EPA Technical Workshop on Geosequestration:
Well Construction and Mechanical Integrity Testing
March 14, 2007; Albuquerque, New Mexico

Workshop Notes

EPA held a technical workshop in Albuquerque, New Mexico on March 14, 2007 to address well construction and mechanical integrity testing (MIT) issues as related to geologic sequestration (GS) of carbon dioxide (CO_2). Fifty-one (51) representatives of the oil and gas industry, oil field service companies, academia, U.S. Department of Energy (DOE) national laboratories and Regional Partnerships for Carbon Sequestration, the Interstate Oil and Gas Compact Commission (IOGCC), five States and a Canadian Province, and EPA Headquarters and Regional staff attended the workshop. (See Attachment 1 for a list of the attendees.)

The workshop format included a recap of the International Energy Agency (IEA) Third Wellbore Integrity Network Meeting (held on March 12 and 13, 2007 in Santa Fe, New Mexico); technical presentations on current research by industry, academia, and government agencies; a progress report on the American Petroleum Institute (API) CO_2 well standards; and an introduction to EPA Underground Injection Control (UIC) regulations on selected well types. In the mid-afternoon, workshop participants split into two breakout sessions to discuss research needs on well construction and MIT.

Welcome and Introductions

Bruce Kobelski, EPA Office of Ground Water and Drinking Water, welcomed the workshop participants. He noted that many of the individuals in attendance, and some of the organizations they represent, have not participated in previous EPA GS workshops, and therefore would provide important new perspectives as EPA begins to gather the information it needs to develop a management framework for GS. EPA has participated in and attended many meetings related to GS to obtain input and share ideas with various stakeholders and experts. Recent examples of such meetings include the Ground Water Protection Council (GWPC) meetings on risk framework in Portland, Oregon in September 2005 and on CO_2 injection technical issues in Austin, Texas in January 2006. EPA staff have also attended and participated in a GS Site Characterization Conference in Berkeley, CA in March 2006 and a World Resources Institute workshop on liability issues in Washington, D.C., in October 2006.

Mr. Kobelski noted that EPA is currently assessing options for a management framework for CO_2 injection for the purposes of GS. GS presents many technical challenges that go beyond those associated with CO_2 injection for enhanced oil and gas recovery (EOR/EGR). For example, GS will involve a variety of geologic settings apart from oil and gas reservoirs (e.g., saline aquifers and unmineable coal seams). In addition, the CO_2 from coal-fired power plants will contain impurities (i.e., sulfur and nitrogen oxides, and metals such as mercury) that are not typically found in the CO_2 used in EOR/EGR operations, and GS will involve significantly greater volumes and longer storage times.

Mr. Kobelski pointed out that the current workshop is a follow-up of a State Regulators' workshop held in San Antonio, Texas on January 24, 2007, where representatives from States, industry, academia, and research institutions provided input on research questions that EPA needs to address in developing a management framework for GS. This well construction and MIT workshop is an important first step in the formulation of a research agenda to answer important questions to ensure that GS practices will not endanger underground sources of drinking water and public health.

Mr. Kobelski then reviewed the day's agenda (see Attachment 2). In the first half of the workshop, experts working directly on well construction and MIT issues would provide background information and some key questions on current research activities. (Their presentations are found in Attachment 3; hyperlinks to the presentations are on the titles within these notes.) In the mid-afternoon, the workshop participants would be split into two breakout groups to discuss existing research and research gaps related to well construction and MIT of CO_2 injection wells.

Wellbore Integrity and the Geologic Sequestration of CO_2: A Perspective from the IEA Greenhouse Gas R&D Programme Wellbore Integrity Network

Bill Carey, Los Alamos National Laboratory, provided an overview of the work by the IEA Wellbore Integrity Network. The IEA Wellbore Integrity Network assesses and communicates the state of knowledge and research needs related to the long-term integrity of wellbore systems in CO_2-rich environments. Focus areas include:

- Field experience with CO_2 and wellbore materials, e.g., cement placement; studies of wells exposed to CO_2; and case histories and wellbore statistics especially on legacy wells.
- Monitoring and wellbore logging and results.
- Remediation approaches and costs.
- Experimental research on cement-CO_2 interactions and CO_2-resistant cements.
- Numerical modeling, e.g., CO_2 fate and distribution in the reservoir; transport modeling of CO_2 cement; and leakage simulations.
- Policies and regulations, including API practices, Minerals Management Service (MMS) regulations, and Canadian and European approaches.

