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Thank you for the opportunity to participate in the development of California Air Resources Board's (ARB) "Climate Change Draft Scoping Plan" issued in June 2008. Shell recognizes and appreciates the significant effort undertaken by ARB staff to develop the Draft Scoping Plan.

Shell views carbon dioxide capture and storage (CCS) as an important element of a portfolio of technologies needed to reduce CO_2 emissions. Shell is committed to advancing CCS technologies globally and regionally. As such, Shell is prepared to work closely with CARB and all other stakeholders to develop a regulatory framework that would allow the development of commercial scale CCS projects in California before 2020.

In general, Shell believes Carbon Capture and Geologic Storage (CCS) is a technology that can assist in meeting AB32's 2020 emission reduction goals. Although capture of CO_2 from low purity sources is an area of ongoing development, CCS technology has been successfully applied to store approximately a million of tonnes of CO_2 per year in subsurface formations over a period of over ten years (Sleipner gas field in Norway).

In California, CCS technology presents an opportunity for achieving GHG emission reductions. According to preliminary estimates, California has 75 - 300 metric gigatons of CO_2 sequestration capacity in its saltwater rock formations. In addition, there are several industrial processes with high concentrations of CO_2 in process or exhaust streams that are potentially viable candidates for early application of CCS; examples include fermentation processes such as those used in ethanol production, older hydrogen plants in oil refineries and chemical plants, and natural gas processing facilities. (Reference: "Geologic Carbon Sequestration Strategies for California - Report to the Legislature - Final Staff Report," dated November 2007.) For these plants, where a high purity stream of CO_2 is produced as part of the industrial process, capture technologies are proven and available. It is our firm belief that it is technically feasible to implement CCS for such sources prior to 2020. While the cost of early projects would almost certainly be high, a regulatory framework that results in early deployment of CCS projects will accelerate technology development and promote cost reduction and economies of scale, and could eventually facilitate the development of a robust CCS industry for California.

Therefore, the Scoping Plan should include a section on CCS that:

1. Recognizes CCS as a mitigation option

2. Encourages and supports demonstration CCS projects in order to lay the foundation for commercial scale CCS projects

3. Commits the ARB to development of the regulatory framework and protocols for CCS, in the near term, and to encourage CCS advancement in a safe and environmentally sound manner that addresses:

    - Permitting (capture, transport, storage)
    - Monitoring, measuring, & verification protocols
    - Emissions accounting protocols
    - Long term responsibilities
    - Harmonization with future federal CCS guidelines

California should commit to developing this regulatory framework so that early CCS movers can begin to take steps to:

- Demonstrate storage technology without necessarily relying on development of capture technology of power plants
- Understand the concerns of the public and how to address them
- Test regulatory structure
- Begin developing infrastructure (i.e. pipelines & service companies)

We have attached specific language changes to the Draft Scoping Plan, and a one-page overview of CCS as a process for general background. In addition, to illustrate some of the significant progress that has already been made on several of the areas of concern, please find attached a report submitted by Shell as technical input to the EPA's CCS UIC draft rulemaking process. While this report represents Shell's comments on the Federal (UIC) requirements, Shell is committed to working together with California to work through any California specific issues relating to California's processes and regulatory regimes as well.

The ARB should consider utilizing Early Voluntary Action Policy to facilitate early development of CCS protocols. Many complex issues must be resolved in developing the CCS regulatory framework, including who will be the lead regulatory agency or agencies, accounting protocols, property rights, long term stewardship/liability, and guidelines for siting, monitoring and verification, etc. Shell believes that a taskforce consisting of the appropriate state, federal, and local agencies and public and business experts should be formed to advise on the development of the regulatory framework.

In order to realize these opportunities it is imperative that ARB and relevant stakeholders begin to work together now to develop the appropriate regulatory frameworks and protocols. Shell looks forward to contributing to such a task force or another forum that California chooses to utilize. We also would appreciate an opportunity to discuss in more detail the issues, concerns, and potential options for the framework.

