EPA Geologic Sequestration Technical Workshop: Geological Considerations and Area of Review Studies July 10 and 11, 2007; Washington, DC

Summary Notes of the Workshop

US EPA held a technical workshop in Washington, DC on July 10 and 11, 2007 to discuss geological considerations and Area of Review (AoR) issues related to geologic sequestration (GS) of carbon dioxide (CO_2). Seventy-one (71) representatives of the electric utility and oil and gas industries, 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), State and Federal geologic surveys, States, and EPA Headquarters and Regional staff attended the workshop. See Attachment 1 for a list of the attendees.

The workshop format consisted of three sets of presentations during which industry and government experts described current research on geologic and anthropogenic features that can impact the suitability of sites for GS and corrective actions for wells in the AoR for proposed GS sites. Following each set of presentations, workshop participants split into two separate "breakout" sessions to discuss research needs related to the presentation topics. During the concluding afternoon of the workshop, a panel of experts representing the Regional GS Partnerships and IOGCC presented their experiences with pilot and experimental GS projects and responded to questions from the other participants. The workshop agenda is included as Attachment 2 of this document.

Welcome and Introductions

Bruce Kobelski, EPA Office of Ground Water and Drinking Water (OGWDW), welcomed the group and thanked them for their attendance and input to EPA's efforts to develop a management framework for GS.

Cynthia Dougherty, Director of OGWDW, commented that this workshop is part of a series of EPA-sponsored technical workshops to gather input on GS issues to support development of a management framework for GS. EPA held a technical workshop on well construction and mechanical integrity testing issues in Albuquerque, New Mexico on March 14, 2007 and plans, in the near future, to hold additional GS workshops on measurement, monitoring, and verification (MMV) technologies as well as long-term liability and financial responsibility.

Ms. Dougherty explained that these workshops will help EPA address the technical challenges associated with safeguarding public health and the environment through sound management of GS 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 likely contain impurities (e.g., 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.

Brian McLean, Director of EPA's Office of Atmospheric Programs (OAP), provided an overview of the Office of Air and Radiation's involvement with the various technologies and efforts that contribute to the portfolio of options to reduce greenhouse gas emissions and address climate change. These responsibilities include the ENERGY STAR Program; Green Power Partnerships; climate program assistance to state and local governments, industry and international partners; development of the national greenhouse gas inventory; and collaboration with DOE on numerous climate change-related projects and programs. OAP is working closely with OGWDW in EPA's efforts on ensuring GS is properly managed and deployed.

Session 1: Geological Considerations—Natural Features

The first session of the workshop explored information about natural subsurface geology that is needed to determine whether a site is appropriate for geologic sequestration. (The speakers' presentations are found in Attachment 3.)

Characterizing and Selecting Appropriate Sites for Geologic Storage of CO_2, Key Issues and Information Needs

Jens Birkholzer, Lawrence Berkeley National Laboratory, kicked off the session by discussing the key geologic attributes of a good storage site relating to injectivity, storage capacity, and containment effectiveness. Dr. Birkholzer highlighted the importance of adequate site-specific characterization and outlined the information needed to characterize a potential storage site. He described the general process for characterizing a potential site; the information needed to characterize injectivity, storage capacity, and containment effectiveness; available methods and data sources to gather this information; and models that can be used to evaluate this data. He concluded by summarizing some of the information that regulators would likely need to adequately understand the geology of a proposed GS site. Basic expectations include: models of regional and local geologic structure; detailed evaluations of the target reservoir and main seals; plume migration and brine displacement predictions, and; monitoring and remediation plans. Additional expectations may include geomechanical and geochemical studies of seal integrity; an impact assessment for credible leakage scenarios, and; evaluation of geochemical changes in the target reservoir.

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

> *Over what time frame is CO_2 storage being considered?*
> No specific decisions have been made. Site assessment should consider the injection period, typically decades, and an appropriate post-injection period, probably hundreds of years or more.

At a less than optimal site, what form of remediation would be appropriate for a commercial scale GS project?
There is no "standard answer" to this question. A few options might be technologies to seal or re-seal faults, or pressurizing the formation above the injection/storage zone to create pressure differentials/traps between layers. Impacts to underground sources of drinking water (USDWs) are another concern. Water quality problems in ground water aquifers, which can result from inflow of leaking CO_2, can probably be remediated with standard techniques from other groundwater contamination incidents.

Would reservoirs that have been deliberately fractured pose a problem?
This would be more of a problem if the cap rock above the reservoir were cracked. A fractured reservoir may make injection easier.

Teapot Dome Field Experimental Facility: Characterization of a Century-Old Oil Field for CO_2 Injection, Part I: Geologic Features

Mark Milliken, DOE Rocky Mountain Oilfield Testing Center, introduced the Naval Petroleum Reserve No. 3 (NPR-3) site at Teapot Dome in Wyoming. He described the site's stratigraphy, geologic structure, and depositional environment, focusing on the Tensleep Formation, in which declining oil production makes it a potential CO_2 GS target. The sandstones in the Tensleep Formation are Pennsylvanian in age and are of eolian dune origin. The formation is very heterogeneous, exhibiting porosity (and sometimes permeability) changes over very small distances. Prediction of the higher porosity areas is important for determining appropriate targets for GS and predicting CO_2 movement. In addition to seismic studies of the Tensleep, additional studies are underway to examine fault seals, conduct soil gas flux analyses, assess carbonate fracture filling characteristics, and study reservoir geomechanics.

