United States Environmental Protection Agency

Underground Injection Control (UIC) Class VI Program

Summary of EPA's Responses to Public Comments Received on the Class VI Injection Well Construction Guidance

May, 2012

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Summary of EPA's Responses to Public Comments Received on the Class VI Well Construction Guidance

Introduction

In March 2011, EPA published the draft Guidance document "Class VI Well Construction Guidance for Owners and Operators" (EPA 816-D-10-008). Following publication of the draft Guidance, EPA invited the public to comment over a 60 day period ending on May 31, 2011.

EPA received unique submittals from nine commenters, representing the organizations shown in the table below:

#	Commenter	Type of Affiliation
1	American Electric Power (AEP)	Energy Industry
2	American Petroleum Institute (API)	Trade Associations
3	C12 Energy	Energy Industry
4	Carbon Sequestration Council (CSC)	Carbon Capture / Sequestration Associations
5	Clean Air Task Force; Clean Water Action; National Resource Defense Council (NRDC) (referred to as NGOs)	Environmental NGO
6	Edison Electric Institute (EEI)	Energy Industry
7	EPA Region 5	EPA Region 5
8	North American Carbon Capture and Storage Association (NACCSA)	Carbon Capture / Sequestration Associations
9	Texas RRC	State

Copies of the public comments submitted are presented in EPA document number EPA 816-R-11-021.

Comments were made on various sections of the Guidance. The table below summarizes the types of comments received.

Comment Category	Number of Comments
General	4
Disclaimer, Executive Summary, and Definitions	1
1. Introduction	1
2. Construction Requirements for Class VI Injection Wells	58
3. Operating Requirements for Class VI Injection Wells	13
4. Conclusions	11
5. References	1
Total	**89**

Please note that this document is intended to be a summary of the comments presented; while attempts were made to capture all commenter arguments and suggestions which require a response by EPA, every individual comment may not be included in this condensed document.

Contents

General Comments on Guidance

#	Commenter	Comment	EPA Response
1	**API**	Given the flexible, adaptive approach EPA has adopted toward this rulemaking, (75 FR 77241), API offers the following comments with the intent of encouraging EPA to modify the more problematic requirements of the Class VI rule through its Guidance documents where possible or through rulemaking as appropriate.	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. As stated in the disclaimer, guidance does not substitute for regulations. EPA will use guidance to clarify and explain rule requirements but not to change them. EPA is committed to implementing an adaptive approach to this rule. The current requirements were arrived at through stakeholder involvement and public comment. EPA believes they are the best approach to protecting USDWs while acknowledging site specific characteristics. If during the six year review, some rule elements have proven to be problematic, EPA will revise the requirements at that time.
2	**CSC**	One very important consideration bears emphasis because the draft well construction Guidance and the other draft documents appear to lose sight at times of the fact that – for materials of construction other than the injection tubing itself – compatibility “with fluids with which [they] might come into contact” is the important focus rather than compatibility with the carbon dioxide stream. Only the injection tubing will come into direct contact with the carbon dioxide stream before it mixes with other fluids. For everything else, compatibility is always to be assessed in accordance with the requirement in 146.86(b)(1) that [a]ll well materials must be compatible with fluids with which the materials may be expected to come into contact . . . .” We have suggested a number of places where this consideration can be more effectively reflected.	To address this comment, EPA has changed the statements on material compatibility to match the rule language.
3	**NGOs**	EPA should include specific discussions and guidance, where appropriate, for cases where sequestration is taking place in hydrocarbon reservoirs or in conjunction with Enhanced Oil Recovery. Sequestration in hydrocarbon reservoirs or in conjunction with Enhanced Oil Recovery is underrepresented or missing in the draft guidances. EPA should anticipate and discuss the special circumstances present in these fields and include guidance text accordingly. Areas where those reservoirs merit special discussion include, for example:	EPA clarifies that most of these issues are not specific to oil reservoirs and are sufficiently covered by terms such as formation fluids or fluids into which the material may come into contact. Further, EPA notes that this topic is also addressed in more depth in the Class II to Class VI transition guidance document. To address this comment, EPA added a statement to Section 2.4.2 describing additional considerations if

#	Commenter	Comment	EPA Response
		Draft Well Construction guidance: Practices such as water-alternating-gas injection can have important implications for well construction materials due to the corrosive characteristics of CO_2 in the presence of water, for example	water is to be injected into a well.
4	**NGOs**	The term “cement bond log” should be avoided as a general term, or its use defined and clarified. In a number of places in the draft guidances, EPA uses the term “cement bond log”. This term commonly refers to a technique which is currently outdated and which has significant drawbacks, such as not revealing the nature or shape of any voids in the cement but instead representing an average estimate of void space. We recommend that the term be substituted with a generic term such as “cement mapping tool”.	EPA clarifies that the Class VI rule requires evaluating the cement with a “cement bond and variable density log” [40 CFR 146.87(a)(2).] To address this comment, EPA has clarified the statement to reference “cement evaluation logs that evaluate the cement in a radial direction.”

Comments on Disclaimer, Executive Summary, and Definitions

#	Commenter	Comment	EPA Response
1	**EEI**	This draft Guidance introduces and defines terms, such as "brine," that are not defined in the Final UIC Class VI Rule. *See* Well Construction Guidance at vi. Again, instead of introducing and defining new terms, the Guidance should incorporate by reference the definitions that exist in the Final UIC Class VI Rule.	EPA has used regulatory language when available and appropriate. When EPA used terms not defined in the Class VI Rule, it did so for clarity of discussion and to provide context for these terms within GS well construction activities.

Comments on Chapter 1

#	Commenter	Comment	EPA Response
1.0 Introduction			
1	**Texas RRC**	p. 1, second paragraph, first three sentences:. The draft guidance reads as follows: "As carbon dioxide injection is different than other injection previously regulated by the UIC Program, the GS Rule sets requirements specific to carbon dioxide. Because carbon dioxide is less dense than most subsurface fluids, it is buoyant and will tend to migrate to the top of the injection zone. Carbon dioxide also has the potential to be corrosive when mixed with water." The first sentence is not true because it ignores Class II operations where CO_2 has been injected since at least 1972. The remaining sentences as drafted could be taken to describe Class II operations as well. However, Class VI activities are different from Class II CO_2 injection insofar as injection rates and pressures for Class VI are likely to be greater than Class II. And, geologic structure may be different as well. Therefore, the RRC recommends the following revision: Carbon dioxide injection in Class VI wells shares similarities with carbon dioxide injection in Class II wells (described below), but also may have differences. Differences include faster injection rates as Class VI wells are likely to pump more carbon dioxide into rocks than Class II wells. Also, Class II sites are known to have geologic structures that trap hydrocarbons and thus carbon dioxide, whereas less may be known about geologic structure at a Class VI wellsite. With respect to Class VI sites, due to possibly greater rates, greater attention may be necessary to carbon dioxide, because carbon dioxide is less dense than most subsurface fluids, and it is buoyant and will tend to migrate to the top of the injection zone. Carbon dioxide also has the potential to be corrosive when mixed with water.	To address this comment, EPA changed the section to read as follows: "While there are some similarities between carbon dioxide injection in Class VI wells and carbon dioxide injection in Class II wells, there are some important differences. These differences include higher injection rates, as Class VI wells are likely to inject more carbon dioxide into formations than Class II wells, resulting in higher pressures. Higher rates are also of concern because carbon dioxide is less dense than most subsurface fluids and will tend to migrate to the top of the injection zone. Also, Class II wells are known to inject into geologic structures that trap hydrocarbons and thus carbon dioxide, whereas less may be known initially about the geology (e.g., structure and stratigraphy) at GS sites. The time frame of Class VI injection will likely be considerably longer than is typical in Class II wells. Additionally, carbon dioxide has the potential to be corrosive in the presence of water."

Comments on Chapter 2

#	Commenter	Comment	EPA Response
2.1.2 Typical Injection Well Components Preventing Fluid Movement			
1	**CSC**	**Guidance Statement:** These annuli are required to be filled with cement in Class VI injection wells, along both the surface and the long string casing [§§146.86(b((2) and 146.86(b)(3)]. **Final Rule Language:** 146.86(b) (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. (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. **Recommended Revision:** These annuli are ~~required to be~~ typically filled with cement in ~~Class VI injection wells,~~ along both ~~the~~ surface and long string casing. **Discussion:** This statement is not strictly accurate in light of the actual requirements of §§146.86(b((2) and 146.86(b)(3). Because it is not necessary in the context of this statement to present the regulatory requirement, we recommend the revised language provided in the column to the left. Stating accurately the requirements that relate to cement in the annuli would require much greater explanation.	EPA notes that the statement reflects the Class VI Rule, which requires cementing to the surface. To address this comment, EPA clarified that the Class VI Rule provides flexibility if cement staging cannot be accomplished.
2	**API**	The EPA GS rule is silent on the use of liners, which have been proven to be safe and effective. Liners installed on the bottom of the well and across the injection zones are common and are very effective for downhole controlled dispersion of designated injectants. It is very common to install a liner on the bottom of the well if the wellbore construction and wellbore integrity are sufficient without adding another complete string of casing from the surface and through the injection zone. When a liner is lowered to the bottom of the wellbore, it is securely placed above the bottom of the casing and cemented behind the liner. This is a proven, very safe and successful method to ensure that the injectant is confined within the wellbore and the designated injection zone. If wording allowing the use of liners is not added to the Guidance, all future injection wells will require long-strings with no exceptions. If the long string fell short of the storage formation by ten feet, it may not be possible to add another long string, and the well would have to be abandoned if liners were not allowed. A third string is not always possible technically and commercially.	To address this comment, EPA has added a discussion of liners to the Guidance.
3	**CSC**	**Guidance Statement:** The construction materials selected for the casing and the casing design must be appropriate for the fluids and stresses encountered at the site-specific down-hole environment [§146.86(b)(1)]. **Recommended Revision:** The construction materials selected for the casing	EPA updated the Guidance to reflect the commenter's suggested change.