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Enclosures

Add the following section on pg 71 of Draft Scoping Plan between existing Section E and F

New Section F:

Technology Advancement:

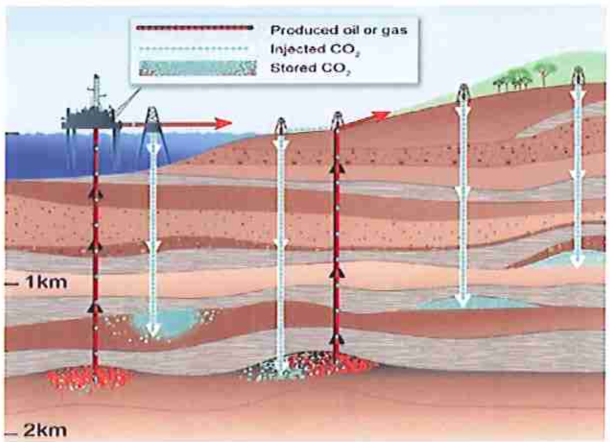
Carbon capture and storage (CCS) in geological formation is expected to play a significant role in meeting global GHG reductions. It is a potential opportunity for achieving GHG emission reductions in California, as well. California has many rock formations potentially suitable for geologic sequestrations and could provide large storage capacity. (Preliminary estimates in a report to the legislature, "Geologic Carbon Sequestration Strategies for California, Nov 2007", indicates 75 – 300 metric gigatons tons of CO_2 sequestration capacity in California.) All elements of CCS technology (CO_2 capture from man-made sources, transportation, and storage) exist today. However, commercial scale application of CCS requires technological readiness, economic viability and approriate regulatory frameworks.

California can play an important role in advancing this technology and the necessary policy frameworks, in a safe and environmentally sound manner. California's policies should encourage early demonstration and implementation of CCS in the near term, particularly from higher purity CO_2 sources that are more readily captured at lower costs. The appropriate regulatory framework needs further evaluation. ARB is committed to working with our state, local, federal, business, and public partners to develop the necessary regulatory frameworks and incentives to encourage CCS advancement in the near term.

Amend the following paragraph on pg C58 of the Draft Scoping Plan Appendices:

While the likely rate of deployment of CCS may not yield substantial reductions before 2020, CCS within California and the Western Electricity Coordinating Council (WECC) region has the potential to play a significant role in helping to achieve the GHG goals for 2050. To reduce emissions to the level needed by 2050, California needs to promote innovation and design a regulatory framework to produce significant improvement in technology and infrastructure. Furthermore, we must ensure that the policies ~~and technologies~~ are deployed over the next few years to allow ~~do not detract from~~ the implementation of this technology and even more promising technologies that emerge in the future.

Quick Guide to Carbon Dioxide Capture and Storage



Definition

Carbon Dioxide Capture and Storage (CCS) describes a set of technologies which can be used to collect carbon dioxide (CO_2) from industrial processes and power generation, separate and purify it, transport it to a storage site, compress it to a form suitable for storage and then place it in long term storage where it will remain indefinitely. Various forms have been conceived for permanent storage of CO_2. These forms include gaseous storage in various deep geological formations (including saline formations and exhausted gas fields), liquid storage in the ocean, and solid storage by reaction of CO_2 with metal oxides to produce stable carbonates.

Shell is principally interested in geological storage, although some work is taking place in the area of mineralization. The issue with the latter is the much smaller scale on which it operates. Shell is not working on ocean storage.

Potential Use

CCS is a technology typically imagined for coal-fired power generation. A 1 GW coal fired power station emits about 8 million tonnes of CO_2 per annum, for a total of 400 million tonnes of CO_2 in its 50-year life. The construction of coal-fired power generation is accelerating, with China and India in particular utilising this technology to support their rapid development. China is building some 50 GW of new coal-fired capacity each year (IEA World Energy Outlook 2007).

CCS applied to a modern conventional power plant could reduce CO_2 emissions to the atmosphere by approximately 80-90% compared to a plant without CCS. Capturing and compressing CO_2 requires energy and would increase the fuel needs of a plant with CCS by up to 20%.

CCS is also a technology of interest to the oil industry. Most refineries operate hydrogen-manufacturing facilities that vent nearly pure CO_2 to atmosphere as a waste product. This CO_2 could be captured and stored, thus lowering the CO_2 emissions of the refinery. Future refineries upgrading bitumen products from oil sands require even more hydrogen and often have substantial electricity generating facilities associated with them. These relatively higher emitting operations could use CCS to lower their overall emissions to levels comparable with conventional refining.