Participants asked the following questions after Mr. Milliken's talk:

What is the channel in the Dakota formation in the geologic cross-section?
Although it could be a channel filling of some type, it might actually be a fault seal rather than a channel. Drilling and development haven't started, so we're not yet sure.

What type of modeling is being done? Are they finding all major fractures through 3-D seismic surveys? Is there minimum set of data?
The data set and surveys are limited to the Naval Reserve property, so our search for all major faults and fractures is hindered by property boundaries. We are now refining our 3-D models and modeling faults and geologic structure as well as porosity and permeability.

An Assessment of Geological Carbon Sequestration Options in the Illinois Basin-Subsurface Geological Considerations in Carbon Sequestration

Rob Finley of the Illinois State Geological Survey described several GS test sites in the Illinois Basin. In a small "huff and puff" experiment, CO_2 was injected into the Cypress Zone in the Loudon Field in Fayette County, Illinois in March 2007. After the CO_2 was allowed to remain in the formation, its movement was monitored through four monitoring wells. Dr. Finley also described a planned enhanced coalbed methane (ECBM) injection site in the Springfield coal seam in Wabash County, IL. Coal cleat orientations help to predict the direction of CO_2 movement (permeability is best in the face cleat direction) and these have been extensively studied and are well known. The plan is to inject over a period of 20 to 30 days through a single injection well and monitor in two wells. The COMET model was used to identify the appropriate spacing of the monitoring wells (approximately 150 feet from the injection well). Drilling should begin in July 2007. Dr. Finley also described the Mt. Simon Sandstone, a deep saline formation proposed as the GS reservoir for a FutureGen project site, and the Archer Daniels Midland (ADM) test site in Decatur, IL, where CO_2 produced by an ethanol plant will be injected beginning in 2009. The Mt. Simon Sandstone was described as well-suited for GS; it is very thick (1,300-2,000 ft), very deep (6,000-9,000 ft), has a large estimated storage capacity with good reservoir qualities in some of the deeper horizons, is overlain by the thick Eau Claire Shale for good containment, has a very limited number of deep penetrating exploratory wells, and is significantly deeper than the source of most of the region's drinking water (relatively shallow 200-300 foot deep glacial aquifers).

Participants asked the following questions of Dr. Finley:

> *Have circumstances ever warranted water extraction from saline formations?*
> No, and this is not anticipated at Mt. Simon. And the reservoir is so large that a very large volume of CO_2 would need to be injected before fluid displacement in this reservoir became an issue. Studies show little change in pressure at a distance from the injection well. Nevertheless, modeling of the system has been planned for next year and regional implications from the GS project will be evaluated in the context of where and what (degree of) pressure increases might occur.
>
> *How was the choice of a 2-D, rather than 3-D model, made?*
> The 2-D model served as a reconnaissance tool. If no "show stoppers" are found with the 2-D modeling study, then drilling will commence. Usually 3-D modeling would be done before drilling, but we'll do it after.
>
> *Who owns the right to sequester CO_2—the land owner or holder of the mineral rights?*
> In Illinois, it is likely to be the surface land owner and not the mineral rights owner.

At the ADM site, is it expected that CO_2 will migrate off-site during the test?
No, the surrounding property is owned by ADM and Caterpillar, and the CO_2 is expected to stay within site limits.

Following the session, participants broke into two groups to discuss questions of research needs relating to evaluating geological features at proposed GS sites. (The questions discussed reflect the input of participants at the State Regulator's Workshop in San Antonio in January 2007.) The general findings of the two discussion groups are summarized below:

How do the properties of injected supercritical CO_2 (e.g., buoyancy, multi-phase nature) affect siting decisions?

- Containment is a function of geology/facies changes and CO_2 phase changes. Multiple geologic barriers can overcome some buoyancy effects and provide added safety.

- Site-specific geological characterizations are necessary. An adaptive performance-based approach to characterization may be appropriate.

Should certain settings (e.g., significant karst regions or highly faulted terrain) generally be considered unsuitable for CO_2 GS? If not, what mitigating factors should be considered in siting/permitting decisions?

- No areas should be excluded without knowing details of the entire geological system (e.g., sealed paleo-karst areas could be good GS targets because of the space in the features).

What geological data (e.g., cap rock integrity and depositional environment) are needed to adequately characterize a site as suitable for CO_2 GS? Is the site characterization data that are typically collected for oil and gas exploration sufficient to characterize a site as suitable for CO_2 GS?

- The amount of data needed depends on the complexity of the site (more complex sites might require more data; some simpler sites may need only limited data). Gather whatever data is needed to "prove the case" that the site is suitable.