#	Commenter	Comment	EPA Response
		and the casing design must be appropriate for the fluids and stresses encountered in ~~at~~ the site-specific down-hole environment [§146.86(b)(1)]. **Discussion:** Generally a good statement, but the use of "in" rather than "at" would be clearer.	
4	**CSC**	We have three concerns about the way long string casing is addressed in the draft Guidance. First, we agree with the American Petroleum Institute (API) which has noted that the draft Guidance does not acknowledge the important role that can be played by liners in well construction. Liners provide a very safe and effective method to ensure that the injectate is confined within the wellbore and the designated injection zone. The Guidance should recognize that liners can be used to extend the long string casing to the injection zone.	To address this comment, EPA added a discussion of liners to the Guidance.
5	**Texas RRC**	p. 6, first paragraph, last sentence. The RRC recommends the following revisions: "Therefore, the casing must be manufactured of materials that are [~~made out of a material that is~~] compatible with fluids with which it might come into contact [40 CFR §146.86(b)(1)].	EPA updated the Guidance to reflect the commenter's suggested change.
6	**CSC**	**Guidance Statement:** The surface casing is the largest in diameter and typically extends from the ground surface through the base of the lowermost USDW. **Final Rule Provisions:** 146.86(b) (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. **Recommended Revisions:** Surface casing ~~is the largest in diameter and~~ typically extends from the ground surface through the base of the lowermost USDW. **Discussion:** The wording of this statement should be revised to eliminate the reference to "largest in diameter" as that could be conductor casing rather than surface casing. In addition, the use of "the" with surface casing suggests a single string when the regulation allows the use of multiple strings to for the surface casing.	To address this comment, EPA changed the discussion to read as follows: "The surface casing is the largest in diameter. It must extend from the ground surface through the base of the lowermost USDW [40 CFR 146.86(b)(2)]." EPA clarifies that a conductor casing, if used, would be larger.
7	**Texas RRC**	p. 6, second paragraph, second sentence. The RRC recommends the following revisions: "This casing is emplaced and cemented into the bore hole from the base of the lowermost USDW [~~(bottom of the lowermost USDW)~~] up to the ground surface, serving to both prevent fluids from entering USDWs and prevent migration of fluids between USDWs and other formations, as the casing	EPA updated the Guidance to reflect the commenter's suggested change.

#	Commenter	Comment	EPA Response
		isolates the injection fluid.	
8	**CSC**	**Final Rule Provisions:** The smallest diameter casing extends into the injection zone and is referred to as the long string casing. . . . The GS Rule requires the long string casing extend from the ground surface all the way down to the injection zone [40 CFR §146.86(b)(3)]. **Recommended Revisions:** 146.86(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. **Discussion:** The EPA GS rule does not address the use of liners, which have been proven to be safe and effective. Liners installed on the bottom of the well and across the injection zones are common and are very effective for downhole controlled dispersion of designated injectate. It is very common to install a liner on the bottom of the well if the wellbore construction and wellbore integrity are sufficient without adding another complete string of casing from the surface and through the injection zone. When a liner is lowered to the bottom of the wellbore, it is securely placed above the bottom of the casing and cemented behind the liner. This very safe and effective method can ensure that the injectate is confined within the wellbore and the designated injection zone. Wording allowing the use of liners should be added to the Guidance to clarify that the requirement for long string casing to extend "to the injection zone" should not be read to preclude the use of liners. If a long string were to fall short of the storage formation by ten feet, it might not be possible to add another long string, and the well would have to be abandoned if liners were not allowed. A third string is not always possible technically and commercially.	To address this comment, EPA has added a discussion of liners to the Guidance.
9	**Texas RRC**	p. 6, second paragraph, fourth sentence:. The RRC recommends the following revisions: "The long string casing <u>is routinely</u> [~~can be~~] perforated in the injection zone to allow fluid to flow out of the injection well and into the injection formation.	EPA updated the Guidance to reflect the commenter's suggested change.
10	**CSC**	**Guidance Statement:** If the well is very deep, there may be one or more intermediate casings of intermediate diameter between the surface casing and the long string casing. These casings would be cemented in place as well [§146.86(b)(3)]. **Final Rule Provisions:** 146.86(b) (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.	To address this comment, EPA revised the Guidance to reflect the rule's allowance of more than one surface casing string.

#	Commenter	Comment	EPA Response
		Discussion: The Guidance should be revised to recognize that one or more strings of intermediate casings may also be included in surface casing and cement strings.	
11	**Texas RRC**	p. 7, first paragraph, first sentence. The RRC recommends the following revisions: "Cement is important for providing structural support of the casing, preventing contact of the casing with corrosive formation fluids, and preventing vertical movement of fluids and gases, including carbon dioxide.	EPA updated the Guidance to reflect the commenter's suggested change.
12	**Texas RRC**	p. 7, fourth paragraph, first sentence. The RRC recommends the following revisions: "A packer is a sealing device at the lower end of the tubing which keeps fluid from migrating from the injection zone into the annulus between the long string casing and tubing."	EPA updated the Guidance to reflect the commenter's suggested change.
2.2.1 Design Considerations			
13	**Texas RRC**	p. 8, second complete sentence. The RRC recommends the following revisions: "The casing and radius of curvature of the well should be designed so that any equipment/tool that may be used in the well will pass [~~fit~~] without getting stuck."	EPA updated the Guidance to reflect the commenter's suggested change.
14	**Texas RRC**	p. 8, third paragraph, first sentence. The sentence states that "The owner or operator of the well must submit to the UIC Program Director construction plans, including casing diameter, radius of curvature, and angle of deviation at the time of the permit application [§146.82(a)(12)]." The RRC was unable to find the terms "radius of curvature, and angle of deviation" in the GS rule. Also, subpart §146.82(a)(12) references §146.86, where numerous well construction requirements are listed. Therefore, the RRC recommends the following revisions: "The owner or operator of the well must submit to the UIC Program Director construction plans in accordance with §146.90, regarding testing and monitoring requirements. The UIC Program Director may require that the construction plans include radius of curvature and angle of deviation.	To address this comment, EPA revised the paragraph to read as follows: "The owner or operator of the well must submit construction plans to the UIC Program Director at the time of the permit application [40 CFR 146.82(a)(12)]. Items such as casing diameter, radius of curvature, and angle of deviation will typically be included in such plans."
15	**Texas RRC**	p. 8, third paragraph, second sentence. The RRC recommends the following revisions: "They must also submit a Testing and Monitoring Plan [~~which would include the tests and specific pieces of equipment to be used during testing and logging of the well [§146.82(a)(15)]~~] in accordance with §146.90, regarding testing and monitoring requirements."	To address this comment, EPA has moved the regulatory citation to clarify what is required. See above response for the revised text.
2.3 Plan and Design Information to Submit to the UIC Program Director With a Class VI Injection Well Permit Application			
16	**Texas RRC**	pp. 8-9, last paragraph, second sentence. The RRC recommends the following revisions: "The UIC Program Director will be evaluating the information submitted on the proposed injection well requirements [~~casing diameter, deviation angle, and radius of curvature~~] and compare that information to [~~the~~	EPA updated the Guidance to reflect the commenter's suggested change.

#	Commenter	Comment	EPA Response
		~~diameters and lengths of the various pieces of~~] related procedures and equipment proposed for use in the Testing and Monitoring Plan for the sake of consistency."	
2.4.1 Types of Stresses			
17	**CSC**	**Guidance Statement:** The GS Rule requires that the well must be constructed to withstand anticipated stresses, last the lifetime of the project, and be compatible with the carbon dioxide stream or subsurface reaction products [§146.86(b)(1)]. **Final Rule Language:** 146.86(b) (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. . . .. **Recommended Revision:** The GS Rule requires that the well must be constructed to withstand anticipated stresses, last the lifetime of the project, and be compatible with ~~the carbon dioxide stream or subsurface reaction products~~ fluids with which the materials may be expected to come into contact [§146.86(b)(1)]. **Discussion:** The statement in the Guidance does not accurately state the requirement of the regulation. If it is presented as a restatement of the rule, it must be accurate. If some other point is to be made, such as what may have contributed to the composition of the fluids with which the materials may be expected to come into contact, then that point should be made without attempting to present it as what the rule "requires".	To address this comment, EPA revised the paragraph to better reflect rule requirements. The discussion now reads: "The Class VI Rule requires that the well be constructed to withstand anticipated stresses, last the lifetime of the project, and be compatible with fluids with which the materials may be expected to come into contact [40 CFR 146.86(b)(1)]."
2.4.2 Corrosion Considerations			
18	**CSC**	**Guidance Statement:** In addition to being designed to withstand stresses, well materials must also be able to withstand corrosive forces [§§146.86(b)(1) and 146.86(c)(1)]. **Recommended Revision:** In addition to being designed to withstand stresses, well materials should ~~must~~ also be able to withstand the corrosive forces inherent in any fluids with which the materials may be expected to come into contact [§§146.86(b)(1) and 146.86(c)(1)]. **Discussion:** This should not be presented as if it is a restatement of a regulatory requirement because it is not an accurate reflection of the rule. It would be more accurate to state that well materials should be compatible with corrosive fluids if they are expected to come into contact with corrosive fluids.	To address this comment, EPA revised the statement to clarify the rule requirements. The statement now reads: "In addition to being designed to withstand stresses, well materials must also be compatible with any fluids with which they may be expected to come into contact [40 CFR 146.86(b)(1) and 146.86(c)(1)]."
19	**CSC**	**Guidance Statement:** When carbon dioxide combines with water, carbonic	To address this comment, EPA added a sentence

#	Commenter	Comment	EPA Response
		acid is formed. Carbonic acid is corrosive to steel and other metals. It can react with cement and alter the C-S-H and calcium hydroxide material found in typical Portland cements. **Discussion:** The Guidance should go further to note that, in the well bore, brine (which will presumably be alkaline) will be present rather than water. So, if acid is created, that will probably result in an reaction with the alkaline brine which might result in a decrease of acidity.	discussing the need to consider interactions with formation fluids.
20	**AEP**	First paragraph of section 2.4.2. (p. 13 lines 9-13): In the well bore, brine (which will presumably be alkaline) will be present rather than water. So, if acid is created, it will probably be mitigated by the alkalinity of the brine, which might result in a decrease of acidity.	EPA notes that the Guidance mentions buffering by the formation a few paragraphs after the subject paragraph. The Guidance also states that determining what is appropriate for the fluids with which the well will come into contact will be highly site-specific and may have varying effects. To address this comment, EPA has added a sentence discussing the need to consider interactions with formation fluids.
21	**CSC**	**Guidance Statement:** If the water content of the injectate stream is higher than 50 ppm, then corrosion resistant materials are suggested on all components of the injection well that would come into contact with the carbon dioxide stream. **Discussion:** We have a concern about this limit, as it seems arbitrary. Corrosion as a result of water presence will be a well-specific issue, because it takes a certain amount of time for CO2 and water to create carbonic acid (and thus the corrosion risk). Thus, if the combined injection stream were traveling a great distance before injection, the potential for corrosion is heightened because of the length of time available for the reaction. If the stream were traveling a short distance, a greater content of water (perhaps higher than 50ppm) could safely be tolerated without risk of corrosion. There are a number of other issues that will impact corrosion risk. The 50 ppm limit needs to be justified, and ideally the operator should propose and justify the decision they feel is best, pending approval by the Director.	To address this comment, EPA added a reference to API literature citing the 50 ppm figure. EPA also added language clarifying that the Director has discretion over appropriate water levels based on consideration of site-specific factors.
22	**AEP**	Page 13. second paragraph: What is the support documentation for the number reference "higher than 50 ppm?" How does EPA know that this amount of water will make the CO2 stream corrosive?	To address this comment, EPA added a reference to API literature citing the 50 ppm figure. EPA also added language clarifying that the Director has discretion over appropriate water levels based on consideration of site-specific factors.
23	**C12**	**Corrosion Considerations (Section 2.4.2)**	EPA reviewed the suggested reference, and notes that it applies to carbon dioxide pipelines and not

