposed rule should speak to potential multi-state jurisdictional issues in a manner that avoids conflicting state requirements. For instance, one option would allow the well head or injection site location to control jurisdiction. This would provide a framework for addressing multi-state jurisdiction and give owners/operators some certainty regarding the approach to this issue.

We have attached specific detailed comments on the proposed regulatory text (Attachment B). Many of these comments were developed from the input of Association members with extensive experience in CO_2-driven EOR.

The TxCCSA appreciates the opportunity to comment on the Proposed Rule and is available to answer questions at any time. If you have questions please contact Darrick Eugene at deugene@velaw.com or 512.542.8814, or Steve Melzer at melzerls@aol.com or 432.682.7664.

Respectfully,

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Attachment A

Comparison of Class I and Class VI Wells		
	Class I Hazardous Waste	Class VI Geological Storage
Materials of Construction	Well materials compatible with injected fluid	Corrosion resistant materials required
	Tubing and packer selection based on characteristics of injected fluid	
Cements	Designed for the life expectancy of the well	Acid resistant strongly encouraged
Wellhead Corrosion Monitoring	Dependent upon injectant composition	Required
Cementing Program	Long-string (inner) casing fully cemented to the surface	Long-string (inner) casing fully cemented to the surface
Alarms/Shutoff	Automatic alarms and shutdown devices	Downhole shutoff valve required
Annulus Liquid Level Indicator	Not required	Required
Internal Mechanical Integrity Test	Annually	Waived
External Mechanical Integrity Test	Every 5 years	Annually
	Test cement at base of well annually (Radioactive tracer)	
MMV	Continue ground water monitoring until injection zone pressure cannot influence USDW	50 year post-injection monitoring period subject to Director's review

ATTACHMENT B

Technical Comments of the Texas Carbon Capture and Storage Association

In Response to EPA's Proposed Rule: Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Proposed Rule

Docket ID No. EPA–HQ–OW–2008–0390
(73 Fed. Reg. 43,492 (July 25, 2008))

Submitted December 23, 2008

By

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Technical Comments to the EPA Proposed Rules on Geologic Sequestration of CO_2

1. § 146.81 Applicability

The proposed rule provides that owners or operators of authorized Class I industrial, Class II, or Class V experimental CO_2 injection projects who seek to "convert" these wells to Class VI wells and apply for a Class VI permit may be exempted, at the Director's discretion, from the proposed casing and cementing requirements applicable to Class VI wells.

> ***EPA Proposed*** *§ 146.81(c) This subpart applies to owners and operators of permit or rule-authorized Class I industrial, Class II, or Class V experimental carbon dioxide injection projects who seek to apply for a Class VI geologic sequestration permit for their well or wells. If the Director determines that USDWs will not be endangered, such wells are exempt, at the Director's discretion, from the casing and cementing requirements at §§ 146.86(b) and 146.87(a)(1) through (3).*

It is helpful that EPA recognizes that entities may wish to convert other classes of wells (such as Class II wells used for CO_2 enhanced oil recovery projects) into Class VI wells and that flexibility is necessary for this conversion process. This flexibility should be maintained in the final rules but should be enhanced. In addition, the rules should be expanded to provide further detail on the conversion process. It is critical that owners and operators have clear and concise rules to rely on when seeking to grandfather their existing wells. This provision should be revised to limit the Director's discretion and address all variances resulting in modifications to existing wells. For instance, while the rules waive the Class VI casing and cementing requirements for existing wells being converted to Class VI wells, the rules do not address other construction or construction-related Class VI well requirements that create variances between Class VI and Class I, II and V wells. Those requirements include:

1. Down hole automatic shut-off valve with wellhead hydraulics;
2. Annulus liquid level detector;
3. Wellhead corrosion monitoring equipment; and
4. Mechanical integrity testing.

Each of these requirements applicable to Class VI wells would require retrofitting or modifications to existing wells and could make conversion of wells impracticable or excessively expensive. Rather than requiring existing wells to meet prescriptive rules that may not be necessary or applicable, the decision to grandfather an existing well should be based solely on the well's passing a mechanical integrity test without physical well modification and meeting all other Class VI permit requirements that may be met without well modification. This change could be accomplished by revising proposed § 146.81(c) as follows:

> (c) This subpart applies to owners and operators of permit or rule-authorized Class I industrial, Class II, or Class V experimental carbon dioxide injection projects who seek to

apply for a Class VI geologic sequestration permit for their well or wells. If the Director determines ~~that USDWs will not be endangered~~ **through the results of mechanical integrity testing pursuant to § 146.89 that the well is effective in preventing endangerment of USDWs,** such wells are exempt,~~ at the Director's discretion,~~ from ~~the casing and cementing requirements at §§ 146.86(b) and 146.87(a)(1) through (3)~~ **any requirement imposing physical well modifications, subject to meeting all other Class VI well requirements.**

The TxCCSA also comments on the definition of Geologic Sequestration Project referenced in this section.