Longer term, CCS could play an important role in the transport sector. Two options are possible;

- If hydrogen becomes an important transport fuel, CCS would allow this fuel to be centrally manufactured from fossil sources without CO_2 emissions.
- If bio-fuels predominate, CCS could be used to store CO_2 emitted from the fermentation step in the process of ethanol manufacture, resulting in a net CO_2 removal from the atmosphere. Such a future strategy could even be important in addressing any overshoot in atmospheric CO_2 concentrations.

Why do we need CCS?

Almost all future pathways to a 450 - 550 ppm atmospheric concentration of CO_2 require CCS. Only a high nuclear scenario can reduce it. The World Business Council for Sustainable Development report "Pathways to 2050" showed that by 2050 some 1,000 large coal fired power plants could be in operation utilising CCS, with all new facilities using CCS from 2025.

The timing of CCS deployment is also critical. A study using the Shell World Energy Model that underpins our scenarios showed that each year we delay the widespread deployment of CCS beyond 2020 would translate into a 1-ppm increase in long-term atmospheric stabilization levels of CO_2. In other words, assuming deployment by 2020 can still result in a 450 ppm stabilization, then deployment by 2021 will mean that 451 ppm is the best we can achieve, and so on.

Capturing the CO_2

There are three types of CCS technology applied to coal-fired power generation;

- Post combustion – the flue gas from a coal-fired power station is stripped of its CO_2, which is then available for storage.
- Pre combustion – the coal is gasified rather than combusted, producing syngas (CO + H2). CO_2 can be easily recovered from syngas and is then available for storage.
- Oxyfuel combustion – this is a variation of post combustion, but the fuel is burned in oxygen instead of air, such that the flue gas consists mainly of carbon dioxide and water vapour.

Storing the CO_2

As CO_2 is pumped deep underground it is compressed by the higher pressures and becomes essentially a liquid, which then becomes trapped in the pore space between the grains of rock. Typically, an impermeable layer of cap-rock, such as shale, ensures that the CO_2 does not rise back to the surface. The presence of CO_2 in geological structures is a naturally occurring phenomenon. Occasionally CO_2 wells are drilled so that the CO_2 can be used for enhanced oil or gas recovery.

Over time, depending on the geology of the storage site, the CO_2 can react with the minerals in the rock, forming new minerals and providing increased storage security.

The Future of CCS

CCS is one of the few technologies that is entirely climate change driven, which means development and deployment will not happen without policy intervention.

A market price for CO_2 emissions, such as generated by the EU Emissions Trading System, is an effective deployment tool, but CCS must first be recognised as a valid mitigation technology by such systems. A legal framework must also exist to cover storage and long-term liability. Only the EU has proposed such recognition and the necessary framework.

Given that coal-fired power generation is growing rapidly in India and China, recognition of CCS as a valid emissions reduction technology under the Clean Development Mechanism (CDM) of the Kyoto Protocol is also a priority.

But CCS is at a difficult stage in its development. Whilst all the individual technologies making up a CCS plant are in operation somewhere for some reason, a single end-to-end plant (e.g. coal-fired power station with CCS) has yet to be built. Large-scale demonstration is now essential. This remains a pressing issue due to cost. The potential for delay is high.

Comments of Shell Exploration and Production Company
to the
United States Environmental Protection Agency
on Development of
Underground Injection Control Regulations for
Geologic Storage of Carbon Dioxide

I. Overview

A. Shell Exploration & Production Company (SEPCo) appreciates this opportunity to present the Environmental Protection Agency (EPA) with key information and considerations that could assist in EPA's development of proposed regulations for the underground injection of carbon dioxide (CO2) for geologic storage under the underground injection control (UIC) program of the Safe Drinking Water Act (SDWA).

B. SEPco recognizes that EPA will address some of the carbon capture and storage (CCS) issues in the body of the proposed rule while other issues likely will be addressed in the preamble to the proposed rule, with EPA inviting commenters to comment on whether or not these issues should be addressed in the body of the rule. SEPco plans to comment on the proposed rule and will decide the extent to which it makes sense to address additional issues at that time.

C. For now, SEPco's comments focus in particular on issues that will or, it believes should, be addressed in the provisions of the proposed rule. These issues relate primarily to the categories that have historically been included in UIC rules for the existing classifications of wells.

- Geologic Siting
- Area of Review
- Well Construction
- Mechanical Integrity Testing
- Operation and Monitoring
- Well Closure and Post-Closure Monitoring
- Public Participation

II. Threshold Issues that will define EPA's rulemaking approach

A. Statutory Authority

1. The Environmental Protection Agency (EPA) has authority under the Safe Drinking Water Act to regulate CO_2 geologic storage "to prevent underground injection which endangers drinking water sources." 42 USC §300h(b)(1). Specifically, the law provides "[u]nderground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons." 42 USC §300h(d)(2).