#	Commenter	Comment	EPA Response
		Description Regarding the maximum allowable water content of the injectate stream / corrosion-resistant materials of the well, the Guidance states: If the water content of the injectate stream is higher than 50 ppm, then corrosion-resistant materials are suggested on all components of the injection well that would come into contact with the carbon dioxide stream.4 The limit of 50 ppm does not seem to be related to any particular study on this topic. While it is true that most of the existing CO2 streams in operation adhere to 50 ppm as an upper limit, this has been driven in large part by the absence of water from the process in the first place. Based purely on corrosion considerations, up to 500 ppm was deemed acceptable by independent experts for pipelines. 5 **Necessary Changes** EPA should revise the water content limitations to be consistent with corrosion resistance tests done by independent entities. As noted above, at least one study suggests the limit should be 500 ppm, not 50 ppm as noted in the Well Construction Guidance. Well Construction Guidance, p. 13. 5 See Erika de Visser, Chris Hendriks, Maria Barrio, Mona J. Mølnvik, Gelein de Koeijer, Stefan Liljemark, Yann Le Gallo, "Dynamis CO2 quality recommendations", International Journal of Greenhouse Gas Control 2, p.478 – 484, (2008).	geologic injection. To address this comment, EPA added a reference to API literature citing the 50 ppm figure. EPA also added language clarifying that the Director has discretion over appropriate water levels based on consideration of site-specific factors.
24	**NGOs**	EPA should include a discussion of the nature of injectate under Corrosion Considerations (p. 12). In addition to the water content of the carbon dioxide, it is also necessary to consider whether water itself will be injected. In Enhanced Oil Recovery projects, for example, operators sometimes chose to alternate CO2 injection with water injection (referred to as Water Alternating Gas, or WAG). The presence of water has a direct effect on corrosion.	To address this comment, EPA added language discussing the need for corrosion resistant materials if water is being injected.
2.4.3 Stress and Compatibility Information to Submit to the UIC Program Director with a Class VI Injection Well Permit Application			
25	**AEP**	Page 14. second bullet. "Corrosiveness" could be a subjective term. Does EPA's use of this term refer to pH or corrosiveness with respect to a certain material?	EPA clarifies that the word corrosiveness reflects Class VI Rule language. To address this comment, EPA has added language discussing how to determine the corrosiveness of

#	Commenter	Comment	EPA Response
			the carbon dioxide stream.
26	**CSC**	**Guidance Statement:** The materials proposed to be used will be compared to the information about the corrosiveness of the injectate and its chemical composition. **Discussion:** 'Corrosiveness' would be a subjective term. Corrosiveness in term of what (pH or anything else ?). Also if it is with respect to a material?	EPA clarifies that the word corrosiveness reflects Class VI Rule language. To address this comment, EPA has added language discussing how to determine the corrosiveness of the carbon dioxide stream.
2.5 Cementing the Casing			
27	**API**	The limitation that caprock will never be able to be fractured is excessive as a categorical statement. Cases of very long caprock intervals should permit some latitude to have a fracture extend into it by some percentage.	EPA notes that this sentence reflects the Class VI Rule and was supported by state regulators. EPA will review this requirement during the six year review if field experience shows it is necessary.
28	**CSC**	**Guidance Statement:** The GS Rule requires that the surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of single or multiple strings of casing and stages of cement [§146.86(b)(2)]. **Final Rule Language:** 146.86(b) (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. **Recommended Revision:** The GS Rule requires that []~~the~~ surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of single or multiple strings of casing and stages of cement [§146.86(b)(2)]. **Discussion:** Dropping the use of "the" in front of "surface casing" will help to avoid misleading.	EPA updated the Guidance to reflect the commenter's suggested change
29	**Texas RRC**	Page 14, last paragraph, second and third sentences:. The RRC recommends the following revisions: "A long string casing must extend through [~~to~~] the injection zone and be cemented to the surface [§146.86(b)(3)]. When cement cannot be recirculated to the surface, and the owner or operator can demonstrate by this using logs, it may be permitted [~~is permissible~~] to use staged cementing to achieve cementing to the surface [§146.86(b)(4)]."	To address this comment, EPA changed the section to read: "A long-string casing must extend at least to the injection zone and be cemented to the surface [40 CFR 146.86(b)(3)]. EPA recommends that the exact depth of the long-string casing be determined in consultation with the UIC Program Director in order to optimize both protection to USDWs and the GS capability of the well. When cement cannot be recirculated to the surface, as demonstrated through the use of logs, it may be acceptable to use staged cementing to achieve cementing to the surface [40 CFR 146.86(b)(4)]."
30	**API**	The requirement that the long-string extends "to" the injection zone should be clarified in the Guidance. The phrase "to the injection zone" is extremely vague	To address this comment, EPA revised the section to read: "A long-string casing must extend at least

#	Commenter	Comment	EPA Response
		and could be perceived as just penetrating the injection zone when optimization of injection would entail the long-string extending completely through the injection zone and possibly into the layer below the injection zone. Accordingly, the Guidance should clarify that this means that the long string (or longstring with liner – see later comment #1 below) must "extend *at least* to the injection zone".	to the injection zone and be cemented to the surface [40 CFR 146.86(b)(3)]. EPA recommends that the exact depth of the long-string casing be determined in consultation with the UIC Program Director in order to optimize both protection to USDWs and the GS capability of the well. When cement cannot be recirculated to the surface, as demonstrated through the use of logs, it may be acceptable to use staged cementing to achieve cementing to the surface [40 CFR 146.86(b)(4)]."
31	**CSC**	**Guidance Statement:** A long string casing must extend to the injection zone and be cemented to the surface [§146.86(b)(3)]. **Final Rule Provisions:** 146.86(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. **Discussion:** The requirement that the longstring extend "to" the injection zone should be clarified in the Guidance. The phrase "to the injection zone" is vague and could be perceived as just allowing penetration of the injection zone when optimization of injection might entail the long-string extending completely through the injection zone and possibly into the layer below the injection zone. Accordingly, the Guidance should clarify that this approach is permissible.	To address this comment, EPA changed the section to read: "A long-string casing must extend at least to the injection zone and be cemented to the surface [40 CFR 146.86(b)(3)]. EPA recommends that the exact depth of the long-string casing be determined in consultation with the UIC Program Director in order to optimize both protection to USDWs and the GS capability of the well. When cement cannot be recirculated to the surface, as demonstrated through the use of logs, it may be acceptable to use staged cementing to achieve cementing to the surface [40 CFR 146.86(b)(4)]."
32	**Texas RRC**	Page 15, first paragraph. The RRC recommends the following revisions: "As previously discussed, the surface casing provides stability to the well bore and typically allows the amount of drilling mud used in the deeper portions of the well to be decreased. By extending it through the base of the lowermost USDW, the surface casing also seals off USDWs and other permeable zones from deeper intervals of the well bore. Thus, it [~~and~~] provides an additional barrier to deep fluid or injectate migration into a USDW if the tubing and long string casing should fail. Cementing of the long string casing serves to seal off the well bore and may prevent [~~prevents~~] fluid or injectate leaks through [~~from~~] the casing from entering a permeable zone, such as a USDW. If the cement was absent, and there was a tubing and casing failure, carbon dioxide could enter a permeable zone and then potentially migrate into USDWs through an empty annulus, faults, or abandoned wells, which would be a permit violation and potentially harm USDW's [~~failure of mechanical integrity~~]. This would result in cessation of injection [§146.88(f)]. Cementing the casing also [~~prevents fluids from traveling up the annulus and protects the casing~~] protects it from exposure	To address this comment, EPA updated the Guidance to reflect the commenter's suggested change. However, EPA did not use the word "deep" to modify the term "fluid," because the casing protects against all fluid movement, not just deep fluid.