- The characterization process needs to be iterative and flexible, and based on a performance standard. Begin the characterization by gathering general information (e.g., seismic and surface data); follow up with modeling and additional tests for details and data. Literature reviews and maps are needed as well.

- A process to confirm and calibrate structural models is needed (e.g., to verify there are enough data and that all the data are plausible).

- Data exists at different scales, and it may be necessary to screen sites at the large scale. At smaller scales, existing data and available methodologies may not be sufficient. If GS is to typically occur in deeper formations than is typical for EOR, starting from scratch may be needed. Well control is another important consideration.

What impact does the buoyant nature of CO_2 have on the suitability of GS in geologic reservoirs with moderate or significant faulting and/or fracturing?

- The impact of the buoyant nature of CO_2 depends on the site and the presence and characteristics of faults and fractures in the reservoir. It is important to understand whether the faults and fractures are sealed (i.e., sealing faults) or not.

What information regarding seismicity is important?

- Understand the history of seismicity and the presence/depth of seismic sources in the area (within 10 km).

- Examine mass changes potentially associated with tectonic stresses (e.g., look at mine flooding/dewatering).

- Identify faults that are close to failure.

What petrophysical data (e.g., porosity, permeability) are necessary to characterize the injection and confining layers?

- Reservoir pressure concerns include fractures, stress, rock strength, *in situ* fluid pressures for cap rock and reservoir, microseismicity, and fracture pressure changes as reservoir pressure increases. (And rather than referring just to the "caprock," the term "seal" or "containment system" is probably more appropriate.)

- Research is needed on the impact of CO_2 as a solvent on various formation types (e.g., shale).

What information about faults and fractures at a proposed GS site is most relevant (locally and regionally)? How can determinations be made as to whether these would interfere with containment?

- Information on fractures, stress, fracturing within the reservoir, rock strength, and *in situ* fluid pressure is needed.

- Research is needed on how (and whether) injection influences regional seismicity.

- Is 2-D seismic adequate for determining if a fault is sealed or not?

What information about the presence/location of USDWs and other aquifers at a proposed GS site is most relevant?

- Understanding the geochemistry of an aquifer may help to rule out some concerns about the GS. Research into the major US aquifers and their vulnerabilities may support this.

- Research is needed on the impact of brine migration and CO_2 pH impacts to aquifers.

Session 2: Anthropogenic Features in the Area of Review

The second session focused on the role of artificial conduits in the AoR on siting decisions, including what types of and how much information about active and abandoned wells is needed to determine whether a site is appropriate for GS.

Potential for Near-Term Carbon Capture and Storage (CCS) Deployment in the USA

Jim Dooley, Pacific Northwest National Laboratory, focused on the current, non-trivial scale of CO_2 injection already underway in the U.S. in the absence of legislation constraining CO_2 emissions, and the significant potential for rapid, widespread increases in CO_2 injection under various legislative proposals currently being debated in Congress. Dooley noted that any proposal to address climate change will, either explicitly or implicitly, create a financial penalty for venting greenhouse gases (GHG) to the atmosphere, and that minimizing societal costs of addressing climate change will require that this price start relatively low and rise over time. Because the price of CO_2 under many of these policy scenarios is unlikely to rise above \$25/tCO_2 in the very near future–the threshold commonly discussed as the price at which the electric power sector will embrace CO_2 GS as a baseload technology–it is sometimes assumed that the commercial deployment of GS technologies is many years if not decades away. However, the analysis presented by Dooley and his colleagues showed that there are a significant number of anthropogenic CO_2 sources with high-purity streams–including ethanol and natural gas processing facilities–that would find GS to be an economic means of reducing GHG emissions at prices that could easily be seen within just a few years of adoption of a national climate policy, and well below the magic \$25/tCO_2 price. With potentially significant GS deployment only a few years away–rather than decades–society might not be afforded the luxury of time to perfectly characterize GS sites or to fine-tune the CCS technology. Once a climate policy is enacted, there could be hundreds of dedicated CO_2 injector wells and a cumulative CO_2 injection AoR that is thousands if not tens of thousands of square kilometers in size within just a few years. Ensuring safety and effectiveness of multiple projects coming online in the near term will require a framework to inform AoR evaluation for GS projects, incorporating considerations that include the number of existing, abandoned or unknown wells near a potential site, the protection of ground water resources, an understanding of natural hazards at the site, and other non-technical siting factors, including the presence of human and other sensitive populations near the storage site.

Following his presentation, participants asked the following questions:

> *How were the areas calculated for the estimated AoRs in your exercises? Why do the areas increase slightly?*
> The AoRs were generated using simple radial flow estimates. The areas increase as the estimated quantity of CO_2 generated from sources increases and as the later, less ideal storage sites are used.
>
> *What is a typical radius of the AoR?*
> This would largely be driven by the size of the facility and the amount of CO_2 generated. For a large coal fired power plant or a large coal-to-liquids facility, plume radii could be on the order of several kilometers for each of several wells implying an AoR area of tens of square kilometers.