The Network has held three annual meetings, the most recent of which was in Santa Fe, New Mexico on March 12 and 13, 2007. Key issues identified include the following:

- Wellbore integrity problems do exist in oil and gas operations and are often due to cementing practices.
- Casing and tubular corrosion can be more rapid than cement degradation.
- Methods to evaluate the leakage potential of older wells and within fields with multiple wells, and remediation methods are needed.
- Needed research on cement includes evaluating the performance of new CO_2-resistant cements and methods to evaluate cement-CO_2 reactions.
- More sensitive logging and field monitoring tools are needed.

- Accessing data to help evaluate wellbore performance from private companies and regulatory bodies should be a priority.

Dr. Carey also described research underway on CO_2-wellbore interaction mechanisms and on reconciling field, lab, and modeling data on CO_2-cement reactivity. Following his presentation, participants offered the following questions and comments:

> *Is anything known about the CO_2 conditions at the Scurry Area Canyon Reef Oil Committee (SACROC)?* Samples taken from above the caprock appeared to be carbonated, although it is unclear for how long and to how much injected CO_2 they were exposed.
>
> *Would wells in a potential CO_2 storage field that have been plugged and abandoned by UIC-approved methods be considered "sequestration-ready?"* A number of participants responded that UIC requirements would only be applicable to injection wells. Production wells are outside of the UIC Program's authority, although they may have followed UIC-approved plugging and abandonment procedures.

CO_2-Cement Interactions: From the Lab to the Well

Matteo Loizzo of Schlumberger Carbon Services Engineering summarized research on CO_2-cement reactions and development of CO_2-resistant cement. Interaction between cement and CO_2 follows a three-step process, which includes carbonic acid diffusion, dissolution/carbonation, and leaching. Cement sheath defects (e.g., placement defects and cracks and microannuli) will accelerate degradation. Carbonation healing/plugging may be effective only at small scales.

A CO_2 resistant cement formulation based on "CRETE" technology and a reduced-Portland binder is being researched. This design optimizes particle size distribution to reduce porosity and permeability and to maximize its mechanical properties and compatibility with CO_2. Mr. Loizzo added that watered-down cement is not suitable for CO_2 injection wells.

Participants asked the following questions of Mr. Loizzo:

> *How does CO_2 affect the compressive strength of the cement?* The strength initially drops and then increases. It is difficult to measure the strength of samples in the lab due mechanical instabilities in the samples that produce spalling. This leads to lower unconfined compressive strength for the full sample than may be expected from the carbonated material itself.
>
> *What type of design could counteract corrosive effects?* The ideal formula is a compromise between the binder and its reaction to the CO_2. Rather than completely eliminating the use of Portland cement, Portland cement is being combined with other cement types.

What exotic cements have been studied? Latex cement, which is used for hydrocarbon gases, has been found to be a poor choice for CO_2 injection. Epoxy cement has also been studied, but it is of limited availability and is very expensive.

Well Integrity Experience in Alberta, Canada

Stefan Bachu of the Alberta Energy and Utilities Board (EUB) presented the Canadian experience with CO_2 injection. In Canada, injection falls entirely under provincial jurisdiction. In Alberta, the EUB has jurisdiction over both oil and gas production and deep well injection and disposal, under the authority of Directive 65 (for disposal operations), and Directive 51 (for well construction). Under these Directives, Class III wells are for injection of hydrocarbons, or inert and other gases, for the purpose of storage or enhanced hydrocarbon recovery; CO_2 is specifically mentioned as an example.

Acid gas injection has been practiced in western Canada since 1990. In that time frame, 6 million tons (the equivalent of a single power plant's annual CO_2 emissions) have been injected; 60 percent of the injection is to saline aquifers and the remainder is to oil and gas fields. To date, only one incident has occurred, where an acid gas injection well in British Columbia failed in 2004 (due to ice formation in the annular fluid). Examples of CO_2-EOR projects in Canada include the Weyburn Field and the Pembina-Cardium project.