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		to carbonated brine and other corrosive fluids."	
33	**CSC**	**Guidance Statement:** The GS Rule requires use of centralizers in the long string casing [§146.86(b)(3)], and in all other cementing processes, centralizers are recommended. **Final Rule Provisions:** 146.86(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. **Discussion:** This is well stated and carefully tracks the rule requirement, separating what is required from what is added as a recommendation.	EPA acknowledges the comment.
34	**Texas RRC**	Page 15, fifth paragraph, second and third sentences. The RRC recommends the following revisions: "During well drilling, fluid or mud is circulated through the well bore to lubricate the drill bit and remove rock <u>cuttings</u> [~~debris~~] generated during drilling. The pressure created by <u>a column of</u> [~~the circulated~~] drilling mud also serves to prevent fluids from intruding into the well bore from the formation.	EPA updated the Guidance to reflect the commenter's suggested change.
35	**Texas RRC**	Page 16, first complete sentence.. The RRC recommends that EPA delete this sentence: "Sophisticated equipment is commonly used to precisely control drilling fluid pressure and maintain the proper pressure throughout the entire process." Drilling fluid pressure is controlled by changing its density, and such changes are based on experience in the area and on hole conditions.	To address this comment, EPA clarified that the statement refers to advanced drilling techniques such as closed loops.
2.5.1 Different Stage Options for Cementing			
36	**API**	Similar issue to #2, above, EPA should not require *surface casing* to be cemented to surface in every case. EPA should amend the Guidance to provide for top-off. If cement does not reach the surface or falls back when the pump stops, it's common to pump cement down from the surface and into the outside of the surface casing with a 1" pipe. This is commonly referred to as "1 inch or top-off with 1 inch". It is a very common practice because the cement level often falls due to its weight as the cement fills voids in the wellbore on the outside of the casing. The process is common and EPA should refer to the process in the Guidance.	To address this comment, EPA added a paragraph to clarify issues regarding topping off cement.
37	**Texas RRC**	Page 19, second complete paragraph. The RRC recommends that EPA clarify or revise this paragraph. A cement column only " half as high" would appear to violate the rule requiring cement from the bottom of casing to the surface. Also "being sure the cement has reached the bottom of the casing" creates many problems with respect to the rule(s) and may create problems with the well. What is described is somewhat like a Bradenhead squeeze, which is not allowed in Texas. Finally, the location of cement can be found using cement bond logs, not gamma logs.	To address this comment, EPA revised the paragraph as follows: "Another option for cementing is called reverse circulation cementing. In this form of cementing, cement is circulated directly down the annulus between the casing and formation. This technique reduces the bottom hole pressure exerted by the cement column because, instead of the cement traveling all the way down the tubing and then up the exterior of the casing, the

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			cement column only extends from the surface to the bottom of the hole. It often requires use of a lighter weight cement and is more difficult to accomplish than standard cementing. There may be some difficulty in reverse cementing associated with ensuring that the cement has reached the bottom of the casing. The location of the cement can be found using a number of logging tools.”
38	**NACCSA**	Another unfortunate reference is the term “Opening bomb” that appears in Figure 6 on p. 18 of the guidance. If statements and references such as these are retained, we recommend that they be explained and put into context, with ample citation to the literature documenting the low risks accompanying site operations. (see e.g. J. Heinrich, “Environmental Assessment of Geologic Storage of CO2” Massachussettes Institute of Technology (2003) (“environmental issues arising from CO2 flooding seem to be inconsequential)	EPA notes that the Guidance is not intended to serve as a risk analysis, but rather provide guidance on how to meet rule requirements. To address this comment, EPA clarified the use of the term opening bomb.
2.5.2 Cementing Information to Submit to the UIC Program Director with the Class VI Injection Well Permit Application			
39	**Texas RRC**	Page 19, last paragraph, fifth sentence The RRC recommends the following revisions: “A cement evaluation log that radially investigates the cement for each casing <u>string</u> must be submitted to the UIC Program Director upon installation of the casing [§146.87(a)(2),(3)].	EPA updated the Guidance to reflect the commenter’s suggested change.
40	**Texas RRC**	Page 20, first complete paragraph, first sentence Whether or not a cementing method is capable of circulating to the surface can only be determined at the wellsite. Therefore, the RRC recommends the following revisions: “The UIC Program Director will review the proposed cementing method to determine if it is <u>likely to</u> [~~capable of~~] circulating to the surface.	To address this comment, EPA changed the sentence to read: “The UIC Program Director should review the proposed cementing method to determine if cement can be circulated to the surface.”
2.5.3 Cement Compatibility			
41	**CSC**	**Guidance Statement:** As with other well components, the cement and any additives to the cement must be compatible with the carbon dioxide stream [§146.86(b)(5)]. **Final Rule Language:** (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. **Recommended Revision:** As with other well components, the cement and any additives to the cement must be compatible with the carbon dioxide stream <u>and formation fluids</u> [§146.86(b)(5)]. **Discussion:** The statement as presented is not accurate because overall	EPA updated the Guidance to reflect the commenter’s suggested change.

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		compatibility is always to be assess by the requirement in 146.86(b)(1) that [a]ll well materials must be compatible with fluids with which the materials may be expected to come into contact . . . . By stating that cement and cement additives "must be compatible with the carbon dioxide stream and formation fluids", subsection (b)(5) is simply seeking to reflect that requirement, not impose a new requirement. In any event, the restatement of the requirement should not be truncated as it currently is.	
42	**NGOs**	EPA should provide more detailed guidance on selecting the appropriate cement formulation (p. 22). EPA states that "the conditions the cement will experience can be predicted and the cement designed to better resist those conditions" but does not provide any details on how to perform such an evaluation or what selection criteria to use. Further details in needed in order to aid operators and Directors.	EPA clarifies that, because of the variability in site conditions and the relative lack of experience with these types of wells, it is difficult to provide detailed guidance on the proper cement. EPA may update the guidance in the future as additional experience is gained.
43	**Texas RRC**	Page 22, second paragraph, last sentence. Lines 15-17. The RRC recommends the following revision: "Non-Portland cements which are not <u>as</u> susceptible to attack by carbon dioxide are also available, including phosphate based, pozzolan-lime, gypsum, microfine, expanding cements, calcium aluminate, latex, resin or plastic cements, and sorel cements.	EPA updated the Guidance to reflect the commenter's suggested change.
2.6 Selecting the Tubing and Packer			
44	**Texas RRC**	Page 22, third paragraph, last sentence. The RRC recommends the following revisions: "<u>The</u> [~~In the casing of the tubing, the burst strength~~] <u>tubing</u> must be designed <u>with burst strength</u> to withstand the injection pressure and <u>with</u> the collapse strength to withstand the pressure in the annulus between the tubing and the casing."	EPA updated the Guidance to reflect the commenter's suggested change.
45	**Texas RRC**	Page 22, fifth paragraph, second sentence. The RRC recommends the following revisions: "Proper materials for packers are important as they are likely to come into contact with carbon dioxide<u>, or corrosive</u> [~~saturated~~] brines at some point during the project life.	To address this comment, EPA revised the sentence to read as follows, "Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at some point during the project life."
46	**NGOs**	EPA should consider the drawbacks of its recommendations on packer placement and clarify the nature of its recommendation (p. 22). The guidance states that, to obtain the best measurement of the quality of the cement bond, EPA recommends placing the packer near the top of the confining layer. This is a confusing recommendation, as when the well is initially logged to determine cement integrity and placement, it would be logged before the tubing and packer are installed. It is not clear whether this recommendation is	To address this comment, EPA changed the statement to clarify the factors regarding packer placement, The statement now reads as follows: "Packers are often made from a hardened rubber such as Buna-N or nitrile rubbers and are nickel plated. Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at

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		meant to address logging later in the life of the well. Logging through tubing also presents a risk of getting logging tools stuck in the well due to the small diameter. EPA should rewrite its recommendation and include separate discussions of the initial cement evaluation logging run, which will occur prior to commencement of injection, and subsequent logging runs that will occur when the well is operating as an injector. For the initial logging run the tubing and packer will not be installed in the well and therefore the ability to obtain the highest quality measurement will not be dependent on packer placement. Furthermore, packer placement should be based on operational considerations, such as minimizing the amount of production casing that will come into contact with the injectate, and not on the ability to obtain cement evaluation logs. For subsequent cement evaluation, when the tubing and packer are installed, EPA should include a discussion of the various options for obtaining logs and pros and cons of each. One option would be to pull the tubing and packer from the well. The benefit of this option is that the cement evaluation tool will be able to make contact with the production casing but removing the tubing and packer can result in mechanical integrity or operational risks. The second option would be to log through the tubing. The benefit of this option is that the tubing and packer do not have to be removed from the well but the log will be of lower quality and there is also a risk of getting the logging tools stuck due to the smaller diameter of the tubing.	some point during the project life. The packer must be compatible with any fluids it may come into contact with [40 CFR 146.86(c)(1)]. Placement of the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed on well components. The owner or operator should consider these factors, in consultation with the UIC Program Director, in order to select the best location for the packer according to project and site-specific circumstances.”

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47	**API**	On page 22 (section 2.6) EPA states that: "Most well logs used to measure the quality of the cement bond perform best when run directly against the casing. Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer near the top of the confining layer to obtain the best results." API notes that many cement logs do not need to run directly against the casing to measure the integrity of the cell, although some do. Additionally, packer placement can impact the ability to test wellbore integrity, the mechanical stress on well components during operation, and the risks to tools and equipment during well intervention. Because of this, API recommends the paragraph be changed to read as follows: "Well logging of the confining zone can be affected by packer placement. Therefore, to obtain the best measurement of the quality of the cement through the confining layer as possible, while not creating unnecessary risks, EPA recommends placing the packer near the top of the confining layer to obtain the best results, recognizing that this approach may need to be modified based on well-specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment."	To address this comment, EPA changed the Guidance to clarify the factors regarding packer placement. The statement now reads as follows: "Packers are often made from a hardened rubber such as Buna-N or nitrile rubbers and are nickel plated. Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at some point during the project life. The packer must be compatible with any fluids it may come into contact with [40 CFR 146.86(c)(1)]. Placement of the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed on well components. The owner or operator should consider these factors, in consultation with the UIC Program Director, in order to select the best location for the packer according to project and site-specific circumstances."
48	**CSC**	**Guidance Statement:** Most well logs used to measure the quality of the cement bond perform best when run directly against the casing. Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer near the top of the confining layer to obtain the best results. **Recommended Revisions:** ~~Most well logs used to measure the quality of the cement bond perform best when run directly against the casing.~~ Well logging of the confining zone can be affected by packer placement. Therefore, to obtain the best measurement of the quality of the cement through the confining layer as possible, <u>while not creating unnecessary risks,</u> EPA recommends placing the packer near the top of the confining layer to obtain the best results, <u>recognizing</u>	To address this comment, EPA changed the Guidance to clarify the factors regarding packer placement. The statement now reads as follows: "Packers are often made from a hardened rubber such as Buna-N or nitrile rubbers and are nickel plated. Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at some point during the project life. The packer must be compatible with any fluids it may come into contact with [40 CFR 146.86(c)(1)]. Placement of