2. Accordingly, we suggest that any rules for geologic storage should be designed to prevent injection that would result in movement of fluid into an "underground source of drinking water" (USDW) as defined in the regulations (40 CFR §144.3) to the extent that such fluid carries contaminants into a USDW that would degrade the USDW to the point that a public water system supplied by that USDW could not comply with any national primary drinking water regulation that it otherwise would have been able to meet by treatment of the USDW absent degradation or to the extent that the presence of such contaminant in the USDW may otherwise adversely affect the health of persons.

3. Particularly when dealing with deep subsurface formations rather than near surface aquifers, we believe it is important to recognize that almost all lowermost USDWs would require extensive treatment to supply a public water system and that the potential for a fluid to endanger such a USDW must be assessed against that background and the baseline quality of the USDW. As EPA noted in one of its earliest discussions of this provision, "[i]n the case of [an] existing [public water] system using an underground water source, the logical meaning of this provision is that contamination endangers drinking water if it requires the use of new or additional treatment by the [public water] system to meet a national primary drinking water regulation or otherwise to prevent a health risk." 41 Fed. Reg. 36730, 36733 (Aug. 31, 1976). Similarly, EPA noted: "In the case of a potential source of underground water which will require treatment if it is used in the future, degradation may make further treatment necessary or may make the water unsuitable for use as drinking water. *Id.*

B. In developing this rule, SEPco recommends that EPA should propose provisions that will enable adaptation of the regulatory requirements based on lessons learned from geologic storage pilot and demonstration projects and from the early stages of rule implementation. Even with the evidence to date showing the safety and effectiveness of geologic storage, we think this is a very important step because there is still much that can be learned about the technologies and methodologies of geologic storage from projects that will be implemented in the US and in other parts of the world.

C. Geologic storage well classification issue

1. SEPco recommends that EPA should create a new well classification for geologic storage projects and wells outside of oil and gas reservoirs. Current well classifications are based on historical underground injection practices that existed in 1979. This did not include injection of CO2 for geologic storage, a methodology that introduces new practices and a range of new considerations. To account fully for these differences, it is our opinion that EPA should create a new class for CCS wells, probably Class VI.

2. For CO_2 injection into oil and gas reservoirs, SEPco recommends that EPA should retain Class II as the applicable classification but should create a new subclass for CO_2 storage projects and wells. Wells injecting into oil and gas reservoirs should be retained in Class II because there are many decisions about permitting and operation that will require consideration of factors relating to oil and gas production from those reservoirs. Although there has been much discussion of the notion of injecting into "depleted" oil and gas reservoirs for the purpose of geologic storage, it will prove difficult to establish the exact point at which an oil and gas reservoir is "depleted." Such decisions will always involve a combination of technical and economic assessments that will present a moving target. More importantly, it should not be necessary to make that decision at all. It is likely that injection into oil and gas reservoirs for storage would be combined with some degree of enhanced recovery of oil and/or gas. Accordingly, it will be appropriate to keep those decisions in the same part of the UIC program and with the same Director.

3. Creating a new Class II subclass for geologic storage will also facilitate decisions about primacy because the same agencies that exercise primacy over Class II programs will retain primacy and need only update their Class II programs to accommodate the new provisions for geologic storage. SEPCo believes that EPA should also allow such agencies to issue geologic storage permits for injection into formations other than oil and gas reservoirs when the geologic storage project will be co-located with injection into oil and gas reservoirs, especially when the project proposes to inject into multiple formations, including some portion of an oil and gas reservoir. EPA should avoid requirements for dual permitting and/or reviews by multiple agencies for storage projects. This approach will also facilitate retention of current EOR programs under current primacy agencies and in their present form without added requirements when geologic storage is not one of the objectives of the EOR project.

D. For purposes of regulating geologic storage, EPA should not categorize the CO_2 injectate as anything other than a "storage fluid" that is being regulated to prevent such injection from endangering USDWs. It may be best for EPA to define "storage fluid" as a new term to address this and avoid confusion with other types of injection such as Class I waste injection. By not classifying storage fluid as a waste or pollutant, this approach can also help to avoid unintended collateral effects from the potential application of other statutory and regulatory programs.