Dr. Bachu concluded that existing regulatory requirements and controls seem to be adequate for the operational phase of CO_2 injection; however, there are not yet regulations for the post-operational phase. Proper injection site selection and characterization are important, and monitoring of injection well integrity is critical. The long term effects of the injected acid gas on cements and casing in older wells is not well known, and poorly constructed wells may pose the greatest risk associated with CO_2 injection. The number of abandoned production wells in oil and gas reservoirs is one of the key concerns for GS projects.

Following Dr. Bachu's talk, participants asked the following questions:

Is there anything to report about CO_2 migration or flow in the Weyburn Field? The field is in Saskatchewan, and outside of the EUB's jurisdiction. A participant added that CO_2 migration is occurring but is within the intended formations

What is a typical Area of Review (AoR) for a Class III well? The AoR is determined through modeling. Typical AoRs are on the order of ¼ mile; they may be larger in more complex situations.

Is any of the acid gas injection in Alberta to saline aquifers? Yes; and while permeability changes have been observed, no problems have been identified.

Is the Pembina field part of the DOE pilot effort? No, but the Zama field is, and it is operating.

A Comprehensive Wellbore Integrity Program

Charles Christopher of BP Americas, Inc. presented an overview of the Carbon Capture Project's Sequestration, Monitoring, and Verification program. He outlined the components of a comprehensive wellbore integrity program, including the need for good data on current well inventories, historical statistics on the effects of CO_2, and well autopsies and analysis of recovered cement and tubulars. Good modeling will require an understanding of the mechanisms of attack on cements, and researchers are beginning to understand these and identify appropriate modeling parameters.

Mr. Christopher also provided a status report on a well autopsy/corrosion field study of a CO_2 production well. In October 2006, the tubing and packer were removed, and found be in good shape after 22 years, due to protection by the tubing liner and annulus fluid (in fact, the foundry stenciling was still visible on the tubing). Other testing of the well includes logging, cement evaluations, and X-ray diffraction and scanning electron microscopy of cement cores.

No questions were raised after Mr. Christopher's talk.

Geological Storage of Carbon Dioxide: Models and Parameters

Sarah Gasda of Princeton University provided an overview of models that assess wellbore leakage and geologic storage of CO_2. The study team compared modeling options, including 3-D numerical solutions, vertically-averaged equations, and semi-analytical solutions to assess abandoned well performance and potential leakage. The comparisons focused on the Edmonton-Wabamun Lake Area of Alberta, because data on abandoned well location and formation permeability are available. A combination of analytical and numerical models could allow rapid simulations of mass transfers within aquifers based on permeability inputs to provide a broad assessment of processes occurring within the injection reservoir. The models can also be used to detect critically leaky wells based on pressure changes (i.e., the wells are more permeable than the formation).

Participants offered the following questions and discussion points on Ms. Gasda's presentation:

> *Were any other modeling codes, e.g., ECLIPSE, examined?* These models are slower than the numerical models used and are more appropriate to single well analyses, rather than the reservoir-scale simulations performed.
>
> *The oil and gas industry has used these models at the reservoir scale.* While these models can be used at the reservoir-scale, in non-industry applications (e.g., saline aquifers), fewer data inputs may be available than is typically available for oil and gas fields. Numerical models offer a means to model the reservoir with whatever data are available. They offer a broad-brush approach that generates results that can be presented to the public with a reasonable degree of certainty. The study team has validated their model against the ECLIPSE model.

No migration petitions may serve as an analog to the modeling approach, i.e., bounding the problem. Ms. Gasda responded that the intent of their models is to assist decision-makers in evaluating the fate of CO_2 in storage and these models will also provide useful information to the public by trading off complexities with simpler and easy to understand models.

Selecting Sites for Geological Sequestration: Wellbore Integrity and Other Criteria

Jason Heath, of the New Mexico Institute of Mining and Technology and a member of the Monitoring, Mitigation, and Verification (MMV) and Site Characterization groups of the Southwest Regional Partnership, presented work underway in the Southwest Regional Partnership. CO_2 sources in the study region include power plants and other sources that generate about 100 million tons of CO_2 annually. One of the partnership's first tasks was to identify suitable GS sites. Site selection must consider practical issues (e.g., site ownership and regulatory requirements); technical issues (proximity to high-capacity storage reservoirs and low-risk geology); and well integrity. Sites along existing CO_2 pipelines are preferred.