> *Geologic sequestration project means an injection well or wells used to emplace a carbon dioxide stream beneath the lowermost formation containing a USDW. It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated pressure front, and displaced brine, as well as the surface area above that delineated region.*

This definition restricts geologic sequestration projects to the lowermost formation containing a USDW. Restricting injection formations to the lowermost USDW is not necessary for the protection of USDWs and would remove a vast number of viable formations from consideration. The drilling industry has shown that it can operate CO_2 injection wells in an enhanced oil recovery (EOR) context without endangering USDWs that are located below the injection zone. There should be no blanket prohibition against injection into any approved geologic zone even if above the lowermost USDW. The decision should be site-specific and based on evaluation of local geology. We fully support the change proposed by the Texas Railroad Commission in its comments.

> Geologic sequestration project means an injection well or wells used to emplace a carbon dioxide stream beneath the lowermost formation containing a USDW**, or another formation, if the Director determines that injection into the other formation will not endanger USDWs**. It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated pressure front, and displaced brine, as well as the surface area above that delineated region.

2. § 146.82 Required Class VI permit information

This section of the proposed rule sets forth the information which the owner or operator must submit to the Director in order to obtain a Class VI well permit. All of the information specified must be part of the permit application. But some data are not necessary in light of other provisions of the current proposal, and some are not attainable prior to well drilling (applicants will not drill the well until it has been approved, otherwise they risk drilling an unusable well). Still other data can only be obtained after injection activities have been initiated. Post drilling and post injection data should not be required as part of the application process but instead should be considered confirmatory data that may be submitted after they are obtained. In general, the proposed rule should be modified to require submission of only those data which are needed for consideration of the initial permit application, and only those data that may be reasonably obtained prior to commencement of installation and operation of the injection well.

> ***EPA Proposed***: *§146.82 (f) 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;*

So long as the Applicant proposes to inject CO_2 **below** the lowermost USDW, as required by the proposed rule, there is no justification to require maps and stratigraphic cross sections for the entire extent of those USDWs above the lowermost USDW, although mapping and stratigraphic cross sections in the immediate vicinity of the proposed injection locations (e.g. where the injection wells will be drilled) should still be required. Data regarding all USDWs in the AoR will likely be costly and/or difficult to collect and, except as noted above, the usefulness of those data seems questionable.

Accordingly, TxCCSA suggests that subparagraph (f) should be modified as follows:

> (f) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of ~~all~~ **the lowermost** USDW~~s~~, **all USDWs in the immediate vicinity of the proposed injection well(s),** 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;

> ***EPA Proposed*** : *§146.82(l) The results of the formation testing program as required in paragraph (j) of this section;*
> *(r) All available logging and testing program data on the well required by§ 146.87;*
> *(s) A demonstration of mechanical integrity pursuant to § 146.89;*

The requirements of subparts (l), (r) and (s) of § 146.82 cannot be met until after the well is drilled. For example, subparagraph (l) references (j), formation testing. Clearly formation testing is a drilling or post completion operation. Similarly, logging and mechanical integrity testing also are drilling or post well completion operations. Because this information will be collected post application approval, it should not be required prior to the granting of the Class VI permit.

TxCCSA suggests that EPA modify § 146.82 to eliminate subparts (l), (r) and (s) because those data do not belong in and in fact may not be available as part of a permit application.

3. §146.84 Area of review and corrective action.

EPA's proposed rule allows each applicant to define the Area of Review ("AoR") associated with the sequestration project. TxCCSA has no objection to this flexible approach as it allows the size and shape of the AoR to reflect the unique geology of each CO_2 sequestration project. However, under §146.84 (a), to define the AoR, an applicant must use a model capable of considering the physical and chemical properties of **all** phases of the injected carbon dioxide stream. TxCCSA is uncertain that there is a model that can satisfy this requirement. Accordingly, TxCCSA suggests that the proposed rule be amended as follows:

§146.84 Area of review and corrective action**.**
(a) The area of review is the region surrounding the geologic sequestration project that may be impacted by the injection activity. The area of review is based on computational modeling that**, to the extent practicable and to the extent determined to be necessary by the Director,** accounts for the **material** physical and chemical properties of ~~all~~ **critical** phases of the injected carbon dioxide stream.