E. EPA should also avoid specifying content or constituent concentration requirements for fluids destined for geologic storage. Such requirements could unnecessarily restrict the ability to store fluids captured from specific greenhouse gas emission sources. The appropriate considerations are those relating to the compatibility of such fluids with any pipelines to be used for transportation, the tubular goods and materials of the injection wells, and the injection and confining zones with which the stored fluids might come into contact. Other requirements could arbitrarily constrain successful and beneficial applications of geologic storage technology.

F. Under the SDWA, States will be allowed to decide for themselves which agency to designate for enforcement of the geologic storage program under the new classification, as IOGCC has recommended.

G. In developing this proposed rule, we think that EPA should not attempt to require that permit applicants demonstrate that they have acquired any property rights for the injection zone. For now, EPA should retain the approach of its current UIC rules, providing that a permit "does not convey any property rights of any sort, or any exclusive privilege." Until EPA concludes that it has some authority to provide a means to assist permit applicants in acquiring any property rights, EPA should not presume that any such rights are even required.

If EPA concludes that it needs to address this issue any further, EPA can raise the issue in the preamble to the rule, announce the approach being taken for now, and then invite comment on whether EPA has the authority or any requirement to do more and, if so, what approach commenters recommend be taken.

III. Liability issues – who should hold liability during each project period, and how should status be defined:

A. The ways in which "liability issues" have sometimes been addressed has caused a considerable amount of confusion. Rather than combining these issues, we suggest they should be broken down into the component parts and addressed separately. Specifically, we think that EPA should differentiate among the following sets of issues:

1. Responsibility for management and monitoring during the operational life of a geologic storage project, including compliance with applicable regulatory requirements;

2. Liability for movement of stored fluids into unintended formations, during the operational life of a geologic storage project, when that fluid movement endangers or damages human health, environmental resources, mineral rights, or property rights;

3. Liability for releases of greenhouse gases, during the operational life of a geologic storage project, covered by storage credits;

4. Interim stewardship and management during post closure and before transference to a long-term caretaker;

5. Liability for movement of stored fluids into unintended formations during post closure and before transference to a long-term caretaker when that fluid movement endangers or damages human health, environmental resources, mineral rights, or property rights;

6. Liability for releases of greenhouse gases covered by storage credits during post closure, but before transference to a long-term caretaker;

7. Long-term stewardship and management after transference to a long-term caretaker;

8. Liability for movement of stored fluids into unintended formations after transference to a long-term caretaker when that fluid movement endangers or damages human health, environmental resources, mineral rights, or property rights;

9. Liability for releases of greenhouse gases covered by storage credits after transference to a long-term caretaker; and

10. Any other types of liability.

B. One significant group of issues often identified as a component of "long term liability" relates to the post-operational stewardship and management of the geologic storage project, facilities, and injection zones. It would be better and less confusing to identify this particular group of issues as "stewardship and management" rather than "liability." If the cessation of active injection operations is considered "closure," then that will be followed by a "post-closure" period during which the project operator should implement an approved post-closure monitoring, measurement and verification (MMV) program, and associated modeling, for a period sufficient to demonstrate to the applicable UIC Program Director that fluid movement resulting from the injection will not endanger USDWs.

C. The making of that demonstration should lead to transference of ownership and operation to a caretaker agency of the federal or state government for long-term post-transference stewardship and management, including any further MMV activities deemed appropriate or acceptable by the caretaker agency for any advancement of the scientific and technical knowledge and further understanding of the geologic storage project.

D. At this stage in the development of the regulatory framework for geologic storage, it is questionable whether EPA has the necessary authority to promulgate regulations providing for an agency to fulfill the caretaker role for the transference and post-transference steps in this process. Consequently, EPA should focus on the development of proposed regulations that will govern any necessary post-closure monitoring and provide financial assurance for the completion of well plugging, decommissioning of the project, and the completion of post-closure monitoring for a period sufficient to demonstrate that fluid movement resulting from the injection will not endanger USDWs.

IV. Issues that SEPCo believes should be addressed in the body of EPA's proposed rule

A. Geologic Siting

1. The factors that must be present for a site to qualify for geologic storage should be described generically with performance requirements that can be adapted to expanding knowledge about geologic storage in general, to the relative degree of knowledge about each site, and to the specific circumstances of each site.