A well integrity analysis is being performed in the Aneth Unit in southern Utah, which will be flooded with CO_2 in June, 2007, to determine whether CO_2 will leak from the target reservoir and how this can be monitored. There is concern about well construction deficiencies (e.g., insufficient casing and cementing) in older wells in the Aneth Unit. Speculation about the migration of saline water from the De Chelly aquifer upward into the Navajo aquifer by wells was made by some researchers, but well-migration has not been verified. Analysis of well construction deficiencies included temperature logs or cement bond logs and reviews of information on the depth of surface or intermediate casing and cement placement in the wellbore annulus.

Participants asked the following questions of Mr. Heath:

Has any monitoring been performed in the vulnerable wells identified in the Aneth Unit? No monitoring has been performed in the vulnerable wells by the Southwest Partnership. The Southwest Partnership developed plans to monitor groundwater wells in the shallow aquifer in the vicinity of the vulnerable oil wells. However, the oil company denied permission for this monitoring. The landowners are very sensitive to any groundwater sampling in the area – the oil company feels it is best not to bother landowners at present.

An EPA participant commented that US EPA requires the oil company to frequently monitor and periodically test all injection wells for mechanical integrity.

If monitoring could be done, what parameters would the study team monitor? Conductivity, temperature, alkalinity, pH, major ions, trace metals, and isotopes of hydrogen, oxygen, dissolved carbon, and dissolved strontium.

Is any remediation planned? Most of the wells in the Aneth Unit were drilled before the UIC Program was put in place. These "grandfathered wells" will not require remediation unless they are shown to pose a substantial risk of fluid movement into the underground source of drinking water (the Navajo Aquifer). No casing or cementing remediation for any wells is planned at this time. However, wells must be remediated if they show evidence of fluid movement in the uncemented portion of the wellbore annulus or develop casing leaks, and during plugging and abandonment operations. Injection wells with known construction deficiencies will require frequent monitoring for fluid pressure and movement in the wellbore annulus, under the terms of the UIC permit for CO_2 injection in the Aneth Unit EOR project.

EPA Region 9 has not yet received the application for CO_2 flooding at the Aneth Unit. It is possible that after EPA's review of the forthcoming application, some wells may need to be remediated, but since the wells have been "grandfathered," remediation will not be required unless a real danger to the aquifer can be shown. Injection wells that fail mechanical integrity testing or develop excessive pressure in the tubing/casing annulus during operations must cease injection pending remedial work to restore mechanical integrity or must be plugged and abandoned if repairs are unsuccessful.

If CO_2 escapes the Paradox Formation, this could pose a risk; the lack of data poses risk as well. There is a long history of water flooding, and a small CO_2 pilot was performed in the Aneth Unit in 1998. There is some experience upon which to draw. CO_2 leakage has occurred in the past in a nearby unit, into which CO_2 has been injected for 20 years. In this leakage event, holes in the casing caused an apparent discharge of CO_2, along with saltwater and oil, to a shallow aquifer and spring. The well was plugged and the aquifer was remediated; monitoring continues.

Is there any gas in the reservoir? No.

API Activity on CO_2 Well Construction/Integrity and CO_2 Capture and Geosequestration

Ron Sweatman, Global Business and Technical Solutions, Halliburton, presented API's activities related to CO_2 well construction and carbon capture and storage (CCS). Current work includes the API CCS Work Group, which is studying CO_2 EOR practices, and a joint project with the International Petroleum Industry Environmental Conservation Association to develop guidelines (i.e., recommended practices, or "RPs") for emission reductions from CCS projects. The API RP 90 Committee is evaluating annular casing pressure (ACP) management for offshore wells; while not specific to CO_2, this document will provide guidance on wellhead pressures.

The Well Planning and Design task group (RP-65) is studying well casing pressure prevention and remediation practices and recommended practices intended for federal regulations. One product, RP 65-2 addresses pressure barriers and related well construction practices, and is relevant for preventing CO_2 leaks during well construction. This draft document is undergoing final review to resolve comments made on the letter ballot which approved the draft for publication.