4. § 146.86 Corrosiveness of the carbon dioxide stream, and formation fluids;

Under the proposed rule, the Director is required to determine and specify casing and cementing requirements to ensure that a proposed Class VI well is constructed and completed to prevent the movement of fluids into or between USDWs or into any unauthorized zones and to permit appropriate testing and monitoring. The proposed rule does not adequately explain or justify the information requirements set forth therein.

> ***EPA Proposed*** *§146.86 (b) Casing and Cementing of Class VI Wells.(1)(v) Corrosiveness of the carbon dioxide stream, and formation fluids;*

The proposed rule requires an applicant to submit to the Director information on the corrosiveness of the carbon dioxide stream, and formation fluids. Neither the proposed rule nor the Preamble adequately explains whether the information requested is corrosiveness of the combined streams of CO_2 and formation fluids, or each independent stream (which seems unnecessary). Further, the proposed rule or the Preamble should elaborate on what type of data may be acceptable –laboratory data for hypothetical streams, empirical testing, analogous wells? Clarification is requested on the aforementioned requirements.

> ***EPA Proposed*** *§146.86 (b) Casing and Cementing of Class VI Wells. (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.*
> *
> *
> *
> *(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.*

Additional proposed requirements affecting casing and cementing of Class VI wells is set forth in §§ 146.86 (b)(3) and (5) as quoted above. The requirement, to cement the casing to the surface is unnecessary, expensive and contrary to best practices. Under acceptable best practices, the long string casing would not be cemented to the surface so that the pressure between the surface casing and long string can be monitored to determine if there is migration between the long-string casing and the surface casing. The cementing requirement proposed above would limit the ability to monitor for migration of injected fluids, in this case CO_2, behind the casing. Additionally, TxCCSA's field data indicates that the proposed casing and cementing requirements are costly while providing limited, if any benefit. According to our findings, under existing Class II UIC rules, a conventional cementing program costs approximately $20,000 per well. Under the cementing program proposed for Class VI wells the cost could escalate to approximately $193,000 per well a potential $173,000 increase, representing a 10% increase in total per well costs.[1]

TxCCSA suggests an alternative that protects USDWs, but at a reasonable cost. Rather than require cementing of the long string casing to the surface, the proposed rule should require cement and cement additives to be compatible with the carbon dioxide stream and formation fluids that cover the injection zone and the confining zone, and then require standard (API, ASTM International, or comparable standards) industry cements to a certain distance above the confining zone. This would place cements that may require special additives at the point where USDWs are most effectively protected from the mixture of carbon dioxide and formation fluids that could produce carbonic acid.

TxCCSA suggests the following revision:

> §146.86 (b) Casing and Cementing of Class VI Wells. (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 across the ~~surface~~ **<u>injection zone and confining zone and an authorized distance above the confining zone, submitted by the permittee and approved by the Director</u>** ~~in one or more stages~~.
> *****
> *
> *
> (5) **<u>To protect USDWs</u>**, ~~C~~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~~ **<u>operating</u>** life of the **<u>well</u>** ~~geologic sequestration project~~ **<u>must be used through the injection zone and confining zone</u>**. 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.

5. § 146.87 Logging, sampling, and testing prior to injection well operation.

EPA's proposed § 146.87 delineates the information a permittee must collect during the drilling and construction of a Class VI well, prior to actual injection activities**.** Although the proposed rule generally allows the Director to approve alternative methods that provide equivalent or better information, it is not clear that the Director can utilize that regulatory flexibility to waive unnecessary, duplicative testing which the proposed rule requires in several subparagraphs.

[1] For a typical well completed under Class II UIC rules, the total costs equals $1,700,000.

***EPA Proposed** § 146.87 (a)(2) Before and upon installation of the surface casing:…*
(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.