Teapot Dome Field Experimental Facility: Characterization of a Century-Old Oil Field for CO_2 Injection, Part II: Anthropogenic Features

Vicki Stamp, DOE Rocky Mountain Oilfield Testing Center, expanded on Mark Milliken's Session 1 presentation to discuss the impact of anthropogenic features on the appropriateness of the Teapot Dome facility. The site, if geologically suitable, offers an adequate infrastructure, has a good database of site information, is completely owned by the government, and has the support of several industrial partners. In one area of the site there were so many abandoned wells that the area was ruled out for possible injection because of the anticipated expense to plug and abandon the wells. The general site can provide information that is applicable to geologic analogues in about 18 states. Ms. Stamp described a variety of site characterization and reservoir screening tests underway, including fluid testing, EOR simulations, modeling, soil gas/gas flux assessments, fault seal assessments, well bore/cement integrity studies, and magnetic and seismic surveys. Results to date indicate that the Tensleep Formation at the site appears to be a good prospect for research on GS and monitoring.

No questions were raised after Ms. Stamp's talk.

Methodology for Determining the Use of a Fixed Radius AoR or Zone of Endangering Influence (ZEI) When Conducting an AoR Analysis for UIC Operations

Steve Platt, U.S. EPA Region 3 described the drinking water protection standards in the Safe Drinking Water Act (SDWA) and the federal UIC regulations. He also described the process that Region 3 uses to calculate AoR, particularly the usefulness of calculating a zone of endangering influence (ZEI) vs. using a fixed radius AoR. Mr. Platt emphasized that the use of a fixed radius AoR would only be appropriate if it is protective of USDWs, as mandated under the SDWA and UIC regulations. He concluded by presenting an example of a ZEI calculation at a Class II EOR project in Taylorstown, Pennsylvania.

A participant asked the following question of Mr. Platt:

> *Where in the field should monitoring wells be placed?*
> Monitoring wells should be placed near locations where abandoned wells are suspected. About 15 wells are in place at the Taylorstown site in Pennsylvania; they are located between the new injection wells and the suspected location of the unplugged/abandoned wells. This is to allow for the earliest possible indication of changes in formation fluid level before fluids could potentially rise upwards through the abandoned/unplugged well.

Following the presentations, breakout group participants offered input on calculating the AoR for GS sites:

Is a fixed radius AoR appropriate for CO_2 GS, or should the AoR be based on calculations similar to those used to determine the ZEI?

- A fixed radius is not appropriate. The AoR size determination should be based on models. There are two AoRs to consider: the extent of elevated pressure and the extent of the CO_2 plume.

- The AoR calculation for a buoyant gas will differ from calculations based on traditional (liquid) models; however, it is possible to use methods that reflect equivalent liquid volume.

- Perhaps review and adapt permit conditions based on monitoring results.

- Experiences of the natural gas storage industry may provide useful insight.

How do CO_2 injection volume, rate, and pressure affect the size and shape of the AoR?

- Models are needed to answer this question. These factors (e.g., injection volume, rate, pressure) are standard model inputs and models are available. (Note also that the size and shape of the AoR is affected by what time frame the calculations are to address.)

- Fingering effects and reservoir heterogeneity must be considered, although it is likely that some fingering effects would not be of adequate scale to be characterized or to be of concern regarding the AoR.

- Dissolved CO_2 and displaced brine are less important considerations. The dissolved CO_2 is more dense/less buoyant, and therefore is less of a problem.

- Consider the possibility that the definition of a USDW may change; what is not defined as a drinking water source today may be considered as such in the future as water scarcity concerns expand. Likewise, advances in mining technology may change the definition of an "unmineable coal seam."

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

- Yes; however, given perceived relative potential impact/risk considerations, the pressure front could possibly be monitored in less detail or less rigorously than the CO_2 plume.

- Studies must consider regional and adjacent reservoirs and regional pressures. Multiple operators can affect reservoir conditions and therefore long-term predictability/certainty of storage.

- Given that there will be multiple injection wells, well spacing is a concern.

- Consider temporal and spatial effects. When injection is complete, pressures may drop (although the period of over-pressurization could last a while).

How do subsurface features (trap mechanisms, migration pathways, or heterogeneity/ facies changes within the injection zone) affect the AoR?

- Gross-scale predictions are possible, but details (e.g., fingering effects) are more difficult to determine. 3-D seismic surveys can give some details (e.g., identify pooling of CO_2, etc.), but are not perfect and are expensive. Canada has been successful with 4-D seismic/monitoring; this may be appropriate to validate models.

- Review Class I experiences with modeling of injectate plumes; these models could be useful to predict details of flow/migration.

- Review Australian/North American studies of possible analogues for how natural gas traps behave and contain CO_2.

- Trapping mechanisms need to be built into models.

How does the two-phase nature and buoyancy of the injected CO_2 affect AoR studies?

- Two-phase analog models exist (e.g., LANDMARK).

- It is not appropriate to assume that geological features that trap water and oil would also trap CO_2.