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		<u>that this approach may need to be modified based on well specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment.</u> **Discussion:** Many cement logs do not need to run directly against the casing to measure the integrity of the cell, although some do. Additionally, packer placement can impact the ability to test wellbore integrity, the mechanical stress on well components during operation, and the risks to tools and equipment during well intervention. Accordingly, we agree with the recommended revision submitted by the American Petroleum Institute (API).	the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed on well components. The owner or operator should consider these factors, in consultation with the UIC Program Director, in order to select the best location for the packer according to project and site-specific circumstances."
49	**C12**	**Packer Positioning (Section 2.6)** **Description** The Guidance states with regards to "Selecting the Tubing and Packer" that: Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer <u>near the top of the confining layer</u> to obtain the best results.6 The EPA seems to recommend placing the packer near the top of the confining zone (instead of the bottom). This is inconsistent the well diagrams that are included in the Guidance (Figure 3), and also with common practice of placing the injection packer as close to the perforated interval as possible, in order to bring in instruments such as passive seismic geophones, pressure, and temperature probes all as near the injection perforations as possible. **Necessary Changes** In order to accomplish safe injections, allowing for direct and indirect measurements of plume and pressure performance, in accordance with the UIC Rules7 the passage from the Guidance excerpted above should be altered as follows: **"Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, <u>and to allow for crucial</u>**	To address this comment, EPA changed the Guidance to clarify the factors regarding packer placement. The statement now reads as follows: "Packers are often made from a hardened rubber such as Buna-N or nitrile rubbers and are nickel plated. Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at some point during the project life. The packer must be compatible with any fluids it may come into contact with [40 CFR 146.86(c)(1)]. Placement of the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed

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		monitoring instruments to be placed as close as possible to the injection perforations, EPA recommends placing the packer above the perforated interval in the injection formation ~~near the top of the confining layer to obtain the best results.”~~ 6 Well Construction Guidance, p. 22 (emphasis added). 7 40 CFR §146.90 states (in part): “Testing and monitoring associated with geologic sequestration projects must, at a minimum, include: (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: (1) Direct methods in the injection zone(s); and (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.	on well components. The owner or operator should consider these factors, in consultation with the UIC Program Director, in order to select the best location for the packer according to project and site-specific circumstances.”
50	**Texas RRC**	Page 22, fifth paragraph, last sentence The RRC recommends the following revisions: “Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer within 100 feet above the perforations and within a cemented interval [~~near the top of the confining layer~~] to obtain the best results.	To address this comment, EPA changed the Guidance to clarify the factors regarding packer placement. The statement now reads as follows: “Packers are often made from a hardened rubber such as Buna-N or nitrile rubbers and are nickel plated. Proper materials for packers are important as they are likely to come into contact with corrosive fluids such as carbon dioxide or corrosive brines at some point during the project life. The packer must be compatible with any fluids it may come into contact with [40 CFR 146.86(c)(1)]. Placement of the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed on well components. The owner or operator should consider these factors, in consultation with the UIC

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			Program Director, in order to select the best location for the packer according to project and site-specific circumstances."
2.7 Additional Well Construction Information to Submit to the UIC Program Director with a Class VI Injection Well Permit Application			
51	**CSC**	**Guidance Statement:** The owner or operator must submit the following information to the UIC Program Director at the time of the permit application [§146.86(c)(3)(i)-(vii)]: **Final Rule Provisions:** (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; (ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids; (iii) Maximum proposed injection pressure; (iv) Maximum proposed annular pressure; (v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream; (vi) Size of tubing and casing; and (vii) Tubing tensile, burst, and collapse strengths. **Discussion:** This discussion in part 2.7 of the Guidance seems a little disjointed and becomes confusing. The initial statement quoted in the first column to the left appears to relate broadly to well construction, but the provision cited and paraphrased relates only to tubing and packer materials and placement. Then, the paragraph following the listing of the information also appears to relate to tubing and packer until it gets to the last sentence. That sentence, after an introductory reference to tubing and packer, unexpectedly shifts to discussing what appears to be placement of the well itself rather than the packer: "the UIC Program Director will either approve the proposed Class VI injection well location or require a different location to be characterized and proposed as a GS project site." This does not make sense and should be revised. To close out the thought more appropriately, the sentence should end by discussing packer depth placement.	To address this comment, EPA added language to the section to clarify the requirement.
52	**Texas RRC**	Page 23, first paragraph, second sentence. The RRC recommends the following revisions: "Ideally the packer will be placed within 100 feet above the perforations and within a cemented interval [~~with the confining layer~~].	EPA notes that the Guidance does not specify 100 feet because such a recommendation may not be appropriate on a national level. To address this comment, EPA changed the section to read as follows: "The UIC Program Director should compare the proposed depth of setting of the packer to all submitted site characterization information to ensure that the packer is set within an approved cemented interval. EPA recommends that the specific location of the packer be determined

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			based on a consideration of site-specific circumstances, such as how the packer will affect cement logging, plume tracking tools, planned mechanical integrity tests, and well component stresses."
53	**CSC**	**Guidance Statement:** Ideally the packer will be placed with the confining layer. **Recommended Revision:** ~~Ideally~~ Generally, the packer ~~will~~ should be placed ~~with~~ near the top of the confining layer, recognizing that this approach may need to be modified based on well-specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment. **Discussion:** Well logging of the confining zone can be affected by packer placement. Therefore, to obtain the best measurement of the quality of the cement through the confining layer as possible, while not creating unnecessary risks, EPA could recommend placing the packer near the top of the confining layer to obtain the best results, recognizing that this approach may need to be modified based on well-specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment. In every case, the operator should have the option to set the packer optimally with respect to well and local conditions. For example, if there is a very thick injection zone (hundreds of feet), the GS project could first inject into a lower portion of that zone. In that case, there may be a technical advantage to setting the packer deeper, rather than several hundred feet high to have it across the confining zone. It is difficult to foresee all the possible variables and possibilities, so flexibility in where the packer goes in order to allow adaptation to the site specific conditions will be an advantage for everyone.	To address this comment, EPA changed the section to read as follows: "The UIC Program Director should compare the proposed depth of setting of the packer to all submitted site characterization information to ensure that the packer is set within an approved cemented interval. EPA recommends that the specific location of the packer be determined based on a consideration of site-specific circumstances, such as how the packer will affect cement logging, plume tracking tools, planned mechanical integrity tests, and well component stresses."
54	**Texas RRC**	Page 23, first paragraph, fourth sentence: Because logging of the confining zone should occur in an openhole environment before casing is run, or in cased hole without the tubing, the RRC requests clarification of the following sentence: "If the packer is placed in the injection zone, logging of the confining layer may be more difficult."	To address this comment, EPA changed the section to read as follows: "The UIC Program Director should compare the proposed depth of setting of the packer to all submitted site characterization information to ensure that the packer is set within an approved cemented interval. EPA recommends that the specific location of the packer be determined based on a consideration of site-specific

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			circumstances, such as how the packer will affect cement logging, plume tracking tools, planned mechanical integrity tests, and well component stresses."
55	**CSC**	**Guidance Statement:** If any of the above information changes due to additional information gained during the drilling of the well and the subsequent required logging and data analysis before operation commences, the revised information about the tubing and packer materials to be used in Class VI injection well construction must be submitted to the UIC Program Director prior to operation of the injection well [§146.82(c)(5)]. **Final Rule Language:** 146.82(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information: * * * (5) Final injection well construction procedures that meet the requirements of §146.86; **Recommended Revision:** If any of the [~~above~~] information <u>used by the Director to determine and specify requirements for tubing and packer</u> changes [~~due to additional information gained~~] during the drilling <u>and construction</u> of the well[~~and the subsequent required logging and data analysis before operation commences~~], the revised information [~~about the tubing and packer materials to be used in Class VI injection well construction~~] must be submitted to the UIC Program Director prior to operation of the injection well [§146.82(c)(5)]. **Discussion:** This statement is not supportable by reference to §146.82(c)(5). The statement appears to use an amalgam of provisions in 146.82(c), not all of which have any bearing on tubing and packer specifications. The proposed revision is simpler and consistent with the need to review actual construction procedures and specifications to be sure that determinations about tubing and packer are still appropriate.	To address this comment, EPA changed the statement to clarify the rule requirements as follows: "If drilling, construction, and logging of the well reveal any changes to information used by the UIC Program Director to determine and specify requirements for tubing and packer , the revised information must be submitted to the UIC Program Director prior to operation of the injection well [40 CFR 146.82(c)(2), 40 CFR 146.82(c)(5)]."
2.8.1 Surface Safety Systems			
56	**Texas RRC**	Page 24, first paragraph, next to last sentence. The RRC recommends the following revisions: "Surface valves are typically <u>connected</u> [~~hooked~~] to a SCADA or other similar system that monitors variables such as pressure, temperature, and flow."	EPA updated the Guidance to reflect the commenter's suggested change.
2.8.3 Shut-off Information to Submit to the UIC Program Director with a Class VI Injection Well Permit Application			
57	**CSC**	**Guidance Statement:** The owner or operator must report the type and location of the safety valve(s) and any landing nipples as part of the construction plans and procedures submitted with the permit application [§§146.82(a)(11) and	To address this comment, EPA changed the statement to clarify the rule requirements; it now reads as follows: "The owner or operator must

#	Commenter	Comment	EPA Response
		146.82(a)(12)]. **Final Rule Provisions:** 146.82(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: * * * (11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well; (12) Injection well construction procedures that meet the requirements of §146.86; **Recommended Revision:** The owner or operator must ~~report~~ submit schematics or other appropriate drawings of the surface and subsurface construction details of the well [§§146.82(a)(11)], which should include the type and location of safety valve(s) and any landing nipples a~~s part of the construction plans and procedures submitted with the permit application [§§146.82(a)(11) and 146.82(a)(12)].~~ **Discussion:** The statement as it currently appears in the Guidance is not an accurate restatement of the rule requirements. It should be revised to make the proper distinction between what is required and what is offered as guidance	submit, with the permit application, schematics and other appropriate drawings of the surface and subsurface construction details of the well [40 CFR 146.82(a)(11) and 146.82(a)(12)], these schematics should include the type and location of the safety valve(s) and any landing nipples, if used.”
58	**Texas RRC**	Page 25, second complete paragraph, first sentence:. The RRC recommends the following revisions: “The UIC Program Director will review the type of shut-off system proposed and evaluate its utility [~~appropriateness~~] for the proposed well.”	To address this comment, EPA changed the sentence to read as follows: “The UIC Program Director should review the type of shut-off system proposed and evaluate its utility and appropriateness for the proposed well.”

