State Regulators Workshop on Geologic Sequestration of CO_2

The Environmental Protection Agency (EPA), in coordination with the Department of Energy's National Energy Technology Laboratory (NETL), and the Ground Water Protection Council (GWPC) held a workshop on geologic sequestration of carbon dioxide (CO_2) on January 24, 2007 in San Antonio, Texas. At the workshop, representatives of state governments, EPA Regions, DOE research laboratories and Regional Partnerships, industry, non-governmental organizations (NGOs), academia, and other interested parties met in small groups to discuss issues associated with CO_2 injection for the purposes of geologic sequestration (GS).

Participants were asked to formulate questions and identify research needs to be addressed as EPA prepares to develop a scientifically-sound management strategy for CO_2 injection. The participants were organized into groups of 8 to 10 people, with each group having a mix of representatives from EPA regions, states, industry, research institutions, academia, and NGOs, to allow for sharing various points of view. The group discussed the following topics: site characterization; modeling; area of review (AoR); injection well construction; mechanical integrity testing (MIT); measuring, monitoring, and verification (MMV); closure and post-closure care; and liability and financial responsibility.

Below is a compilation of the questions, comments, and observations raised at the workshop. Note that some of the points raised are out of the scope of an EPA management framework; they are included here for completeness.

Site Characterization

Questions

- What are the ideal parameters for an injection reservoir?
- What is the impact of a buoyant fluid?
- What geomechanical studies are needed to determine fracture pressures?
- Can the original pressure in a depleted reservoir be an acceptable default for CO_2 injection?
- What petrophysical data will be needed? How do rock properties affect seal requirements?
- How should "produced" (i.e., displaced) water be managed?
- In areas with pre-existing seismic stresses, how important is seismic data for site consideration?

Comments and Observations

The group noted that decisions on appropriate injection sites require many site-specific inputs. The following were offered as information that should be considered in determining whether a proposed site is appropriate for CO_2 injection:

- Faults need to be identified and determinations made as to whether the faults interfere with containment characteristics.
- Fractures must be understood.
- Know the surface exit points (i.e., points of potential surface release and human exposure) for CO_2.
- Understand the geologic column, including porosity, permeability, and trapping mechanisms.
- Characterize the overburden and subsurface structures (e.g., using lithology or outcrop data). Examine cap rock characteristics.
- Identification of the size, capacity, and injectivity of the receiving formation is critical for site characterization.
- Characterize water-rock-CO_2 geochemistry; i.e., what is the significance of mobilizing metals in an oilfield brine?
- Consider coring for chemical testing.
- Consider weather data.
- Accessibility at the surface, e.g., to wildlife, is an important factor.
- Sensitive and populated areas should be assessed.

More detailed geologic site characterization data (e.g., establishing depositional environments) may be required for CO_2 injection than for oil exploration and production.

Generally, the data currently required in UIC permit applications should provide most of the needed information. Most of the Class I guidelines can be used.

Injection pressure should be limited to avoid creating or opening fractures; pressures need to be monitored.

Recognize that there are regional differences in the level(s) of public concern and in the expertise available to evaluate potential injection sites.

Certain sites (e.g., karst areas or active seismic/fault zones) should not necessarily be excluded from consideration, but mitigating factors should be considered in decisions.

Have the regional pilot sites met the ideal parameters for a reservoir or were they selected for convenience?

Research is needed on buoyancy effects/adequacy of cap rock (cap rock integrity is more important for GS than for oil and gas exploration).

Modeling

Questions

- Can models adequately evaluate the impacts of faults and petrophysics?
- How many cross-sections will be needed to provide data inputs for models? 2-D or 3-D modeling would balance sufficient/adequate data and ability to explain results to the public and others.
- Should conservative estimates be made for modeling purposes to reduce vulnerability to human health and the environment?
- Will the use of “agency accepted” models be required?
- Should there be a standard, publicly-available model?
- How can we correlate the various models that are currently available?
- Should modelers be certified or meet minimum qualifications?
- How can time scales be incorporated into models?