Are existing AoR study methods, formulas, and models adequate for determining the AoR for CO_2 GS sites (e.g., saline aquifers, unmineable coal seams, and depleted oil and gas reservoirs)?

- Modeling will be an important tool. Research is needed on what models to use, appropriate scale/complexity, margin of safety, and validation/calibration methods.

- Existing AoR calculation methods will not be applicable to coal seams.

- Existing single-phase models for liquid injections are not appropriate for CO_2.

How many details are needed for models applied to AoR studies (e.g., for model calibration and sensitivity analysis)?

- Expert evaluation and review of the applicability of existing models to CO_2 GS may be needed.

How would the AoR for horizontal CO_2 injection wells be determined?

- The potential use of horizontal wells might add complexity, but vertical well models can basically be used for horizontal wells with some modification and appropriate (different) inputs. The AoR is based on the reservoir, not the well. Research and data may be available from the In Salah project and the oil and gas industry.

What research is available to determine appropriate timeframes (i.e., decades vs. centuries) for modeling the AoR for CO_2 GS sites?

- The Intergovernmental Panel on Climate Change (IPCC) report cites a 1,000-year timeframe for CO_2 retention (though this reportedly might be for a more general consideration and not a site-specific prescription). The capture zone of concern should reflect a time range of 100 to 10,000 years.

- The answer may depend of the predictive ability of the models.

- Models can only predict movement in a static reservoir; what about future or reactivated injection?

- Models should be verified based on post-injection monitoring.

Session 3: Addressing Wells in the Area of Review

The first session of Day 2 focused on what factors affect the size and shape of the AoR and what corrective or mitigating actions are needed to address active and inactive wells in the AoR.

The Role of Existing Wells in Projecting Performance Standards for Engineered Saline Reservoirs: Examples from the Gulf Coast

Ian Duncan, from the Bureau of Economic Geology at the University of Texas at Austin, stressed that a regulatory framework for GS of CO_2 needs to be performance-based, flexible, and adaptive to provide the ability to "learn by doing," because much of the important geologic and technical information will only become available when large industrial scale sequestration operations are underway. He advocated region-wide assessment of CO_2 sequestration sites, partly because existing AoR considerations do not adequately address large-scale CO_2 injection that will create a zone of elevated pressure extending much beyond the actual CO_2 plume. Regarding potential sequestration in areas with very large numbers of abandoned and active wells, Dr. Duncan noted that the substantial CO_2 storage capacities provided by saline reservoirs typically lie beneath (i.e., much deeper than) well penetrations, even in heavily drilled areas. The role of faults was also discussed; while some open faults could be conduits for CO_2 leakage, sealed faults have proven to be fairly common containment features in oil and gas reservoirs. Dr. Duncan added that MMV should be an important, integrated part of permitting for CO_2 sequestration operations.

Following Dr. Duncan's presentation, participants had the following comments and questions:

> *Your suggestion to avoid salt domes for GS seems contradictory to their being proven oil reservoirs and targets for exploration.*
> There are a lot of oil wells around salt domes, which would not be good for CO_2 storage; in addition, new imaging and seismic methods are finding oil deeper around salt domes. Oil extraction and CO_2 storage would be competing resources, and if oil exploration is being pursued around salt domes, it is important that GS does not compete.
>
> *Have caverns within salt domes been studied as possible GS sites?*
> Studies have been done; however, salt caverns are not believed to be useful, because they are shallow and porous and supercritical CO_2 would be highly expandable in this type of environment.
>
> *Would basin-wide permitting reduce the permitting expenses for specific projects or create extra bureaucracy?*
> A general permit would reduce the redundancy of effort associated with AoR studies for individual projects in the same basin.

Are regional permits applicable to oil and gas reserves?
No, general permits are mostly applicable to saline aquifers; their use would be on a case-by-case basis.

Relevance of Geological Carbon Storage Capacity Assessments to AoR Studies

Sean Brennan, US Geological Survey, began his talk by observing that CO_2 storage volume is a finite resource that will be consumed by CO_2 geologic sequestration. He discussed how "specific storage volumes" (SSVs) can be used to calculate the "footprint" of a CO_2 plume, and thus estimate the size of the AoR. SSV refers to the volume of a target formation per unit mass of CO_2 injected; they vary with temperature and pressure of the CO_2. Dr. Brennan provided some example SSV calculations for the 1,100 MW Laramie River (WY) power plant. Based on assumed temperature and pressure, the sandstone formation studied is estimated to have the capacity to sequester 50 years' worth of CO_2 emissions from the plant. The calculated footprint is equivalent to the size of a very large oil field (for which equivalents exist in the U.S.). He identified that many of his simplifying assumptions (perfect saturation, perfectly filled injection zones) are probably unrealistic. Because petroleum and CO_2 behave similarly in the subsurface, traps that have contained petroleum on geologic time scales (some for as long as 300 million years) may be ideal storage sites for CO_2. Dr. Brennan also provided some examples and experiences from the Ellenberger Fields in Texas and the Rangeley Field in Colorado.

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

How were the estimates for cap leakage made?
They were based on observations and/or monitoring.