2. The information to be submitted by a permit applicant in conjunction with a demonstration that injection will not endanger underground sources of drinking water (USDWs) should be focused wherever possible on information defined in terms of what needs to be demonstrated using "fit for purpose" information and methods rather than prescribed types of information and methods.

3. Applications should be considered on the basis of entire projects and should anticipate and authorize the use of area permits or generic specifications rather than require separate permitting for each individual well. EPA should view site characterization on a project basis so that the permitting of individual wells can be simplified or addressed in a manner similar to how area permits are issued for some oil fields.

4. Site characterization requirements should be designed to demonstrate that injection will not endanger USDWs because that is the standard of the SDWA.

5. More specifically, applicants should be required to demonstrate that the proposed project site has a geologic system comprised of:

    - An injection zone that will accept fluid proposed to be injected;

- A confining zone that is not compromised by known open faults or fractures within the area of review;

- A confining system sufficient to confine injected fluid and allow injection at proposed rates and volumes without reactivating faults or initiating or propagating fractures in the confining zone.

6. Applicants should not be required to prove the complete absence of any transecting, transmissive faults and fracture zones. Initial site characterizations should rely on the information available from reasonable site assessments, but projects can also rely on operational monitoring to indicate the presence of other features.

7. Applicants should be required to identify the geologic structure and hydrologic properties of the proposed site, designate the injection zone and the confining zone, and demonstrate the effectiveness of confinement, providing information which may include:

    - Geological names and Lithologic descriptions of the injection zone, confining zone(s), and interspersed formations;

    - Maps and cross sections of local geologic structure;

    - Tectonic seismic history showing the location, depth and magnitude of seismic events

8. In requiring this information, it should be made clear that:

    a. There is no requirement that 3D seismic be conducted for every site (or any site) to show plume geography or demonstrate non-endangerment.

    b. If faults transect the injection reservoir, applicants could provide data demonstrating that fault planes are non-transmissive.

9. In addition, applicants should be able to demonstrate confinement using "confining systems" that should be defined to include geologic formations and other means of limiting fluid movement above the injection zone. Such other means might include injection of material that would—through chemical transformations or other means—create barriers that serve to halt fluid movement to potential points or avenues of discharge from the injection zone.

10. Applicants should not be required to conduct detailed surveys of surface units above injection zones without some specific reason for doing so. It would be extremely onerous, for example, to require that applicants provide an up-to-date map of every house, business, or other structure

within an AOR that may exceed 100 square miles. This will constantly change during the 30 to 50-year life span of a major project. There is not sufficient value in the information to require that it be submitted.

11. Applicants could be required to characterize the overburden and subsurface structures in the injection and confining zones within the AOR based on:

- Data on the areal extent, thickness, porosity, and permeability of the injection zone and confining zone(s), including any geology/ facies changes, based on geologic cores, outcrop data, seismic surveys, well logs or other data acceptable to the Director;

- An estimation of the capacity of the injection zone using a methodology acceptable to the Director;

- Geomechanical information describing natural and induced fractures, stress, rock strength, and in-situ fluid pressures within the confining zone(s);

- Maps and cross sections illustrating regional geology, including the regional stress state.

12. Applicants should characterize USDWs by providing the geologic name, depth, maps and cross sections of all USDW's that may be affected by the injection. Applicants should assess chemical, geochemical, and hydrogeologic interactions to show compatibility of the injected fluid with the injection zone and the confining zone. It is not intended that the injected fluid will be compatible with all subsurface aquifers or USDWs. No assessment should be required to try to show this.

13. For USDW's that may be affected by the injection or are currently used by a public water system as sources of drinking water, and for any formation that is proposed to be used for monitoring, applicants should provide:

- Baseline fluid chemistry and geochemistry

- Baseline data on porosity, permeability, formation pressure, and specific storage or, a poroelastic parameter acceptable to the Director.

B. Area of Review

1. The AOR should be determined based on generally accepted and site relevant techniques, such as modeling, that define, in three dimensions, the maximum extent of the free phase CO_2 plume and associated pressure

front. Models should be selected to account for the buoyant nature and specific properties of separate phases of injected CO_2, and the multi-phase nature of fluids within the injection zone.

2. The requirement for this determination should be stated as a performance standard with maximum flexibility to use appropriate and cost-effective fit for purpose models.

3. The appropriate target for modeling is to demonstrate that the injection will not cause endangerment of any USDWs. That is the standard of the SDWA.