Comments on Chapter 3

#	Commenter	Comment	EPA Response
3.1 Injection Pressure Requirement			
1	**CSC**	**Guidance Statement:** The GS Rule requires that the injection pressure may not exceed 90 percent of the injection zone fracture pressure except during stimulation [§146.88(a)]. **Final Rule Provisions:** 146.88(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. **Recommended Revision:** We are concerned about three aspects of proposed section 146.88(a), governing injection pressure limitations. First, it "restricts" fractures in the injection zone "except during stimulation" rather than focusing on maintaining the integrity of the confining zone, which is what really matters for protecting USDWs. Second, it fails to refer specifically to the full range of potential geomechanical failure modes potentially posed by operations at a particular site. Third, the type of geomechanical risk that is addressed (initiation or propagation of fractures), is dealt with in a potentially arbitrary fashion (the 90% of fracture pressure limit), which may not be appropriate in all cases. Our recommended language addresses these concerns by focusing on maintaining the integrity of the confining zone and including tensile failure and shear failure as transmissivity concerns. It calls for additional geomechanical studies of tensile failure and shear failure only "where appropriate" because there will be locations where experience or existing information will provide sufficient evidence to avoid the need for additional studies. The need for conducting additional tests and for determining which tests would be acceptable is left to the Director's discretion. ~~The GS Rule requires that the injection pressure may not exceed 90 percent of the injection zone fracture pressure except during stimulation [§146.88(a)].~~	EPA clarifies that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. The requirement may be reviewed at the six year review if field data show that a change is necessary.

#	Commenter	Comment	EPA Response
		The owner or operator must comply with a maximum injection pressure limit approved by the Director and specified in the permit. In approving a maximum injection pressure limit, the Director shall consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The Director shall approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise nontransmissive faults transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection or formation fluids in a manner prohibited by 40 CFR Part 144.12(a). **Discussion:** We continue to believe that this limitation on injection pressure is misguided and should be modified to adopt the recommendation of the Multi-Stakeholder Discussion participants (repeated in the column to the left).	
2	**CSC**	**Guidance Statement**: Maintaining the injection pressure below 90 percent of the injection zone fracture pressure prevents the injection from fracturing the confining layer and allowing fluids to leak out of the injection zone. **Discussion:** This statement might not be valid always, because the overlying layers can have a higher fracture pressure than the injection horizon.	To address this comment, EPA clarified in the Guidance that this is a conservative assumption.
3	**CSC**	**Guidance Statement**: The modeled pressures can be confirmed using sensors such as tiltmeters and microseismic monitoring to monitor and refine the model; however, these technologies are still experimental. **Discussion:** Microseismic monitoring techniques might not be applicable everywhere.	To address this comment, EPA clarified in the Guidance that these technologies are not universally applicable.
4	**AEP**	Page 26. 4th paragraph, first sentence: The microseismic technique might not be applicable everywhere.	To address this comment, EPA clarified in the Guidance that these technologies are not universally applicable.
5	**AEP**	Page 26, third paragraph, first sentence. This statement may not be valid at all times because the overlying layers can have a higher fracture pressure than the injection horizon.	EPA notes that this requirement was supported by State regulators. It may be reviewed at the six year review of the Class VI Rule if field data show that a change is necessary. To address this comment, EPA clarified in the Guidance that this is a conservative assumption.
3.2 Monitoring of the Annular Space			
6	**API**	The regulatory requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure (page 28) is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance

#	Commenter	Comment	EPA Response
		formation. EPA acknowledges that, in some circumstances, maintaining an annulus pressure greater than the injection pressure could result in a greater chance for damage to the well or the formation. As a result, the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation. However, it would be better if this flexibility was explicitly approved in the guidance document. EPA's reasoning assumes that the failure will occur in the long string tubing and when/if it occurs, the CO2 will be forced to stay in the tubing if the tubing-casing annulus pressure has a greater pressure. This could occur, however all possible failure modes of the well must be examined and their effect. In a tubing leak, once the tubing-casing annulus and tubing pressures equalize, the CO2 could easily flow into the annulus anyway. Likewise, if the packer fails, the packer fluid in the tubing-casing annulus will flow downward and into the formation. The CO2 in the wellbore would replace the packer fluid when it leaves the annulus. The nature of CO2 itself requires that the surface pressure be high to keep the CO2 supercritical and avoid phase changes in the tubing. This is different than injecting a dense fluid and the EPA requirement means an operator needs to have a pressure on the annulus at the top of the well that is significantly over formation fracture pressure and likely to be over the formation fracture pressure for the entire length of the well. The result of a casing leak with an annulus pressurized to this degree could inject packer fluid into formations, possibly including USDWs. Furthermore, applied casing pressure creates ballooning and will result in additional stress cycles on the cement sheath over the life of well. Stress cycles – due to periodically adding pressure over time - may debond the cement interfaces and induce fractures in the matrix. Wellhead injection pressure is likely to be at least 1200 psi for a CO2 injector which could require approximately 1500 psi applied casing annulus pressure. Jackson, et al, 1996, indicate a change in diameter of 0.003 inches is sufficient to create a microannulus leakage pathway. Applied casing pressure of 1500 psi with a packer fluid of 8.6 ppg density in a 7", 26 ppf casing may create up to 0.0034 inches based on API 10TR, Cement Sheath Evaluation, 2007, assuming normal pore pressure conditions. This means that operating with a higher pressure on the annulus and the ballooning effect associated with periodically adding pressure may over time reduce the cement bonding between the long-string and the cement behind the long string. Additionally, API Recommended Practice (RP) 90 (adopted by BOEMRE at 30 CFR Part 250 "Annular Casing Pressure Management for Offshore Wells", 2010) has a warning against applying an	comment period. EPA clarifies that the intent of the Class VI Rule is that the well should be designed with sufficient safety margins that a pressure above that of the injection pressure would not damage the well or the formation. To address this comment, EPA added language to indicate that the Director may modify the annulus pressure limit, as allowed in the rule.

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		annular pressure that can damage the well integrity, i.e., cement sealing performance. In effect, the EPA guidance violates this federal rule. The integrity damage warning (cement stress cracking) appears in the following sections: 1. 5.4.6 Subsequent Bleed-down and Build-up Tests (p.15,) 2. 7.5.7 Subsequent Annular Pressure Evaluation Tests (p.29) 3. 14.1.4 Cementing Program (p.83) In addition, RP 90 says operator-induced pressures during injection operations can contribute to the above stress loads (14.1.1 Casing Design, p.82, 2nd paragraph and 3rd bullet where "injected fluids" could represent applied pressure to the annulus). API recommends EPA include in its Guidance a more common and safe practice of maintaining a positive pressure of 200-250 psi which is not detrimental to the integrity of the wellbore. This gives the operator an ability to monitor the integrity of the outer most casing. A continuous positive pressure with slight fluctuations due to temperature variations indicates that the longstring integrity is secure. Also, the lack of similar magnitude injection pressure in the tubingcasing annulus indicates that the tubing and packer are functioning as designed. An operator's focus should be on monitoring the annulus pressure and liquid height as this will tell them how effectively the casing, tubing and packing are holding. References: Jackson, P.B., Murphey, C.E., 1993, *Effect of Casing Pressure on Gas Flow Through a Sheath of Set Cement*, SPE #25698, SPE/IADC Drilling Conference, Amsterdam API Technical Report 10, *Cement Sheath Evaluation*, 2007	
7	**CSC**	We also agree with API that "[t]he regulatory requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure (page 28) is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection formation." This is another point on which MSD participants were able to achieve consensus as reflected in the May 15, 2009 MSD Recommendations (copy attached). Although the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation, it would be better if this flexibility is explicitly acknowledged, and its application explained in the final Guidance.	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. EPA clarifies that the intent of the Class VI Rule is that the well should be designed with sufficient safety margins that a pressure above that of the injection pressure would not damage the well or the formation. To address this comment, EPA added language to indicate that the Director may modify the annulus

#	Commenter	Comment	EPA Response
			pressure limit, as allowed in the rule.
8	**Texas RRC**	Page 27, first paragraph, first sentence. The RRC recommends the following revisions: "Unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs, the [~~The~~] GS Rule requires that annular pressure between the tubing and the casing be maintained higher than the injection pressure. The rule also requires [~~and~~] that the annulus be filled with a non-corrosive fluid [§146.88(c)]."	To address this comment, EPA changed the sentence to read as follows, "The Class VI Rule requires that the annulus be filled with a non-corrosive fluid and that the annular pressure between the tubing and the casing be maintained at a pressure higher than the injection pressure, unless the UIC Program Director determines that this requirement might harm the integrity of the well or endanger USDWs [40 CFR 146.88(c)]."
9	**NACCSA**	The guidance repeats the provision of the final Class VI rule that the annular pressure between the tubing and the casing be maintained higher than the injection pressure (EPA 816-D-10-008, p. 27). The rule includes the additional caveat: "…unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs" (40C.F.R. 146.88(c)). The guidance writes this caveat out of the rule. Flexibility regarding annular pressure requirements is important, as higher annular pressure may cause stresses that increase relevant risks in a specific case. [FN 26] FN 26: Hypothetically, under the final Class VI rule, it is conceivable that the bottom hole annular pressure could exceed the relevant fracking pressure.	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. EPA clarifies that the intent of the Class VI rule is that the well should be designed with sufficient safety margins that a pressure above that of the injection pressure would not damage the well or the formation. To address this comment, EPA has revised the section to clarify the Director's involvement, including exercising Director's discretion.
10	**C12**	**Annular Pressure (Section 3.2)** **Discussion** The Guidance notes regarding annulus pressure: The GS Rule requires that annular pressure between the tubing and the casing be maintained higher than the injection pressure and that the annulus be filled with a non-corrosive fluid [§146.88(c)].8 The Guidance explains the rationale as follows: This requirement provides a continuous check on the integrity of the well. If holes develop either in the casing, tubing, or packer the pressure and fluid volume in the annulus will begin to change. In addition, if the pressure in the annulus is higher than the injection pressure, any leak in the tubing will not	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. EPA clarifies that the intent of the Class VI rule is that the well should be designed with sufficient safety margins that a pressure above that of the injection pressure would not damage the well or the formation. To address this comment, EPA added language to indicate that the Director may modify the annulus pressure limit, as allowed in the rule.