Couldn't SSV increase by orders of magnitude, depending on the conditions?
Yes, the modeling exercise estimates a minimum foot print (which is large).

In the Ellenburger Fields study, how was the date of CO_2 storage determined?
It was the only historic event at the site.

The Effect of CO_2 Sequestration on Wells in the Area of Influence

Andrew Duguid, Schlumberger Carbon Services, initially pointed out that the CO_2 properties of density and viscosity make it more similar to natural gas then to oil or water, and then reviewed some of the questions and issues related to corrective action for wells near GS sites and the effect of CO_2 injection on well materials. Dr. Duguid presented various considerations related to addressing wells in the AoR, including:

- Cement additives, such as bentonite, that require an increase in the water-to-cement ratio, should be avoided because this can accelerate cement degradation.
- Fields with large numbers of artificial penetrations need not be excluded from consideration as GS sites; however, they do pose additional risk for leakage which must be addressed.

- Corrosion of cements appears to occur much more slowly in the field than in laboratory experiments.
- CO_2 can corrode well materials. However, there needs to be a flow of CO_2 in the area of the wellbore to create significant corrosion, yet such flow conditions are less likely.
- It is important to verify that wells in the AoR were abandoned properly.
- The potential existence and location of undocumented (or lost) wells in the AoR can be a concern; field surveys may be needed to identify these, particularly in oil and gas fields.

He concluded by adding that some portions of the UIC regulations may need to be more specific to address concerns related to CO_2 injection.

No questions were raised after Dr. Duguid's presentation.

Following the presentations, breakout group participants offered the following input on addressing wells in the AoR:

How do the properties of CO_2 for GS (e.g., corrosivity, buoyancy, or the presence of impurities) impact wells in the AoR and appropriate corrective actions?

- Research on geochemical reactions is needed. Study long term acid gas effects (e.g., from CO_2 with H_2S) (Alberta Energy and Utilities Board). Look into research on the geochemistry of more complex injectate streams (of CO_2 plus impurities) and how they react with the wells and cement. Also look at how CO_2 may mobilize residual hydrocarbons (Frio) or metals, and pH drops from CO_2 degradation of carbon-steel cements.

- Look at the pressure front beyond CO_2 plume. Studies of hydrocarbon movement may be applicable. Is the extent of the CO_2 plume or the area of elevated pressure/pressure front more relevant to the size of the AoR? There may be concentric zones of decreasing concern around injection wells; the zone of more concern is nearer the injection wells where the plume and higher pressures are found while farther from the injection well of concern is less because it would be beyond the plume, have lower pressure, and buoyancy rather than pressure would influence the system.

- Buoyancy may be a concern, CO_2 may pool at the top of injection zone near caprock.

Are existing UIC Program requirements for corrective action sufficient?

- Examine what intervention or pre-corrective techniques are available. For example, techniques exist to change gradients or create boundaries to prevent CO_2 from moving into shallow formations.

- Corrective action requirements should be performance-based; EPA should make information on techniques available and place the burden of proof on the applicant. EPA may need to develop a set of recommended practices.

- Some leaks may be acceptable, especially if there are multiple barriers and buffers. Mitigation efforts should be focused on wells with identified leaks, especially near injection/high pressure zones, monitoring results should dictate which remaining wells to remediate.

- Monitoring (especially in the upper zones) may be more appropriate than extensive well mitigation. Consider only mitigating those wells with identified leaks, rather than all/most/many wells in the AoR. However, some field experience shows that even when leaks are detected, it is sometimes difficult or impossible to identify which well(s) are the source of a leak. Perhaps add an odorant to the CO_2 (as is done with natural gas).

- Regulatory text specific to CO_2 injection may be needed.

What types of cement/additives are appropriate for corrective action on abandoned wells?

- For properly constructed wells, current corrective action techniques should be adequate. However, CO_2 can corrode traditional Portland-based cement, and wells with pre-Portland cements may be a concern.

- The lack of availability of API-type cement may be a problem.

- Look into research by the CO_2 Capture Project.

- Laboratory versus field results: conditions in the laboratory are more extreme and may not reflect what is happening in the field.

Are any additional corrective actions needed for "properly" abandoned wells (i.e., with traditional carbon steel and Portland cement) to address the corrosive nature of CO_2 and any associated impurities?

- What tests and tools are available to determine if wells were actually properly abandoned, e.g., the condition of cement? The oil industry has tools that can measure pressure in wells. Some wells are inaccessible.

- Flowing conditions can shorten the casing life span. This has an impact on whether additional corrective action may be needed.

- Research is needed on tools that can detect very small avenues of leakage (channels), e.g., logging tools, cement evaluation tools, temperature logs, acoustic log, or tracer tests. No existing technology can detect cement integrity perfectly.

How have older wells with older plugs held up to CO_2 injection underneath or nearby?

- There is a general lack of data, because abandoned wells are not being stressed by current injection practices. Look at modern projects (e.g., In Salah and Sleipner) and natural gas storage wells.