The task group is currently developing RP 65-3, "Practices to Prevent or Remediate Annular Casing Pressure [ACP]." The report will present recommended practices to prevent, detect, and remediate ACP during well construction, production, injection, and abandonment (including prevention and remediation of CO_2 leaks). Topics to be covered include preventive practices for sustained well integrity (e.g., well design; diagnostics during well construction; mechanical, chemical, and formation barriers; and MIT) and remedial practices (e.g., ACP detection and diagnostics, well integrity monitoring after abandonment, cementing barriers, and casing/liner pipe repair methods). The casing pressure assessments conducted relate to sustained casing pressure by formation or injected fluids including hydrocarbons, CO_2, H_2S, H_2O, brine, etc. Publication in late 2008 or 2009 is expected.

Participants asked the following questions of Mr. Sweatman:

> *When will RP 65-2 be final?* It should be published in 2007; about 3 to 6 months are needed to address the many comments received on the letter ballot of the last draft and for a possible second vote to decide any unresolved technical comments for the final product.
>
> *What is the difference between sustained casing pressure (SCP) and thermal induced annular casing pressure (on slide 12)?* SCP is caused by annular flow of formation or injected fluids. Thermal induced annular casing pressure is caused by trapped fluid pressure in or near the wellbore.

UIC Program Class I and II Well Construction and MIT Requirements

Brian Graves, EPA Region 6, summarized the federal UIC Program requirements for Class I nonhazardous waste and Class II injection wells, which could serve as a starting point for a management framework for CO_2 GS wells. UIC construction requirements address casing and cement, packer, well materials and cementing; logs and tests; and information about the injection formation. MIT requirements include internal, or Part 1 MIT (i.e., an initial pressure test, then monitoring annulus pressure, and pressure test every 5 years) and external, or Part 2 MIT (i.e., temperature, noise or other approved log every 5 years). For Class II wells, adequate cement records may be substituted for the external MIT.

Participants asked no questions following Mr. Graves' talk.

Technical Breakout Sessions

The participants split into two groups to discuss questions related to construction and MITs for wells that will inject CO_2 for GS and to identify what the groups consider as the top research needs or gaps. Participants were also asked to discuss whether they felt that specific requirements related to construction and MIT or a performance-type standard would be more appropriate for CO_2 GS. Following the breakouts, the entire group reconvened and a reporter from each breakout session reported on its findings.

Session A – Well Construction

Participants in the well construction breakout session generally felt that little additional research on construction materials is necessary, adding that injection well drilling and construction are well developed technologies, and the UIC Class I requirements may be sufficient for CO_2 GS.

They added that the composition of the CO_2 that will be injected may affect construction requirements for GS operations. Bill Carey reported to the group on the discussions during breakout Session A.

General comments and research needs on well construction

- API has developed recommended practices and protocols for properly designed and constructed wells.
- Pilot tests with significant (i.e., real-world) volumes of CO_2 are needed; these would reveal new research needs.
- Performance-based construction standards may be appropriate (Class I hazardous waste wells may be a model). Standards should be based on how long the well is expected to last and on risk.
- Existing protocols were developed based on research over the past 20-30 years (e.g., metallurgy and induced failures); however, much of this research is confidential.
- CO_2 composition (i.e., impurities in the stream) may drive additional research requirements for metallurgy, etc. What impurities would cause the CO_2 injectate to be defined as "hazardous?" CO_2 stream composition will depend on fuel type, capture processes, and transportation requirements.
- What is the "life expectancy of the well" for management purposes, i.e., are we concerned with the injection period (20-30 years) or the abandonment phase (hundreds of years) as well? This will impact management of the well.
- See the "Wink sink" example. Sink holes developed from improperly constructed oil and gas wells in Wink, TX.

- ***Research need:*** developing lower cost materials that perform as well as high-cost materials is needed.

Discussion and research on casing

- Significant research experience from EOR and acid gas operations, e.g., from SACROC, provides a good working basis for well construction.
- API's CCS working group is conducting a survey of CO_2 operators on performance of metallurgy and coatings.
- Abandonment procedures may need to be more stringent for GS (e.g., full cementing of the wellbore). Consider applying temporary abandonment procedures as an interim approach, allowing for monitoring and modifications.
- Casing specifications depend on possible impurities, formation brine, pressure, temperature and operational conditions.
- Internal coatings protect the inside of the casing and degrade.
- Casing options include chrome tubing (see SPE documents), expandable tubing, titanium casing (as in geothermal applications), fiberglass casing, and inhibited packer fluid for additional protection. However, are these costly options needed?