Comments and Observations

Participants provided varying opinions on the appropriateness of existing models for CO_2 injection. Some felt that existing oil and gas reservoir models can be easily adapted to CO_2 injection into saline formations, since they are less complex systems. Others felt that the multi-phase nature of CO_2 requires more sophisticated modeling.

Models can provide reasonable estimates, provided there is enough input data to do the modeling. A carefully designed data collection program for model inputs is needed.

Models should be validated by comparing model results to real-world data.

Models must be continuously updated and recalibrated as new data become available.

Modeling timeframes of 500 years should be sufficient. Long-range predictions cannot be confirmed (10,000 years is unrealistic).

Look for models with simple parameters that provide reasonable results.

Quality baseline data (e.g., on water-rock interaction and mineral reactions) is needed to serve as inputs for the models.

Reporting requirements should include model validation (i.e., what was predicted, how accurate models were).

A variety of models are acceptable, but there are benefits to standardization.

Regulators and operators must agree on the model to be used (i.e., information and simulation process).

Models should be conservative ("conservative" needs to be defined).

Area of Review (AoR)

Questions

- Can existing UIC AoR study methods address CO_2 sequestration issues (e.g., buoyant fluids), or must a new method be developed?

- Are standard procedures for AoR studies needed? What should the role of models be? How many details does the regulator need for models applied to AoR studies (e.g., calibration, sensitivity analysis)?

- Is a radial flow model useful or acceptable for CO_2?

- Do we have adequate information on CO_2 impacts to aquifers?

- For what timeframe should an appropriate area of influence be considered (1 year to 500 years)?

- How much information on well integrity and the number of wells in the area of review is needed? How can old abandoned wells be identified?

- Is research needed to distinguish areas of elevated pressure (extending beyond the plume) vs. area of plume migration (in post-closure conditions)?

- How would the AoR for horizontal wells be determined?

Comments and Observations

Participants offered varying opinions on the appropriateness of using a fixed-radius AoR. Some felt that a fixed radius AoR is not appropriate; others said that a fixed AoR can be used initially, but an area similar to the zone of endangering influence (ZEI) should be used if sufficient data exists to more accurately define the AoR. Some felt that a fixed minimum radius would be appropriate, although a maximum radius cannot be set. Others said that AoR studies should be based on volumes of CO_2 injected and the pressure influence.

The following considerations for an AoR study were offered:

- The extent of the CO_2 plume and extent of pressure increase are important information. The AoR should be based on injection volume, injection pressure, and plume movement during the period of interest (which needs to be defined).

- AoR determinations must recognize the two-phase nature of the injected CO_2.

- Include information on geologic systems (e.g., deep karst, fluvio-deltaic channels, and sheet sands).

Research how old wells with old plugs have held up to injection underneath or nearby. If they demonstrate integrity, the presence of older wells in the AoR may be acceptable.

Some areas with old, undocumented penetrations may not be good candidates for CO_2 injection (exclusion zones) unless injection is into significantly deeper formations.

AoR and ZEI are not adequate terms. New terminology is needed to reflect pressure, injection, CO_2 migration, and possibly surface effects.

Participants offered the following comments and observations about corrective action on wells in the AoR:

- CO_2 -water-cement interactions must be further characterized. There are 30 years of oil industry data.

- Corrective action must be identified and addressed in the permit application process.

- Tailor the response to the extent of the problem.

Well Construction

Questions

- How susceptible are well materials to CO_2?

- What effect will impurities either in the injected CO_2 or created through dissolution have on the injection well and on wells in the AoR?

- Is a standard packer adequate for CO_2 injection?

- What types of cement are adequate for CO_2 injection?

- What is the potential for well blow-outs and how can wells be designed to avoid them?

- Are there any new well drilling and casing options? What are the implications of laser drilling and expandable casing for CO_2 injection?