- Old wells (based on older technology) are likely to leak first, usually due to poor cement pouring rather than cement degradation; however, most CO_2 injection would be to deeper zones, and therefore likely below (deeper than) older wells which tend to be more shallow.

- Can cement job imperfections potentially correct themselves or do they get worse? Studies are currently being conducted on this. Review the "well autopsy" studies being conducted on old wells to check cement work/quality.

- Different standards/practices may be appropriate for different well types. For example, cement standards for Class II wells (60 percent cement) differ from those for Class I wells (80 percent cement); also injection wells differ from producing wells.

- At Salt Creek, they had to remediate almost every well in the field: perforate and squeeze. It would be good to somehow look at routine well operations and what has happened with well materials at Salt Creek (CO2/EOR) as well as SACROC (CO2/EOR), Sheep Mountain (CO2 production), and Hutchison, KS (gas migration)

Are shallow wells in the AoR (e.g., drinking water wells and wells not penetrating the confining layer) of concern given the buoyant nature of CO_2? What about other "natural conduits" for fluid movement identified in the AoR?

- Shallow wells could be a concern depending on where the CO_2 is moving; this also depends on well's location/use and the integrity of confining layers. It is important to at least know where the shallow wells are.

- Baseline sampling (especially of drinking water wells) is important both to detect problems and establish a baseline for MMV.

Should fields with large numbers of active or abandoned wells generally be considered unsuitable for CO_2 geosequestration?

- The presence of large numbers of wells does not necessarily imply outright unsuitability; however, extra care is warranted.

- Much depends on the location and depth of the abandoned wells. If CO_2 is injected into deep formations, there may not be a conflict.

- Competing/conflicting activities may be more of a concern than the presence of the wells.

- Research in TX indicates that substantial CO2 storage capacity in deep saline reservoirs is likely deeper, and sometimes much deeper, than most existing well penetrations. This research also indicates that, generally, the abandoned wells of poorer quality tend to be older and shallower (with deeper wells tending to be more recent and of better quality materials, better abandonment techniques, better locational records, etc.).

How would the volume of CO_2 injected affect corrective action needs or requirements?

- Consider both pressure and volume effects; determine how much pressure increase is acceptable.

Perspectives from the Field

Panelists representing DOE's Regional Carbon Sequestration Partnerships and the IOGCC presented permitting experiences related to geological and artificial features in the AoR and corrective action.

George Koperna and **David Riestenberg**, Advanced Resources International Inc., described the permitting efforts at the SECARB Partnership's Mississippi Test Site. The purpose of the project is to identify and test a GS site near a large coal-fired power plant in the southeastern U.S. The selected site offers several trapping mechanisms and relatively few wells in the area (and none within 2 miles of the proposed injection well). Mr. Koperna described the efforts to study the regional geology and select a site; performed the needed National Environmental Policy Act (NEPA) evaluations; drilling permit; UIC permits and financial assurance documentation; and conducting public outreach. SECARB plans to drill the injection well in September or October 2007 and begin injection in 2008.

Nino Ripepi, Virginia Center of Coal and Energy/Virginia Tech, spoke about the SECARB Partnership's sequestration projects in the Central Appalachian Basin and Black Warrior Basin of southwestern Virginia, where CBM extraction offers financial incentives for sequestering CO_2. At the Black Warrior site, a production well is being converted to an injection well. Following injection into three coal zones, project staff will monitor pressure and conduct tracer studies and soil surveys. The injection site has been selected and the permitting process is underway; injection is scheduled to begin in early 2008.

Larry Bengal of the Arkansas Oil and Gas Commission spoke on behalf of IOGCC, and provided some brief statistics on state orphaned well programs. All 30 oil and gas producing states have programs in place to plug orphaned wells. Wyoming began the first program in 1951; most other states initiated similar programs in the 1980s and 1990s. To date, these programs have spent $149 million to plug 27,931 wells; plugging of another 55,000 wells is pending. There are an estimated 96,000 orphaned wells for which no operator is on record and whose condition is unknown; this is a potentially big concern. Approximately $27 million is available in state orphaned well programs to address these wells.

Rob Trautz, Lawrence Berkeley National Laboratory, described activities by the WESTCARB Partnership to select a site and obtain a permit for the Rosetta Resources pilot project in California. Selecting the site involved several challenges, including land ownership and Endangered Species Act issues. Mr. Trautz added that, while certain aspects of the permitting process have benefited from available tools (e.g., EPA's Class V permitting guidance and tools and models for AoR calculation), other aspects such as public acceptance, pore space ownership, and liability concerns provide challenges.

The audience asked the following questions of the panelists:

What are the goals of the injectivity testing at the Mississippi Test Site?
George Koperna replied that they plan 8-12 hours of injection, followed by a shut-in for about 24 hours. They will then collect pressure data and model the CO_2 flood front.