#	Commenter	Comment	EPA Response
		result in fluid escaping. Instead fluid from the annulus will flow into the tubing. Using a non-corrosive fluid in the annular space prevents corrosion of the tubing or casing by the annular fluid. 9 We are concerned that maintaining annular pressure higher than the operating injection pressure may endanger a USDW. Consider for instance a situation where CO2 is to be injected at a depth of some 1200 m into a reservoir with initial pressure equal to hydrostatic pressure, i.e. ~ 120 bar. If one injects CO2 at 152 bar (downhole pressure), this CO2 needs to be close to 80 bar at the surface. 10 Consequently, the annular pressure needs to be at least 80 bar near the surface (to satisfy the intent of the GS Rule), or even greater than 152 bar (in the strictest interpretation of the GS Rule). A pressure of 80 bar near the surface is clearly well above the fracture pressure. In fact, with 80 bar at surface, the pressure in the annulus is higher than fracture pressure down to a depth of 1000 m.11 Consequently, any leak in the casing will not simply be detected by a drop in annular pressure, it will also generate a fracture, potentially endangering USDW. **Necessary Changes** The UIC Rules state that: The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, <u>unless the Director determines that such requirement might harm the integrity of the well or endanger a USDW.</u>12 The Guidance should be revised to recognize the potential for annulus pressures greater than injection pressures to endanger USDWS, and should authorize the Director to deviate from this requirement if "such requirement might harm the integrity of the well or endanger a USDW" as provided for in the UIC Rules. 8 Well Construction Guidance, p. 27. 9 Well Construction Guidance, p. 27. 0The injection pressure of 152 bar is an assumed number to simplify the arithmetic. Assume for simplicity that the CO2 density is 600 kg/m3, so that it builds 72 bar of hydrostatic pressure in a well of 1200 m depth. Since the bottom hole pressure needs to be 152 bar, surface pressure must be (152 – 72) = 80 bar.	

#	Commenter	Comment	EPA Response
		11 Assuming that fracture pressure (PF) is 80% over hydrostatic pressure (PH), and that PH = 104 d (d in meters, PH in Pascals), then PF = 1.8 x 104 d. The pressure in the annulus (PA) also rises hydrostatically, starting from 80 bar, i.e. PA = 8 x 106 + 104 d (d in meters, density of annulus fluid assumed to be the same as the density of water), so PA = PF when d = (8 x 106)/(0.8 x 104) = 1000 m. 12 40 CFR §146.88(c) (emphasis added).	
11	**API**	The regulatory requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure (page 28) is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection formation. EPA acknowledges that, in some circumstances, maintaining an annulus pressure greater than the injection pressure could result in a greater chance for damage to the well or the formation. As a result, the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation. However, it would be better if this flexibility was explicitly approved in the guidance document. EPA's reasoning assumes that the failure will occur in the long string tubing and when/if it occurs, the CO_2 will be forced to stay in the tubing if the tubing-casing annulus pressure has a greater pressure. This could occur, however all possible failure modes of the well must be examined and their effect. In a tubing leak, once the tubing-casing annulus and tubing pressures equalize, the CO_2 could easily flow into the annulus anyway. Likewise, if the packer fails, the packer fluid in the tubing-casing annulus will flow downward and into the formation. The CO_2 in the wellbore would replace the packer fluid when it leaves the annulus. The nature of CO_2 itself requires that the surface pressure be high to keep the CO_2 supercritical and avoid phase changes in the tubing. This is different than injecting a dense fluid and the EPA requirement means an operator needs to have a pressure on the annulus at the top of the well that is significantly over formation fracture pressure and likely to be over the formation fracture pressure for the entire length of the well. The result of a casing leak with an annulus pressurized to this degree could inject packer fluid into formations, possibly including USDWs. Furthermore, applied casing pressure creates ballooning and will result in additional stress cycles on the cement sheath over the life of well. Stress cycles – due to periodically adding pressure over time - may debond the cement interfaces and induce fractures in the matrix. Wellhead injection pressure is likely to be at least 1200 psi for a CO_2 injector which could require approximately 1500 psi applied casing annulus pressure. Jackson, et al,	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. EPA clarifies that the intent of the Class VI rule is that the well should be designed with sufficient safety margins that a pressure above that of the injection pressure would not damage the well or the formation. To address this comment, EPA added language to indicate that the Director may modify the annulus pressure limit, as allowed in the rule.

#	Commenter	Comment	EPA Response
		1996, indicate a change in diameter of 0.003 inches is sufficient to create a microannulus leakage pathway. Applied casing pressure of 1500 psi with a packer fluid of 8.6 ppg density in a 7", 26 ppf casing may create up to 0.0034 inches based on API 10TR, Cement Sheath Evaluation, 2007, assuming normal pore pressure conditions. This means that operating with a higher pressure on the annulus and the ballooning effect associated with periodically adding pressure may over time reduce the cement bonding between the long-string and the cement behind the long string. Additionally, API Recommended Practice (RP) 90 (adopted by BOEMRE at 30 CFR Part 250 "Annular Casing Pressure Management for Offshore Wells", 2010) has a warning against applying an annular pressure that can damage the well integrity, i.e., cement sealing performance. In effect, the EPA guidance violates this federal rule. The integrity damage warning (cement stress cracking) appears in the following sections: 1. 5.4.6 Subsequent Bleed-down and Build-up Tests (p.15,) 2. 7.5.7 Subsequent Annular Pressure Evaluation Tests (p.29) 3. 14.1.4 Cementing Program (p.83) In addition, RP 90 says operator-induced pressures during injection operations can contribute to the above stress loads (14.1.1 Casing Design, p.82, 2nd paragraph and 3rd bullet where "injected fluids" could represent applied pressure to the annulus). API recommends EPA include in its Guidance a more common and safe practice of maintaining a positive pressure of 200-250 psi which is not detrimental to the integrity of the wellbore. This gives the operator an ability to monitor the integrity of the outer most casing. A continuous positive pressure with slight fluctuations due to temperature variations indicates that the longstring integrity is secure. Also, the lack of similar magnitude injection pressure in the tubingcasing annulus indicates that the tubing and packer are functioning as designed. An operator's focus should be on monitoring the annulus pressure and liquid height as this will tell them how effectively the casing, tubing and packing are holding. References: Jackson, P.B., Murphey, C.E., 1993, *Effect of Casing Pressure on Gas Flow Through a Sheath of Set Cement*, SPE #25698, SPE/IADC Drilling Conference, Amsterdam API Technical Report 10, *Cement Sheath Evaluation*, 2007	
12	**CSC**	We also agree with API that "[t]he regulatory requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance

#	Commenter	Comment	EPA Response
		(page 28) is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection formation." This is another point on which MSD participants were able to achieve consensus as reflected in the May 15, 2009 MSD Recommendations (copy attached). Although the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation, it would be better if this flexibility is explicitly acknowledged, and its application explained in the final Guidance.	comment period. EPA clarifies that the intent of the Class VI rule is that the well should be designed with sufficient safety margins that a pressure above that of the injection pressure would not damage the well or the formation. To address this comment, EPA added language to indicate that the Director may modify the annulus pressure limit, as allowed in the rule.
13	**CSC**	**Guidance Statement:** The installation and use of continuous recording devices to monitor various pressure and volumes, as well as injection rates is also required [§146.88(e)(1)]. **Discussion:** The Guidance should provide a clear indication that digital recording devices are considered to meet the requirement to be "continuous" even thought they capture information on an interrupted basis.	EPA notes that this topic is discussed in the Testing and Monitoring Guidance.

Comments on Chapter 4

#	Commenter	Comment	EPA Response
4 Conclusions			
1	**Texas RRC**	Page 28, second paragraph, first sentence: The RRC recommends the following revisions: "At least two casing strings [~~casings~~] are used in the construction of a Class VI injection well."	EPA updated the Guidance to reflect the commenter's suggested change.
2	**API**	The requirement for the *long-string* to be cemented to surface in every situation should be modified. Consistent with Section 2.5.1 of the Guidance allowing alternatives if cementing to the surface cannot be done, the statement on page28 should read "long-string should be cemented to the surface if possible". The issue is that it isn't always possible to circulate cement to surface for various reasons. Staging cement jobs to step the level of the cement to the surface with two or more jobs is common practice when it is known or suspected that it will be difficult or impossible to circulate cement to surface in one attempt. Multiple staging jobs to position cement behind the long-string can be planned when/where necessary but success is never guaranteed. Subsequent perforating and cement-squeeze jobs can also be used to attempt to circulate cement to surface but again, there are no guarantees. Therefore, "if possible" should be added to the requirement.	To address this comment, EPA has added language to indicate that staging is allowed.
3	**CSC**	**Guidance Statement:** The surface casing must extend through the base of the lowermost USDW and be cemented to the surface [§146.86(b)(2)]. **Final Rule Provisions:** 146.86(b) (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. **Recommended Revision:** ~~The~~ 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. [§146.86(b)(2)]. Dropping the use of "the" in front of "surface casing" will help to avoid misleading. **Discussion:** The following more correct statement appears on page 14 of the draft Guidance: "The GS Rule requires that the surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of single or multiple strings of casing and stages of cement [§146.86(b)(2)]."	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. The rule language requires circulation of cement to the surface. To address this comment, EPA added discussion of where Director's discretion is provided if cement cannot be circulated to the surface. EPA also added discussion of cement top-off in other sections of the document.
4	**CSC**	**Guidance Statement: pg 27:** The GS Rule requires that annular pressure between the tubing and the casing be maintained higher than the injection pressure and that the annulus be filled with a non-corrosive fluid [§146.88(c)].	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period.

#	Commenter	Comment	EPA Response
		pg 28: This annular space must be filled with a non-corrosive fluid approved by the UIC Program Director and the owner or operator must maintain a pressure on the annulus greater than the operating injection pressure, unless the UIC Program Director determines that such pressure requirements could harm the integrity of the well or endanger USDWs [§146.88(c)]. **Final Rule Language:** 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 or endanger USDWs. **Recommended Revision:** We also reiterate our view that the wording of the final rule is itself problematic. That is why the Multi- Stakeholder Discussion participants made the following recommendation: Agency and industry experience with the Class II UIC program does not support a requirement to "maintain on the annulus a pressure that exceeds the operating injection pressure." The standard proposed by EPA is consistent with neither the risk level related to CO2 nor the specifications needed to monitor the annular space for leakage. We suggest revising section 146.88(c) to read: "(c) The owner or operator must fill the annulus between the tubing and the long string casing with a ~~non-corrosive~~ corrosion inhibiting 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~~ a positive pressure on the annulus." **Discussion:** We support the comments of API regarding the regulatory requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure, which is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection formation. EPA acknowledges that, in some circumstances, maintaining an annulus pressure greater than the injection pressure could result in a greater chance for damage to the well or the formation. As a result, the final rule provides the Director discretion to adjust	EPA clarifies that the intent of the Class VI rule is that the well should be designed with sufficient safety margins that a pressure above that of the injection pressure would not damage the well or the formation. To address this comment, EPA has clarified in the Guidance that the Director may allow a lower annulus pressure.