- Are there any new well intervention techniques?

- What are the implications of introducing microbials into the well for sealing?

Comments and Observations

Use expertise from existing CO_2 injection wells in enhanced oil recovery (EOR) operations for constructing CO_2 GS wells. For example, there is an American Petroleum Institute (API) study on well construction.

Continue to research how wells that have received CO_2 during long-standing EOR operations have held up over time.

CO_2 wells that inject into saline formations should be constructed to Class I standards.

Ask a professional organization (e.g., ASTM) to develop construction standards for CO_2 sequestration wells.

Construction materials should be carefully selected, monitored, and modified over time as necessary to adapt to site conditions, the injected stream, and operating parameters. Appropriate materials exist today.

Properly designed and constructed wells should be able to last for a sufficient period in the presence of the injected CO_2.

Research is needed on additional well sealing methods and into eliminating cements through expandable casing.

Mechanical Integrity Testing (MIT)

Questions

- How effective are current MIT techniques in the various circumstances being used for pilot projects? Which tools are more effective? Which MITs should be used on which types of wells (e.g., production wells)?

- Should MIT be required for <u>all</u> wells in a field with CO_2 sequestration?

- Should micro-annulus leakage be evaluated?

- How much fluid leakage during MIT is acceptable?

- Is there an I_{131} isotope that is soluble in CO_2 for use in the radioactive tracer survey (RTS)? If not, can another radioactive tracer be used?

- Is continuous pressure monitoring necessary?

- What is the most effective annular fluid that will not react with CO_2?

- What is the best way to test for movement around the casing?

- If it can be demonstrated that the casing is secure to water, is it secure to CO_2?

- What is an acceptable amount of mechanical integrity (MI) loss (e.g., 5 percent)?

Comments and Observations

MIT should be conducted on a regular basis (at a frequency to be determined). Part 1 and 2 MI demonstrations should be frequent at first, and the frequency may be reduced with experience, as appropriate.

Explain that MIT failure is not the same as a release to the environment.

Wells used for CO_2 injection should be continuously monitored to verify MI.

A broad array of tools is acceptable. A list of available MIT tools would be useful.

Develop a consistent national approach to calculating maximum injection pressure. A new MIT may need to be developed.

Standard definitions are needed.

Cement records are insufficient; additional MITs are needed for CO_2 injection.

Participants offered suggestions for research topics related to MIT:

- The impact of phase changes on MIT tools.
- The impact of pressures, i.e., above injection zone, to avoid damage to the well.
- Temperature effects along the length of the borehole and casing.
- The appropriateness of temperature logs, noise logs, oxygen activation tests, and RTS.
- Correlating well failures with injection history.

Measuring, Monitoring, and Verification (MMV)

Questions

- What sensors can be used? Are current down-hole CO_2 detection tools acceptable?
- What happens if CO_2 is detected? Is corrective action needed? What parameters need to be set to determine compliance?
- How can leakage be quantified? How well will total volumes injected be known (i.e., within 5 percent), and how can we verify 100 percent containment?
- Should an odorant be added to the injected CO_2?
- Should the operator's monitoring/verification responsibilities be included in the permit?
- How will the Underground Injection Control (UIC) and Office of Air and Radiation (OAR) programs interact on MMV processes?
- Assuming there will be CO_2 migration, should low migration rates be measured and documented?
- What if fluids move up-gradient into overlying aquifers?
- What is an appropriate time frame for 4-D seismic monitoring?
- Should monitoring for carbon credits be linked to human health and the environment?

Comments and Observations

Do not set an arbitrary leakage rate. If acceptable leakage rates are set too low, demonstrating compliance becomes impossible. CO_2 must be allowed to migrate out of the injection zone; this is not leakage. Rather, the concern is about migration to the surface.

Some leakage will occur, and research on leakage will help advance our understanding of what factors might increase leakage rates. This information can be used to improve site selection, well construction, etc.