Has IOGCC addressed long-term liabilities and impurities in their model regulations?
Larry Bengal responded that IOGCC proposes that liability would be a state function. Bond funds can be used for a certain period initially and then trust fund will be used for MMV and long-term care. Regarding impurity levels, a 95 percent CO_2 concentration is assumed for GS operations and such purity may be changed according to the regulated standard

How was SECARB able to characterize the Tuscaloosa Formation, given its heterogeneous nature?
Mr. Koperna replied that the Tuscaloosa massive sand is a basal sand with 5 or 6 shale breaks. It is possible to say, at a regional scale, that there are multiple vertical migration barriers; information is still being gathered.

Do any of the partnerships plan to employ any new well materials or unique construction at the test sites?

- Rob Trautz replied that this is not likely at the WESTCARB site, given the short life span of the Rosetta project.

- Mr. Koperna added that, at the Mississippi site, they plan to use low-water cement and nickel/carbon steel casing; he added that the injection and monitoring wells will be turned over to the plant when the test is complete.

- Nino Ripepi said that they plan to convert a production well to injection; the selected production well at the Virginia site is basically finished as an open hole.

Have either of the SECARB sites encountered any competing interest (e.g., with oil or coal exploration)?

- Mr. Ripepi said that in coal regions, people question what is considered “mineable.” Most planned CO_2 injection will be outside of active coal mining areas, in areas where the coal seems are deep and thin and where new technology would be needed to mine the coal. He added that it will likely be the owner’s decision whether to use a specific location for CO_2 storage.

- Mr. Koperna replied that GS is planned in active oil production and EOR areas, but at a sufficient distance to eliminate impacts and avoid conflicts.

Who owns the pore space for GS projects?
Mr. Bengal said that this can vary based on state property laws. Mr. Koperna added that, in Mississippi, the answer depends on whether the CO_2 is being considered a commodity or a waste.

Next Steps/Closing

Ann Codrington, OGWDW, closed the workshop by thanking the speakers and participants for their valuable input, and added that EPA will take everything discussed in the workshop under consideration as it develops a 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. A workshop on MMV will be held in the fall; all participants will be notified as plans are developed.

ATTACHMENTS

1. Workshop Participants
2. Workshop Agenda
3. Presentations

Attachment 1: Workshop Participants

James Anderson, Shell E&P
Scott Anderson, Environmental Defense
Lawrence Bengal, Arkansas Oil and Gas Commission
Jens Birkholzer, Lawrence Berkeley National Laboratory
Kevin Bliss, IOGCC
Glenn Breed, Wyoming Department of Environmental Quality
Sean Brennan, U.S. Geological Survey
Valerie Chan, US EPA
Ann Codrington, US EPA, OGWDW
Karen Cohen, US Dept. of Energy/NETL
Michael Costello, Shell Exploration and Production
Casie Davidson, Pacific Northwest National Laboratory
Dominic DiGiulio, US EPA, ORD
Jim Dooley, Pacific Northwest National Laboratory
Cynthia Dougherty, US EPA, OGWDW
Michael J. Ducker, Department of Energy
Andrew Duguid, Schlumberger Carbon Services
Douglas Duncan, U.S. Geological Survey
Ian Duncan, Bureau of Economic Geology, UT Austin
Mark Fesmire, New Mexico Oil Conservation Commission
Robert Finley, IL State Geological Survey
Theodore Fritz, EPA Region 7 WWPD/DRWM
Marilyn Ginsberg, US EPA, OGWDW
Brian Graves, US EPA Region 6
Katherine Hamner, The Cadmus Group, Inc.
Kevin Healy, Bryan Cave LLP
Steve Heare, US EPA, OGWDW
Allison Herring, Kansas Corporation Commission
Scott Imbus, Chevron Energy Technology Co.
William Jones, State of New Mexico, Oil Conservation Division
Peter Jordan, Subsurface Technology, Inc.
Bob Kane, USDOE
Anhar Karimjee, US EPA, OAP
Ray Kelly, Edison Mission Energy
Suzanne Kelly, US EPA, OGWDW
Badr Kharusi, Shell Exploration & Production International
Christian D. Klose, Columbia University
Bruce Kobelski, US EPA, OGWDW
George Koperna, Advanced Resources International, Inc.
Jonathan Koplos, The Cadmus Group, Inc.
Doug Louis, Conservation Division, KCC
Brian McLean, US EPA, OAP
Stephanie Meadows, API
Mark Milliken, DOE Rocky Mountain Oilfield Testing Center

Rich Moen, SIEP, Inc.
Greg Monson, Shell Exploration and Production Company
Philip Papadeas, Sandia Technologies, LLC
Michael Parker, ExxonMobil Production Company
Rajesh Pawar, Los Alamos National Laboratory
Joel Peterson, Errol L. Montgomery & Associates, Inc.
Stephen Platt, US EPA Region 3
Theresa Pugh, American Public Power Association
Dave Rectenwald, US EPA Region 3
David Riestenberg, Advanced Resources International
Shari Ring, The Cadmus Group, Inc.
Nino Ripepi, Virginia Center for Coal and Energy Research
Kaylene Ritter, Stratus Consulting
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John Venezia, World Resources Institute
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Lee Whitehurst, US EPA, OGWDW
Richard Wilkin, US EPA, ORD
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