4. Moreover, there should be no requirement that applicants show exactly where the plume will be or what its size will be – only assess the maximum extent to show that injected fluid will not endanger any USDWs.

5. Applicants should be required to provide information on the AOR including:

    - Maps and cross sections

    - A description of each artificial penetration in the AOR that penetrates the confining zone, including active and abandoned wells

    - A demonstration that such artificial penetrations in the AOR will not provide avenues for endangerment of USDWs, which may include descriptions of the well or penetration type, construction, date drilled, location, depth, or record of plugging and/or completion.

6. As long as the applicant can provide acceptable evidence that an artificial penetration will not provide an avenue for endangering a USDW, there should not be any arbitrary minimum data requirement. Moreover, there should be some basis for concern that a particular penetration will be problematic before any demonstration is even required.

7. Thus, applicants should be required to review all available data on all abandoned wells in the AOR and assess whether they have been plugged in a manner that prevents the movement of fluid that endangers a USDW.

8. Applicants should be required to develop a "corrective action" plan to remediate artificial penetrations in the AOR, as necessary to prevent the movement of fluid that endangers a USDW.

9. The corrective action plan need not provide for immediate remediation of all artificial penetrations before injection is initiated as long as the plan will result in remediation of any problematic artificial penetration in advance of any potential for plume movement through that penetration.

C. Fluid Movement

1. Fluid movement should be limited only by the endangerment standard of the SDWA, which was intended to have two elements. It prevents movement of fluids into USDWs to the extent that fluid movement would (i) carry contaminants into the USDW (ii) with characteristics (e.g., concentration levels) that would cause a public water system using that USDW for source water to fail to comply with a national drinking water standard or would otherwise threaten public health.

2. Wells must be constructed, operated, maintained, converted, plugged, and abandoned in a manner that prevents the movement of fluid that endangers a USDW.

3. An "absolute fluid movement prohibition" approach should not be considered because it would impose an extremely difficult and ultimately unworkable standard that would preclude geologic storage projects in areas where lateral movement of fluids might potentially cross the USDW interface (i.e., the 10,000 ppm TDS isopleth).

4. Because many so-called USDWs (especially those falling in the 3,500 to 9,999 ppm TDS range) already contain so many "contaminants" that substantial treatment would be required under any circumstances for that USDW to be used as a drinking water source, the SDWA endangerment standard requires not only that there be contamination, but also that the contamination degrade the USDW to the point of requiring otherwise unforeseeable levels or types of treatment.

D. Well Construction

1. Surface Casing - The requirement should be that the well must be cased and cemented to prevent the movement of fluid that endangers a USDW. The long-string casing shall be cemented above the top of the injection zone and confining zone(s). Appropriate logs and other tests shall be conducted during the drilling and construction of new injection wells. A descriptive report interpreting the results of such logs and tests shall be prepared by a knowledgeable log analyst and submitted to the Director.

2. Casing, Cement, and Tubing – The requirements should be:

a. The casing and cement used in the construction of each newly drilled well shall be designed for the operating life expectancy of the well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

- Depth to the injection zone;
- Depth to the bottom of all USDWs
- Injection pressure, external pressure, internal pressure, and axial loading;
- Hole size;
- Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);
- Characteristics of injection fluid (chemical content, corrosiveness, and density);
- Lithology of injection and confining intervals; and
- Type or grade of cement

b. The tubing, completion, and annular fluid shall be designed for the expected service. In determining and specifying requirements for tubing, packer, or alternatives the following factors shall be considered:

- Depth of setting;
- Characteristics of injection fluid (chemical content, corrosiveness, and density);
- Injection pressure;
- Annular pressure;
- Rate, temperature and volume of injected fluid; and
- Size of casing.

3. If the tubing and packer alternative is used for completion of the well, injection shall be through tubing and packer that is set opposite a cemented interval of the long string casing above the uppermost

perforation or open hole for the injection zone at a depth acceptable to the Director.

E. Operation

1. Injection should be conducted such that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone. Fracturing within the injection zone should not be precluded so as to accommodate techniques that might be beneficial to enable or enhance geologic storage in certain formations.

2. The proposed rule should not adopt any prescriptive or fundamentally arbitrary limits on injection pressures. That determination should be made on a site-specific basis giving due consideration to the proposed injection fluids and characteristics of the sites.