- ***Research need:*** study the impacts of injection at varying depths.

Discussion and research on cementing

- Cement specifications depend on the presence of CO_2 impurities; formation brine; and pressure, temperature and operational conditions.
- API documents list cements and non-API materials.
- Some geological environments (salt domes) may self-heal and close any openings.
- Cement should run the entire length of the wellbore (i.e., per Class I requirements). This cannot always be done and may not be desirable (e.g., cut casing at depth and fill the hole or allow formation collapse).

- ***Research need:*** alternative (non-Portland) cements, e.g., phosphate-based cement (Burkhaven and Halliburton study).

Discussion and research on drilling

- Installed pressure/temperature, pH, and other sensors for monitoring.
- Is there a difference between GS and other drilling operations?
- Deviated wells pose cementing risks.

Session B – Mechanical Integrity Testing

Participants in the breakout session on MIT believed that MIT requirements may need some fine tuning to meet the needs of CO_2 GS operations. In particular, the types of MITs and frequency of testing may need additional evaluation. Participants cautioned that properly constructed and operated CO_2 GS wells should not be damaged by too frequent testing. Matteo Loizzo reported on the discussions in Session B.

1) What information on GS operations is needed/most relevant to selecting MITs that accurately represent the integrity of the well and alert operators to possible problems?

- Most of the CO_2-specific and general MIT information EPA needs already exists with: hazardous waste injection well operators (injection wells); UIC Class II CO_2/EOR operators (injection wells); CO_2 producers (production wells); oil and gas companies (production wells); oil field service companies (injection and production wells); States (injection and production wells), and natural gas storage operations (injection wells). (Note: Natural gas storage operations and production wells are not regulated under the UIC Program.)

- ***Research need:*** Review lab, field, and modeling studies on cement-related micro-annuli self-enhancing (enlarging) vs. self-healing (sealing) conducted by laboratories, the oil and gas industry, and oil service companies.

- Additional note regarding the formal UIC regulatory language of “no significant leak” (re: internal MIT) and “no significant fluid movement” (re: external MIT): some felt that the word “significant” was too ambiguous while others said that this was perhaps intentional to give the primacy or DI authority more flexibility.

2) How do the properties of CO_2 GS operations (e.g., thermal changes, phase changes, corrosivity, and pressures), impact well integrity and the appropriateness/usefulness of various available tests?

- Phase change is probably a more significant mechanical integrity concern than corrosivity. Retaining the CO_2 in a supercritical state may be appropriate.

- ***Research needs:***
  - Phase changes and its effect on flow along the borehole.
  - Research on phase changes should address its possible contribution to CO_2 migration to the surface, whether it could cause injected CO_2 to freeze, possible contribution to well blowouts, its effects of CO_2 coming out of solution, and how phase changes might affect mechanical integrity pressure tests.
  - Do acid gas mixtures (CO_2 and H_2S) and acid gas injection experiences provide information on phase changes?
  - Can temperature changes (in the well system or immediately outside the well in the wellbore) indicate leaks?

3) How would the presence of impurities in the CO_2 stream (e.g., SO_x, NO_x, and H_2S) impact MI of the well and the appropriateness or usefulness of available tests?

- The presence of impurities in the CO_2 may affect selection of the appropriate casing which would, in turn, affect the choice of appropriate MITs.
  (In other words, if well construction is appropriate for the injectate stream, then the selection of the appropriate MIT is straightforward.)
- Impurities may cause scaling and affect MI.
- If impurities are permitted to be present in the CO_2, this would impact appropriate well completions, e.g., specific materials for packers would be required.
- H_2S can affect phase change properties; however, removing impurities may be cost-prohibitive. H_2S is more toxic than CO_2.

- ***Research need:*** Additional research is needed on the impact of impurities (and the impact of wet vs. dry CO_2) on well mechanical integrity. SO_x is the greater concern, because it combines with water to form sulfuric acids.