The requirements in §146.87(a)(2)(ii) to secure and submit specified logs before, upon and after surface casing installation is excessive. The proposed rule fails to provide a sufficient justification for requiring a cement bond and variable density log before and upon installation of the long string casing, **and** requiring a temperature log after the casing is set and cemented. Temperature logs are seldom used in the drilling industry to determine cement characteristics as they do not provide useful data regarding the bonding of cement. The rules should be modified to allow the permittee to select between the specified logs and any other logging tool approved by the Director as follows:

§146.87(a)(2)(ii) A cement bond and variable density log **or other approved tool**, ~~and~~ **or** a temperature log after the casing is set and cemented. [see § 146.12(d)(2)(i)(B) **Criteria and Standards applicable to Class I nonhazardous wells: Construction Requirements**.]
*
*
*
(5) Any alternative methods that provide equivalent or better information and that are required of and/or approved of by the Director. **The Director may waive any log or test specified in this subparagraph.**

***EPA Proposed** §146.87 (a)((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

Once again, the proposed rule requires testing that would be of little benefit in protecting USDWs, but would impose significant costs on operators. For example, TxCCSA sees no basis to run a fracture finder log in every well. Fracture finder logs will only see minor fractures within the individual formations. The log does not provide information on whether these minor fractures can act as conduits between the injection zone and confining zone. To avoid unnecessary data collection and submittal, the rules should allow the applicant to propose and justify a logging suite based on the reservoir and geology associated with the particular CO_2 project. The Director of course should be allowed to approve, or recommend revisions to the proposed suite. This would avoid mandating unneeded testing. TxCCSA suggests the following revised rule, incorporating this proposed change:

§146.87 (a)((3) Before and upon installation of the long string casing:
(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, ~~and any other~~ **or any suite of logs submitted by the permittee and approved by** ~~logs~~ the Director **before the casing is installed** ~~requires for~~ **considering** the ~~given~~ geology ~~before the casing is installed~~; and

*
*
*

The proposed rule also requires unnecessary and duplicative logging with respect to the long-string casing.

> ***EPA Proposed*** *§146.87(a)((3) Before and upon installation of the long string casing*: *(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.*

TxCCSA suggests that the logging options it recommends with respect to surface casing also apply for the long-string casing. Thus, the proposed rule should be revised as follows:

> §146.87(a)(3)(ii) A cement bond and variable density log **<u>or other approved tool</u>**, ~~and~~ **<u>or</u>** a temperature log after the casing is set and cemented. [see § 146.12(d)(2)(ii)(C) **Criteria and Standards applicable to Class I nonhazardous wells: Construction Requirements**.]

> ***EPA Proposed*** *§146.87(b) The owner or operator must take and submit to the Director whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s). The Director may accept 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.*

TxCCSA opposes the requirement to collect cores from more than one (1) well within a CO_2 project. As a practical matter, the majority of the important physical and geophysical properties of the injection reservoir, including the particular attributes of the confining formations can and are required to be evaluated from logs and other scientific, reliable measures. A "whole core", as specified in §146.87(b) is only a very small sample of the attributes of a reservoir and a sidewall core, an even smaller sample. The former is very expensive to collect, and the latter often not available. Neither is essential given the vast amount of data otherwise required, and multiple samples, as proposed by the rule, is not reasonable. The unreasonableness of the whole core, sidewall core and extra core sampling is evident upon consideration of the sheer volume of physical evidence that this provision alone may produce. For example, in Texas there are over 5000 existing Class II CO_2 injection wells. If a small fraction of these wells are converted to Class VI CO_2 injection wells following the completion of production activities, there will be a large universe of cuttings. Where will the regulatory agency store this magnitude of cuttings? This may become a particular problem given the total number of CO_2 sequestration projects that may be proposed.

TxCCSA suggests the following:

> §146.87(b) **<u>At the specific request of the Director and only where core retrieval is possible, t</u>**~~T~~he owner or operator must take and submit to the Director **<u>a</u>** whole core~~s~~ or sidewall core~~s~~ of the injection zone and confining system and formation fluid samples

from the injection zone(s). ~~The Director may accept 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.~~

EPA Proposed *§146.87(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;
(2) Other physical and chemical characteristics of the injection and confining zones; and
(3) Physical and chemical characteristics of the formation fluids in the injection zone.

Subparagraph (d) of §146.87 provides permittees with a generic list of data that is required regarding the injection and confining zone. Fracture pressure is specified. Under the circumstances, fracture pressure should <u>only</u> be calculated, rather than "determined" as any determination based on techniques beyond mathematical calculation will require coring or perforation of the casing, potentially decreasing the mechanical integrity of the well and running directly counter to the objective of the proposed rules.