Baseline surveys are important, e.g., initial baseline chemistry data from private water wells. These conditions can help assess leakage.

Use a tracer in the CO_2 injection stream to make it possible to identify the source.

Monitor within the first porous zone above the confining layer.

Look at geochemical changes.

Research should focus on what is necessary to protect human health and assure safety.

One-size-fits all MMV approaches will not work. Site-specific determinations are needed. Focus monitoring in areas of anticipated activity. Distinguish between pilot/demonstration projects and industrial projects.

The sensitivity of measurement tools must be understood. Sensitivity of all tools should be increased.

Conduct atmospheric monitoring in the vicinity of the injection well.

Light hydrocarbons (e.g., methane) can also migrate and are an issue.

Closure/Post Closure Care

Questions

- Should specialized cements be used to plug all or part of the well?
- Will a CO_2 pressure zone create concerns for future drilling (e.g., for resource exploration or production or waste disposal)?
- For how long should post-monitoring be conducted, if at all? Should the permit application include a post-injection modeling plan (in advance of closure)?

- Do current institutional controls cover all closure and post-closure requirements? Are new controls needed to protect human health and the environment?

Comments and Observations

Closure requirements must include physical specifications as well as a post-closure MMV regime (details should be defined).

Closure requirements should be on a project-wide basis, not for individual wells.

Proper plugging and abandonment of injection wells is important.

Post-closure monitoring should include: pressure falloff test; seismic monitoring, if appropriate; and monitoring in and above the injection zone and the USDW.

CO_2 plume monitoring requires a unique monitoring regime. Performance confirmation to assure that the plume is moving where it is supposed to is needed.

Monitoring time frames should be twice as long as the injection period or until there is a 95 percent pressure die-off. This has implications for the question of acceptable leakage.

The main question driving monitoring needs is whether pressure returns to normal levels as expected. If not, then further monitoring might be required. If behavior is as expected, there is no concern for the injection well.

A long-term record-keeping system is needed.

Liability and Financial Responsibility

Questions

- How should liability be apportioned among the operator, generator, and other entities?

- Does the federal or state government bear any responsibility for long-term liability issues?

Comments and Observations: Liability

Liability should last for as long as the injected CO_2 has the potential to cause damage. A suggested timeframe for leakage liability is twice as long as the injection period or until there is a 95 percent pressure die-off.

Consider incorporating notices of prior CO_2 injection into the land deeds within the largest affected area.

Liability for leakage in the long-term should be transferred to the government. This should occur within a reasonable period after cessation of the project. Finance through a CO_2 tax similar to Superfund.

Consider involving financial institutions on long-term liability issues, as they will ultimately determine what we will need to do.

Consider assigning leakage responsibility based on volumes injected. We need a series of post-injection standards that, if met, reduce liability over time, ultimately removing liability (e.g., tendency for plume to move as expected, dissolution of CO_2).

Consider linking liability to a multi-track process. For example, track 1 (to remove liability) if early monitoring indicates acceptable results; track 2 (rigorous closure requirements at the end of the project) if not.

Comments and Observations: Financial Responsibility

Financial responsibility demonstrations should be sufficient to ensure the availability of funds to pay for plugging and securing the wells. Most injection sites will be operated by viable corporations that are financially responsible.

The financial responsibility requirements should be no more rigorous than those for Class I wells.

Review RCRA financial responsibility mechanisms.

Other Issues

What are EPA's roles related to health and safety, climate, economic credits?

What other environmental impacts and requirements are involved?

What should the requirements be for sequestration in coal seams?

Is/should CO_2 be classified as a waste?

Remediation will not be feasible in most cases; it is essential to address health and safety issues and this is a consideration for credits and accounting.

How does the permitting process incorporate public engagement? What are the best methods for public outreach? Public perception is important.

Consider surface and mineral rights identification. Also consider inverse correlative rights, i.e., issues associated with use of another owner's pore space.

Consider permit renewals (e.g., 10 or 15 years) to ensure the project is on track.

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