- Additional notes: Oil and gas industry has MIT performance regulations for production wells. Also, one participant speculated that operators know which MIT would result in the lowest chance for MIT failure given the specific conditions of the well being tested, and that some operators might choose to use this "lowest performing," yet UIC-approved MIT. This prompted the question of whether operators should be allowed to select the MITs to use.

4) What MIT data from existing CO_2 injection wells is useful for predicting MI and testing needs at the scale anticipated for GS?

- In Texas, casing problems are very rare; cement squeezes are sometimes needed.
- There are differences in the impacts to well systems from corrosive injectate vs. corrosive geologic/oil and gas zones (affecting cement and casing).
- Tubing and packer leaks are prevalent in older fields. Annulus leakage is common in older wells. This may be a problem for EOR wells. If there are CO_2/EOR tubing problems, appropriate MITs are available.
- Much information from monitoring of excessive pressures is available.

- ***Research needs:***
  - Examine external MIT failure rates; operators are required to report this. Examine the few, rare cases of cement problems in Texas; can these cases be linked to a construction problem or a corrosion problem? (Does corrosion only become a problem ***if*** there is a pre-existing construction problem?)
  - Further research on the Texas Railroad Commission UIC/MIT data.

5) How do the MIT failure rates for Class II wells that inject CO_2 compare to other injection wells?

- This information would be available in workover reports and daily logs.

- ***Research need:*** Further research the data from the Texas Railroad Commission on MIT failure rates by injectate type (i.e., acid gas, CO_2, fresh water, and brackish water).

6) Have any Class II wells that inject CO_2 experienced leakages along the borehole either to the surface, or into USDWs or other formations? If so, was the CO_2 a contributing factor to the leakage?

- One case involved leakage in the long-string casing that caused movement of CO_2 into an aquifer and spring. A report is available from EPA Region 9.
- The "Salt Creek Field" reportedly had/has a CO_2-related leak. (Follow-up with Schlumberger.)

7 & 9) How do the properties of CO_2 GS operations (e.g., thermal changes, phase changes, corrosivity, and pressures), impact well integrity and the appropriateness or usefulness of various available internal and external MIT procedures?

- It is possible to measure the casing thickness.
- Electrical resistivity logs can detect pitting and other casing problems, and televiewers can be used to assess the integrity of the casing. These MIT methods are pretty well understood.
- The value of the use of these known MITs will be increased if well construction and MIT selection/use is better integrated.

8) How might the temperature changes associated with injecting supercritical CO_2 affect pressure tests?

- ***Research needs:***
  - Research the phenomenon of a cold injection fluid opening up or enlarging gaps within the well system.
  - Impact of large temperature differentials between injectate and well system/formation on pressure tests. Industry may have a lot of information on this subject.
  - How would CO_2 in the annulus affect a pressure test?

10) What is the best way to test for fluid movement along the casing in CO_2 GS wells?

- While existing MITs can detect fluid movement, these MITs and other available monitoring methods cannot detect the rate or volume of movement.
- Advanced mapping tools may be needed.

- ***Research need:*** Monitoring methods/MITs that could detect rates and volumes of fluid movement along the casing (not just the presence/absence of movement).

11) What is the data quality of the cementing records for CO_2 injection wells, and how does this compare to external MITs or logs?

- Cement records are important and necessary for monitoring and documenting well construction.
- Cement records are not an appropriate substitute for digital logs or external MITs for CO_2 injection wells.

12) Is there an isotope that is soluble in CO_2 for use in the radioactive tracer survey?

- Yes – some/many are available (and are expensive).

13) Over what time frames do MI changes occur in CO_2 injection wells?

- Gross mechanical integrity problems appear early on.
- Early MITs, plus subsequent monitoring allow for developing a staged approach to managing risk.
- MMS may have developed a regulation to address this (infrequent MIT is acceptable if no problems appear).
- See API 90 report.
- MITs every 5 years may be too infrequent.

- ***Research need:*** Research regarding time frames of MI changes and necessary MIT frequency. (Note: This directly relates to research needs under question 1 on self-enhancing vs. self-healing micro-annuli and question 14 on the Texas MIT data to see if new or old wells tend to have MIT failures.)

14) Is successful performance early in the life of the project an indicator that MI will be maintained over the long term?

- This is addressed in the risk framework.

- ***Research need:*** Texas may have useful data on MIT failure rates (for example among new vs. old wells; see related research needs for questions 4 and 13).