With respect to other generic data EPA seeks regarding the injection and confining zones, the proposed rule does not to provide sufficient guidance to the permittee on the scope of data required on the formation fluids and reservoir zones. TxCCSA requests clarification and specifics both with respect to the nature and type of "physical and chemical characteristics" EPA expects a permittee to submit in response to the requirements of 146.87(d) (2) & (3).

EPA Proposed *§146.87(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.*

The agency requires the submission of a proposed logging and testing schedule at least 30 days in advance of those proposed activities. Although a logging and testing schedule certainly can be designed 30 or more days in advance, the actual date that logging is performed is usually available only 24 to 48 hours in advance of actual logging operations. A mandatory 30 day notice is simply not practical for logging and testing.

TxCCSA asks that notice requirements in this subpart be adjusted to take into account the practical limitations experienced routinely in field operations. Suggested revised language is set forth below.

§146.87(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 **<u>proposed</u>** schedule of such activities to the Director **<u>at least</u>** 30 days prior to conducting the first test and submit **<u>notice at least 24 hours in advance of the conduct of any actual logging and testing.</u>** ~~**an**y changes to the schedule 30 days prior to the next scheduled test~~.

6. § 146.88 Injection well operating requirements.

> ***EPA Proposed*** *§146.88(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.*

EPA's suggested Mechanical Integrity ("MI") rule to maintain pressure on the annulus exceeding the operating injection pressure will, in most cases, result in an exceedance of the burst pressure of the casing. If the operator is required to maintain pressure on the annulus at a rate that is greater than the injection pressure (as indicated in EPA proposed §146.88(c)), monitoring the annulus pressure may not be an accurate indicator of mechanical integrity. The EPA appears to recognize this likelihood and thus allows the Director to waive the requirement. However, the rule should not require a questionable practice and then permit its waiver. Rather, the practice should only be required if the Director makes a determination that the conduct of the test will NOT cause a problem. The suggested revision is encapsulated below:

> (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. **If the Director determines that such requirement will not harm the integrity of the well,** ~~T~~the owner or operator must maintain **a positive pressure** 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~~.

> ***EPA Proposed*** *§146.88(e) The owner or operator must install and use continuous recording devices to monitor: The injection pressure; the rate, volume, 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 must install and use alarms and automatic down-hole shut-off systems, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters approved by the Director diverge beyond permitted ranges and/or gradients specified in the permit;*

The installation and use of automatic down-hole shut-off systems creates a potential avenue for leakage and is unnecessary on land-based onshore systems. Down-hole shut-off systems, more commonly used in off-shore operations, serve to shut in the well and prevent reservoir fluids from exiting the wellbore. They are used in off-shore operations because of the risk of damage to the wellhead from atmospheric or anthropogenic phenomenon, such as a hurricane causing extensive platform damage or a ship colliding with a platform. But in an onshore injection system, a down-hole shut-off system will not determine or deter leakage of fluids in the wellbore and therefore is not effective in protecting USDWs. Also, the likelihood of damage to an onshore wellhead is extremely remote. The greater risk in a Class VI onshore operation is that the mechanics of the down-hole shut-off system will be compromised or malfunction. Such a malfunction would require removal of the tubing and shut-off system equipment, thereby creating a potential unwanted migration path. The use of automatic down-hole shut-off systems should be limited to off-shore operations.

Furthermore, the requirement to continuously monitor the annulus fluid volume is impractical, because it does not provide any meaningful data regarding potential problems with the operation of the well. Requiring the continuous monitoring of the amount of annulus fluid added during operations is more practical and will reveal potential leakage paths. TxCCSA recommends the following:

> §146.88(e) The owner or operator must install and use continuous recording devices to monitor: The injection pressure; the rate, volume, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and **the volume of** ~~annulus~~ fluid added to the annulus ~~volume~~; and the owner or operator must install and use alarms and automatic ~~down-hole~~ shut-off systems, designed to alert the operator and shut ~~in~~ off the well when operating parameters such as annulus pressure, injection rate or other parameters approved by the Director diverge beyond permitted ranges and/or gradients specified in the permit. **If the operation involves off-shore injection, the owner or operator must install and use alarms and automatic down-hole shut-off systems, designed to alert the operator and shut-in the well if the wellhead is damaged or when operating parameters such as annulus pressure, injection rate or other parameters approved by the Director diverge beyond permitted ranges and/or gradients specified in the permit**;
>
> (f) If a**n** ~~down-hole~~ automatic shutdown is triggered or a loss of mechanical integrity is discovered, the owner of operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff.
> *
> *
> *

7. § 146.89 Mechanical integrity.