#	Commenter	Comment	EPA Response
		this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation. However, it would be better if this flexibility was explicitly approved in the guidance document. EPA's reasoning assumes that the failure will occur in the long string tubing and when/if it occurs, the CO2 will be forced to stay in the tubing if the tubing-casing annulus pressure has a greater pressure. This could occur, however all possible failure modes of the well must be examined and their effect. In a tubing leak, once the tubing-casing annulus and tubing pressures equalize, the CO2 could easily flow into the annulus anyway. Likewise, if the packer fails, the packer fluid in the tubing-casing annulus will flow downward and into the formation. The CO2 in the wellbore would replace the packer fluid when it leaves the annulus. The nature of CO2 itself requires that the surface pressure be high to keep the CO2 supercritical and avoid phase changes in the tubing. This is different than injecting a dense fluid and the EPA requirement means an operator needs to have a pressure on the annulus at the top of the well that is significantly over formation fracture pressure and likely to be over the formation fracture pressure for the entire length of the well. The result of a casing leak with an annulus pressurized to this degree would be an uncontrolled fracture of the surrounding formation and injection of the packer fluid into the formation. As the packer fluid is likely to be a stabilized brine, this could lead to a brine injection into a USDW. Furthermore, applied casing pressure creates ballooning and will result in additional stress cycles on the cement sheath over the life of well. Stress cycles – due to periodically adding pressure over time – may debond the cement interfaces and induce fractures in the matrix. Wellhead injection pressure is likely to be at least 1200 psi for a CO2 injector which could require approximately 1500 psi applied casing annulus pressure. Jackson, et al, 1996, indicate a change in diameter of 0.003 inches is sufficient to create a microannulus leakage pathway. Applied casing pressure of 1500 psi with a packer fluid of 8.6 ppg density in a 7", 26 ppf casing may create up to 0.0034 inches based on API 10TR, Cement Sheath Evaluation, 2007, assuming normal pore pressure conditions. This means that operating with a higher pressure on the annulus and the ballooning effect associated with periodically adding pressure may over time reduce the cement bonding between the long-string and the cement behind the long string.	

#	Commenter	Comment	EPA Response
5	**CSC**	**Guidance Statement:** The long-string casing extends to the injection zone and must also be cemented to the surface [§146.86(b)(3)]. **Final Rule Language:** The long-string casing extends to the injection zone and must also be cemented to the surface [§146.86(b)(3)]. **Recommended Revision:** As noted by API in the comments reproduced in the column to the right, this requirement is problematic. We also reiterate the comments on this issue and the recommendation of the Multi- Stakeholder Discussion participants: EPA's proposed §146.86(b)(3) would require the long string casing to be cemented by circulating cement to surface in one or more stages. Yet that may be hard to accomplish in some cases, such as very deep wells. There are also potential disadvantages of this approach with regard to the weight of the cement column and its relation to well integrity. Sealing this annulus also eliminates an approach for monitoring the integrity of the cement in that critical interval through the primary confining interval and above. We recommend that EPA not make this a mandatory requirement. The requirement should also recognize that there may be other technologies that could be as effective as cement and centralizers, which may not be feasible in some applications; furthermore, current research and development efforts are likely to yield additional technologies the use of which should not be foreclosed. Accordingly, we recommend the following language for §146.86(b)(3): "(3) At least one long string casing, using a sufficient number of centralizers, which at a minimum: must be sealed from within the injection zone upward through the overlying confining zone, and must provide adequate isolation of the injection zone and other intervals as necessary for protection of USDWs using cement and/or other isolation techniques. The Director may approve the use of packers or alternative isolation techniques, provided these are demonstrated to be equivalent to cement or more effective to provide adequate isolation and to protect USDWs." MSD Letter of May 14, 2009 at 5. **Discussion:** We agree with the API recommendation for revision of the Guidance on this issue: The requirement for the *longstring* to be cemented to surface in every situation should be modified. Consistent with Section 2.5.1 of the Guidanceallowing alternatives if cementing to the surface cannot be done, the statement on page 28 should read "long-string should be cemented to the surface if possible". The issue is that it isn't always possible to circulate cement to surface for various reasons. Staging cement jobs to step the level of the cement to the surface with two or more jobs is common practice when it is	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. To address this comment, EPA added a discussion of how Director's discretion is allowable if cement cannot be circulated to the surface.

#	Commenter	Comment	EPA Response
		known or suspected that it will be difficult or impossible to circulate cement to surface in one attempt. Multiple staging jobs to position cement behind the long-string can be planned when/where necessary but success is never guaranteed. Subsequent perforating and cement-squeeze jobs can also be used to attempt to circulate cement to surface but again, there are no guarantees. Therefore, "if possible" should be added to the requirement.	
6	**CSC**	Second, we agree with the API recommendation for revision of the Guidance on the requirement for the long-string casing to be cemented to surface. Staging cement jobs to step the level of the cement to the surface with two or more jobs is common practice when it is known or suspected that it will be difficult or impossible to circulate cement to surface in one attempt. Multiple staging jobs to position cement behind the long-string can be planned when/where necessary but success is never guaranteed. Subsequent perforating and cement-squeeze jobs can also be used to attempt to circulate cement to surface but again, there are no guarantees. Therefore, "if possible" should be added to the requirement.	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. To address this comment, EPA added a discussion of how Director's discretion is allowable if cement cannot be circulated to the surface.
7	**CSC**	Third, we continue to support the much better alternative wording for the long string casing requirement presented by the Multi- Stakeholder Discussion participants in the MSD Recommendation letter of May 14, 2009 (copy attached).	EPA notes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. To address this comment, EPA added a discussion of how Director's discretion is allowable if cement cannot be circulated to the surface.
8	**CSC**	With respect to the injection pressure limitation, we continue to believe that limiting injection pressure to ninety percent of injection zone fracture pressure is misguided and should be modified to adopt the recommendation of the Multi-Stakeholder Discussion participants. The MSD participants expressed concern about three aspects of section 146.88(a). First, it "restricts" fractures in the injection zone "except during stimulation" rather than focusing on maintaining the integrity of the confining zone, which is what really matters for protecting USDWs. Second, it fails to refer specifically to the full range of potential geomechanical failure modes potentially posed by operations at a particular site. Third, the type of geomechanical risk that is addressed (initiation or propagation of fractures), is dealt with in a potentially arbitrary fashion (the 90% of fracture pressure limit), which may not be appropriate in all cases. The MSD recommendation addressed these concerns by focusing on maintaining the integrity of the confining zone and including tensile failure and	EPA notes that this threshold is a requirement of the Class VI Rule, and emphasizes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. As part of the six year review, EPA will review this item and if field data indicate a change is warranted a change may be made at that time.

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		shear failure as transmissivity concerns. It called for additional geomechanical studies of tensile failure and shear failure only "where appropriate" because there will be locations where experience or existing information will provide sufficient evidence to avoid the need for additional studies. The need for conducting additional tests and for determining which tests would be acceptable is left to the Director's discretion. Here is the recommended revision to section 146.88(a): The owner or operator must comply with a maximum injection pressure limit approved by the Director and specified in the permit. In approving a maximum injection pressure limit, the Director shall consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The Director shall approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection or formation fluids in a manner prohibited by 40 CFR Part 144.12(a).	
9	**API**	Page 28 states, "Injection pressure must **not exceed 90%** of fracture pressure of the injection zone" during injection operations. This limitation is unnecessary because the CO2 EOR industry has proven for decades that periodically exceeding fracture pressure of a permitted injection zone during the cycling of injection operations was safe. The ability of the permeable rock in the injection zone to fracture and confine the fracture within the designated injection zone is well known and understood. The nature of the caprock to resist fracturing at the controlled injection pressures during injection operations into the designated injection zone below the caprock is also well known and understood. Prudent operation in injection operations prohibits formation damage due to unnecessary or excessive injection pressures. Operators don't desire to operate with practices that will damage their operation, reduce safety and hurt them financially. At a minimum, the Guidance should add the phrase "at the perforation" to the requirement since the fracture pressure can vary vertically through the injection zone.	EPA notes that this threshold is a requirement of the Class VI Rule, and emphasizes that comments on the Class VI Rule are beyond the scope and intent of this Guidance comment period. As part of the six year review, EPA will review this item and if field data indicate a change is warranted a change will be made at that time.
10	**API**	The GS rule calls for operators to maintain mechanical integrity of the well "at all times" [§146.88(d)]. Although the intent of the EPA is to ensure that the operator is prudent with injection operations, it is possible a component will fail over the multi-decade life of a well and the operator should be charged with proactive issue identification and resolution. The Guidance should make clear	To address this comment, EPA has added language discussing what should be done in the event of a loss of mechanical integrity.

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		that operator should be tasked with putting a program in-place to monitor injection operations and to respond when a failure occurs to repair the failure and to regain any lost mechanical integrity. No operator can ensure mechanical integrity of a well at all times. All operators should ensure that a plan is in-place to minimize failures and to respond immediately when and if a failure does occur.	
11	**CSC**	**Guidance Statement**: The owner or operator must also maintain the mechanical integrity of the well at all times [§146.88(d)]. **Final Rule Language:** 146.88 (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. **Discussion** : Although the intent is to ensure that the operator is prudent with injection operations, it is possible a component will fail over the multi-decade life of a well and the operator should be charged with proactive failure identification and resolution. The Guidance should make clear that operator is tasked with putting a program in place to monitor injection operations, to respond immediately when a failure is discovered, to repair the failure and to regain any lost mechanical integrity. No operator can maintain mechanical integrity of a well at all times. All operators should ensure that a plan is in-place to minimize failures and to respond immediately when and if a failure does occur.	To address this comment, EPA has added language discussing what should be done in the event of a loss of mechanical integrity.

Comments on Chapter 5

#	Commenter	Comment	EPA Response
5 References			
1	**API**	Jackson, P.B., Murphey, C.E., 1993, *Effect of Casing Pressure on Gas Flow Through a Sheath of Set Cement*, SPE #25698, SPE/IADC Drilling Conference, Amsterdam API Technical Report 10, *Cement Sheath Evaluation*, 2007	EPA did not add these references to the Guidance; the references were only available for purchase.