3. There should not be any requirement that injection must be at a sufficient depth (i.e., at least 800 meters below the surface) so that the CO_2 remains in a supercritical state, not even to avoid mechanical integrity concerns associated with phase changes. Such an approach could preclude injection into some potentially usable oil and gas reservoirs. There is no reason to limit injection of CO_2 to the supercritical phase, and doing so could also limit injection into some saline formations that would otherwise be suitable for geologic storage. It is also possible that injection into some depleted oil and gas reservoirs at depths below 800 meters would not immediately result in supercritical phase because pressures have been reduced by production.

4. Throughout injection the operator should be required to monitor the injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long string casing at a frequency established in the permit, and to report the frequency and duration of any pressure gauge outages.

5. Operators could be required to equip injection wells with safety shutoff equipment designed to shut-in the well when pressures and flow rates or other parameters approved by the Director exceed a range and/or gradient specified in the permit.

6. EPA should not require the addition of an odorant or a tracer to the injected CO_2 to facilitate early detection of leaks or movement outside of the intended injection zone. The addition of an odorant would be impractical, without sufficient benefit, and potentially risky considering the depths at which storage will take place in most cases. Adding a tracer is also likely to be impractical and unnecessary, but is something that could be considered by an applicant for inclusion in a demonstration of

non-endangerment and/or in a MMV plan proposed in conjunction with a particular confining system.

7. Applicants should be required to submit a corrosion monitoring and prevention plan acceptable to the Director for permitted wells penetrating the confining zone.

F. Mechanical Integrity (MI)

1. Operators should be required to demonstrate mechanical integrity of injection wells using a method and at a frequency acceptable to the Director. A well has mechanical integrity if there is no significant leak in the casing, tubing and packer and there is no significant fluid movement into a USDW through vertical channels adjacent to the injection wellbore.

2. EPA should not specify minimum frequencies for mechanical integrity testing (MIT) in the rule because that would preclude MIT plans that are tailored to specific site characteristics and operating parameters. Such plans could include effective provisions for decreasing or increasing MIT frequencies based on triggering criteria that are designed to effectively maintain MI while minimizing costs and administrative burdens.

G. Measurement, Monitoring and Verification (MMV)

1. Operators could be required to conduct baseline geochemical analysis within the injection and confining zones before injection commences.

2. Operators should monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics and to demonstrate their compatibility with the well materials.

3. When determined necessary by the Director, operators could be required to monitor geochemical changes in formations of the confining zone using a monitoring approach that could be conducted from injection or observation wells, that are constructed consistent with the recommended requirements and whose number and location are sufficient to monitor geochemical changes.

4. Operators should be required to conduct monitoring to evaluate the injection zone performance using methods and frequencies acceptable to the Director. There should not be an explicit requirement to monitor plume movement, which could be difficult and expensive and which is truly unnecessary if appropriate monitoring parameters are established to ensure adequacy of the confining zone or system.

5. Operators should develop and implement a plan for monitoring chemical and physical changes in potentially affected USDWs within the AOR only

where there is reason to anticipate such changes could be caused by movement of fluids related to CO_2 injection.

6. Operators should report annually, or at a frequency acceptable to the Director, on the characteristics and volumes of injection fluids, injection pressures, flow rates, and annular pressures, the results of MITs, the extent of the injected CO_2 free phase plume and pressure front and any other monitoring results deemed necessary by the Director.

7. Operators should conduct post-closure monitoring, and associated modeling, for a period sufficient to demonstrate to the Director that fluid movement resulting from the injection will not endanger USDWs.

H. Well Closure and Post-Closure

1. Operators should be required to flush wells with a buffer fluid at closure.

2. Operators should ensure that the well is in a state of static equilibrium prior to the placement of the final plug.

3. The requirement should be to plug the well with cement or a suitable alternative in a manner that will prevent the movement of fluid that endangers a USDW.

4. At closure, operators should place and test plugs by a method acceptable to the Director.

5. Prior to well closure, appropriate mechanical integrity testing shall be conducted to ensure the internal and external integrity of that portion of the long string casing and cement that will be left in the ground after closure.

I. Financial Responsibility

1. Operators should be required to demonstrate and maintain financial responsibility for closure of the well(s) and post-closure monitoring.

J. Public Participation

1. EPA should use its current UIC program public participation provisions with the addition of a requirement that the Director issue a public notice after the Director determines that an application is complete and prior to beginning technical review of the application.

V. For questions about these comments or additional information, please contact:

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