> ***EPA Proposed*** *§146.89(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:*
> *(3) A casing inspection log, if required by the Director.*

Among the test protocols prescribed by the proposed rule to confirm lack of significant fluid movement is a casing inspection log. Although this log is optional, it may be required by the Director. Conducting a casing inspection log will require the tubing to be pulled from a well, and that in turn substantially increases the possibility of a well control event (that is a loss of control over well operation). Accordingly, the technique should only be mandated when other testing methodologies are unavailable. TxCCSA suggests the following edit:

§146.89(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:
(3) A casing inspection log, if **a tracer survey or a temperature or noise log cannot be obtained and a casing inspection log is thus** required by the Director.

8. § 146.90 Testing and monitoring requirements.

EPA Proposed *§146.90(b) Installation and use, except during well workovers as defined in § 146.86(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;*

Consistent with our comment regarding proposed § 146.88(e) in Section 5 above, TxCCSA is unaware of a methodology to monitor the actual volume of annular fluid in the annulus on a continuous basis, and thus seeks agency clarification on this portion of the proposed rule.

EPA Proposed *§146.90*(c) *Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting and other signs of corrosion 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:*
(1) Placing coupons of the well construction materials in contact with the carbon dioxide stream; or
(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well; or
(3) Using an alternative method approved by the Director;

TxCCSA believes the requirements in EPA proposed §146.90(c) related to corrosion monitoring are inapplicable. In the vast majority of cases, the CO_2 will be transported to the injection site through pipelines, will be dehydrated prior to transportation and therefore when injected it will be non-corrosive.[2] In those instances, the test methods described in § 146.90(c)(1) and (c)(2) (except of course alternatives approved by the Director) will not provide meaningful information regarding the mechanical integrity of down-hole casing, tubing and other equipment because the CO_2 will simply not be corrosive at the surface. Consequently, to have any relevance such requirements should be reserved for situations where water saturated CO_2 is being injected.

[2] For evidence on CO_2 corrosivity in the absence of free water see Don Duttlinger, *Enhanced Recovery Intertwines Naturally With* CO_2 *Sequestration*, Tech Connections Column, January 2004, American Oil and Gas Reporter, available at http://www.pttc.org/aogr_columns_archived/aogrcojan04.htm (From the processing/injection standpoint, CO_2 is noncorrosive as long as it is dry. Proving that point, Kinder Morgan has hydro-tested the 32-year-old CRC Pipeline built in 1971 to transport CO_2. Only one minor failure occurred. After testing, the line was rated for 2,025 psi maximum operating pressure, which established a 200 psi increase over most recent ratings); see J. Layne, *Results of the Hydrotest of the 30-year old Canyon Reef Carriers* CO_2 *Pipeline*, 2003 CO_2 Flooding Conference, December 11-12, 2003, Midland,Texas (University of Texas of the Permian Basin's Center for Energy and Economic Diversification).

§146.90(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting and other signs of corrosion must be performed on a quarterly basis to ensure that ~~the~~ well components **<u>that contact water saturated carbon dioxide streams</u>** meet the minimum standards for material strength and performance set forth in § 146.86(b) by:
(1) Placing coupons of the well construction materials in contact with the carbon dioxide stream; or
(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well; or
(3) Using an alternative method approved by the Director.
<u>The requirements of this subpart are waived when the carbon dioxide stream is dehydrated to meet pipeline specifications.</u>

EPA Proposed *§146.90(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;*

The scope of this proposed requirement is not clear. Does the EPA proposal require the submittal of the actual data, or merely an analysis of the pressure fall-off test?

EPA Proposed *§146.90(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(b) and to determine compliance with standards under 40 CFR 144.12*

This section effectively proposes a "catch all" to allow the Director undefined discretion to order unlimited and unspecified additional monitoring to improve modeling and ensure compliance. Vesting the Director with such additional undefined discretional authority increases the regulatory risks of the Class VI permitting process and accordingly increases costs. In the event that experience implementing the proposed rule requires some future revisions to include additional monitoring requirements, such changes should be proposed and adopted through appropriate rulemaking procedures and based on an adequate factual and scientific record. However, adopting an open-ended power to require "any" additional monitoring, at this early stage, undermines the purpose of providing a defined set of rules that members of the public may evaluate prior to making the large investments that will be involved in a Class VI projects. Such uncertainty can only tend to increase costs, creating a barrier to capital formation and discourage geologic sequestration. Accordingly, TxCCSA would recommend deleting this section:

~~§146.90(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(b) and to determine compliance with standards under 40 CFR 144.12.~~

9. § 146.92 Injection well plugging.