15) What annular fluids will not react with CO_2?

- Existing geochemistry studies can answer this question.

16) What methods are available to evaluate micro-annulus leakage in CO_2 GS wells?

- Existing MITs can evaluate the presence/absence of flow along the outside of the casing.

- ***Research need:*** If more than presence/absence information on flow/leakage is needed, then research is needed on the rate and volume of flow/leakage (see question 10).

Next Steps/Closing

EPA will prepare notes of the meeting and make them available on its website. EPA will take everything discussed in the workshop under consideration as it develops the well construction and MIT components of the GS management framework. Participants are invited to send additional ideas or comments to GSworkshops@cadmusgroup.com.

EPA plans to hold other technical workshops in the coming months. While these workshops have not been scheduled, anticipated topics include site characterization, Area of Review, and liability and financial responsibility. EPA also plans to hold a meeting on risk analysis and framework, possibly in conjunction with the World Resources Institute liability workshop this spring.

EPA will continue to participate in other events related to GS. Some examples in the coming months include:

- American Association of Petroleum Geologists (AAPG) Annual Convention is being held on April 1-4 in Long Beach, California. The agenda includes sessions on GS and EOR.

- A Schlumberger/Massachusetts Institute of Technology workshop will be held in Cambridge, Massachusetts on April 23 and 24.

- The Interstate Oil and Gas Compact Commission (IOGCC) will meet in Mobile, Alabama on May 5-8.

- The next IEA Well Monitoring Network Meeting will be held on October 31 and November 1 in Edmonton, Alberta.

ATTACHMENTS

1. Workshop Participants
2. Workshop Agenda
3. Presentations

Workshop Participants

James Anderson; Shell Oil
Stefan Bachu; Alberta Energy & Utilities Board
Lawrence Bengal; Oil and Gas Commission of Arkansas
Kevin Bliss; Interstate Oil and Gas Compact Commission
Glenn Breed; Wyoming Department of Environmental Quality
Bill Carey; Los Alamos National Laboratory
Robert Carpenter; Chevron Energy Technology Company
Rick Chalaturnyk; University of Alberta
Carl Chavez; NM Oil Conservation Division
Wendy Cheung; US EPA Region 8
Charles Christopher; BP
Jesse Claffey; Schlumberger Carbon Services
Karen Cohen; U.S. Department of Energy/NETL
Cal Cooper; ConocoPhillips
Andrew Duguid; Schlumberger Carbon Services
Richard Ezeanyim; Oil Conservation/EMNRD
Mark Fesmire; New Mexico Oil Conservation Division
Craig Gardner; Chevron
Sarah Gasda; Princeton University
Brian Graves; US EPA Region 6
Tor Harald Hanssen; Statoil ASA
Jason Heath; New Mexico Tech
Bruno Huet; Princeton University
Scott Imbus; Chevron Energy Technology Co.
Nicolas Jacquemet; BRGM (French Geological Survey)
Peter Jordan; Subsurface Technology, Inc.
Steve King; Subsurface Technology, Inc.
Bruce Kobelski; USEPA
Jonathan Koplos; The Cadmus Group, Inc.
Randall Larkin; Consultant
Samuel Lewis; Halliburton
Harry G. Limb; ConocoPhillips
Matteo Loizzo; Schlumberger
Chuck Lowe; Ohio EPA
William Mann; US EPA Region 4
Frans Mulders; TNO
Jean-Philippe Nicot; Texas Bureau of Economic Geology
William O'Connor; US Dept. of Energy
Michael Parker; ExxonMobil Production
Robert Puls; Ground Water & Ecosystems Restoration Division, EP
Shari Ring; The Cadmus Group, Inc.
Daniel Sanchez; NM Oil Conservation Division
Allan Sattler; Sandia National Laboratories
Elizabeth Scheehle; US EPA

Chi Ho Sham; The Cadmus Group, Inc.
Arne Valland Singelstad; Statoil ASA
Donald Stehle; Sandia Technologies, LLC
Ronald (Ron) Sweatman; Halliburton
Richard Theskin; California Department of Conservation, Division of Oil & Gas
Robert Van Voorhees; Bryan Cave LLP
James Walker; USEPA Region 9