> ***EPA Proposed** §146.92 (b) Well Plugging Plan. (5) The type and grade and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream;*

The proposed regulation requires the wellbore to be flushed prior to plugging and thus it is unnecessary to use cement "compatible with the carbon dioxide stream". In the absence of water, CO_2 is non-corrosive and compatible with conventional cements (see discussion under Comment #7). Accordingly, the rule should be revised as follows:

> §146.92 (b) Well Plugging Plan. (5) The type and grade and quantity of material to be used in plugging. ~~The material must be compatible with the carbon dioxide stream;~~

10. § 146.93 Post-injection site care and site closure.

The proposed rule establishes a 50 year default period for post-injection site care. There is, however, no factual or scientific basis for such an extensive period. Under EPA's Resource Conservation and Recovery Act rules, which regulate the disposal of hazardous wastes, post closure care is limited to 30 years. Defaulting to an excessively long period will increase costs and introduce greater regulatory uncertainty, which will discourage capital formation around CO_2 sequestration.

Additionally, even though the proposed rule appears to include a 50 year default post injection site care period, in reality, that deadline is illusory as it is not self executing. Under the rules, post injection site care must continue indefinitely until the Director authorizes closure. The closure approval process could take years, even decades, as the Director has no regulatory incentive to act on any post injection site care report. Meanwhile, a permittee may be required to continue unnecessary and expensive monitoring and reporting indefinitely.

Whether the post-injection site care period is site-specific, or 10 to 50 years, TxCCSA suggests that the post-injection site care provision be reconfigured to be self-executing and allow for closure at the end of that period unless the Director affirmatively acts to extend the post-injection site care period. These changes are contained in the suggested text below:

> **§ 146.93 Post-injection site care and site closure.**
> (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.
>
> (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.
>
> (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;
>
> (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(b);

(iii) A description of post-injection monitoring location, methods, and proposed frequency; and

(iv) A proposed schedule for submitting post-injection site care monitoring results to the Director.

(3) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed.

(4) The owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.

(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.

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(3) Prior to ~~authorization for~~ **<u>the expiration of the period specified in subpart (b)(1),</u>** ~~site closure~~, the owner or operator must submit to the Director a demonstration, based on monitoring and other site specific data, that the carbon dioxide plume and pressure front have stabilized and that no additional monitoring is needed to assure that the geologic sequestration project does not pose an endangerment to USDWs.

(4) **<u>If within 180 days after the submittal of the data required under subparagraph (3), the Director determines that the geological sequestration project may continue to pose an endangerment to USDWs, he shall so notify the owner or operator of his determination and the basis therefore, and</u>** ~~If such a demonstration cannot be made (i.e., if the carbon dioxide plume and pressure front have not stabilized) after the 50-year period,~~ the owner or operator must submit to the Director a plan to continue post-injection site care.

<u>(5) If within 180 days after the submittal of the data required under subparagraph (3) above the Director fails to determine and to notify the owner or operator that the geological sequestration project may continue to pose an endangerment to USDWs, site closure shall be deemed authorized by rule</u>

(c) Notice of intent for site closure.

The owner or operator must notify the Director at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. At the discretion of the Director, a shorter notice period may be allowed.

(d) After the Director has authorized site closure **<u>or site closure is authorized by rule</u>**, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.

(e) Once the Director has authorized site closure, **<u>or site closure is authorized by rule</u>**, the owner or operator must submit a site closure report within 90 days that must thereafter be retained at a location designated by the Director. The report must include:

(1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (c) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority

designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;

(2) Documentation of appropriate notification and information to such State, local and tribal authorities as have authority over drilling activities to enable such State and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and

(3) Records reflecting the nature, composition and volume of the carbon dioxide stream.

(f) Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:

(1) The fact that land has been used to sequester carbon dioxide;

(2) The name of the State agency, local authority, and/or tribe with which the survey plat was filed, as well as the address of the Regional Environmental Protection Agency Office to which it was submitted; and

(3) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(g) The owner or operator must retain for three years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.