Will Water Issues/Regulatory Capacity Allow or Prevent Geologic Sequestration for New Power Plants?

A Review of the Underground Injection Control Program and Carbon Capture and Storage

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Executive Summary

International concern over global climate change has spurred a search to identify ways to reduce greenhouse gas (GHG) emissions. Of the six gases comprising greenhouse emissions, carbon dioxide (CO_2 – "carbon") emissions far exceed the other five in the amount emitted.[1] The U.S. is considering a number of voluntary options for an 18 percent reduction in CO_2 emissions by the year 2012. One technology receiving serious consideration by the international agencies, Congress, states, and the Bush Administration is carbon capture and storage (CCS) or sequestration[2]

First the carbon dioxide from a power plant would have to be separated and removed from the power plant. Carbon sequestration really refers to the geologic storage in deep geological formations below the earth's surface. Carbon dioxide injection has been used for several years in enhanced oil recovery operations. Through government and private partnerships, the U.S., through the Department of Energy (DOE), is evaluating the viability of long-term CCS by conducting demonstration and validation testing of CCS pilot projects. APPA supports carbon storage demonstrations through the DOE and FutureGen to determine if the injection of CO_2 is safe and effective as a mitigation measure.

The CCS issue is of considerable import to the electricity/power plant sector which the U.S. DOE considers to be one of the largest emitters of CO_2, accounting for 38 percent of CO_2 emissions among all energy sectors.[3]

While the U.S. DOE is pushing aggressively to deploy CCS for full-scale commercial use, there are a number of technical, regulatory, and policy issues related to long-term CO_2 storage or geosequestration that remain to be studied and resolved.

The U.S. Environmental Protection Agency (EPA) has regulatory authority over injection of wastes into wells through the Underground Injection Control program (UIC) created by Congress under the Safe Water Drinking Act. Congress specifically created the program out of concern for the protection of underground drinking water sources. Although the UIC program has established five classes to address various injection well activities, the Agency currently does not have a regulatory framework by which to regulate CCS activities. U.S. EPA has recently issued guidance to assist its regional offices and state regulators with permitting and operational decisions related to CCS pilot projects.

The U.S. EPA has classified CCS pilot projects as Class V experimental technology; however, the regulatory framework for Class V wells is insufficient to provide the necessary safeguards to ensure protection of groundwater sources. Therefore regulators have relied on the stringent requirements established for Class I hazardous waste wells, which includes the requirement that operators demonstrate no-migration of injection fluids (which would include CO_2) for a period of 10,000 years.

[1] U.S. DOE National Energy Technology Laboratory, *Carbon Sequestration Program Environmental Reference Document ("NETL Reference Document")*, Aug. 2007, at 1-2. See also, Electric Power Research Institute, *Electricity Technologies in a Carbon-Constrained World*, ("Electricity sector is responsible for 1/3 of U.S. CO_2 emissions").

[2] Sometimes sequestration is also referred to as geosequestration.

[3] *NETL Reference Document*, at 1-2.

In summary, there are major limitations in the technical, regulatory, and administrative requirements of the UIC program that appear to preclude, in the short term, commercial-scale sequestration of carbon in non-oil and gas sites in large parts of the country. These limitations are important for utilities and policy officials to evaluate as they consider CCS projects. For electric utilities that wish to build additional generation to meet the needs of their communities, the challenges include very difficult issues.

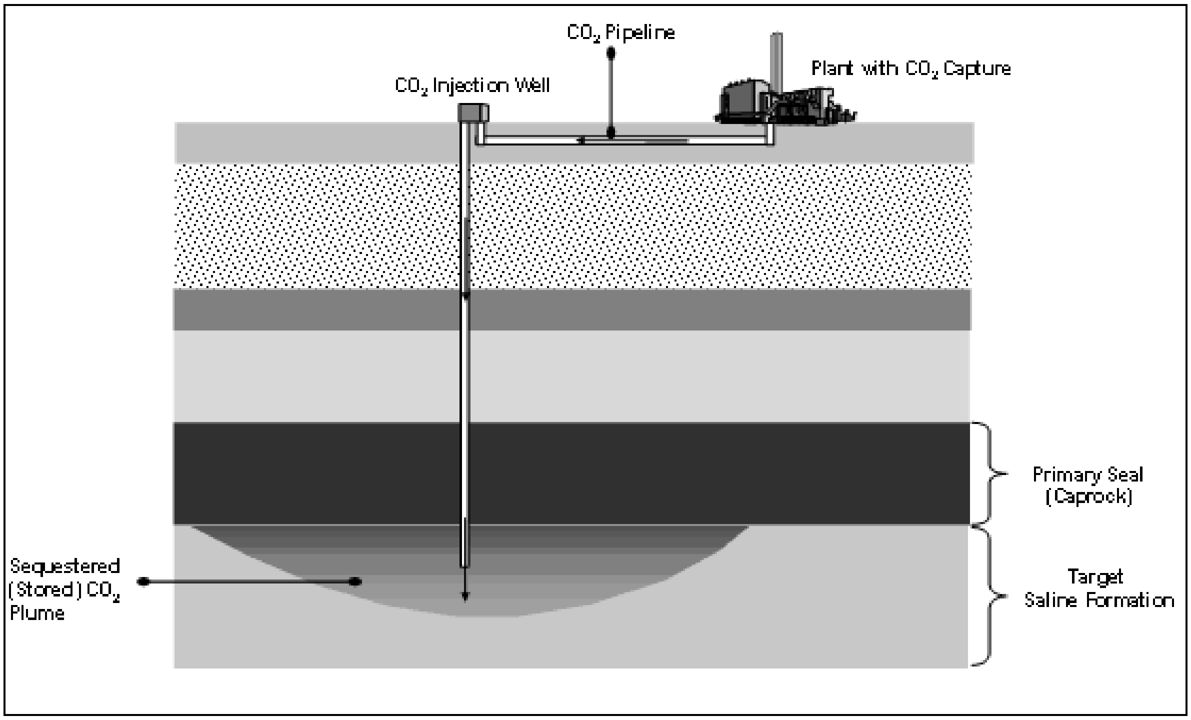
APPA recommends that States and Public Utility Commissions consider and investigate the several limitations identified in this paper prior to mandating CCS as a part of permit approval. APPA also recommends working with the U.S. EPA on the cross-cutting and multimedia regulatory issues as the Agency moves forward towards determining the best regulatory framework for CCS.

Introduction

What is the Issue and Why does it Matter to Utilities and Municipal Government?

Policy officials and scientists alike, searching for viable ways to reduce carbon dioxide (CO_2) emissions, have identified carbon capture and storage (CCS) [4] as a promising technology. This technology separates CO_2 from emissions of large stationary sources like power plants and injects the captured CO_2 deep into the earth. Figure 1 gives a simple picture of this technology. The Intergovernmental Panel on Climate Change (IPCC) has identified CCS as a way of achieving overall reductions in greenhouse gas emissions.[5] This enthusiasm is shared by the U.S. government. The U.S. Department of Energy (DOE) is engaged in research and development of various CCS technologies to determine the viability of full scale deployment of CCS by the year 2012. The U.S. DOE is leading the Regional Carbon Sequestration Partnerships to conduct research and development of CCS and supporting small scale demonstration and validation pilot projects to determine the potential of this technology.

Figure 1: Diagram of a Carbon Capture and Storage Operation[6]



The benefits of reducing CO_2 emissions through CCS must be balanced against the potential increased risks of groundwater pollution from CCS. Utilities provide water and power to their

[4] Carbon Capture and Storage is also referred to as Carbon Geologic Sequestration.

[5] Intergovernmental Panel on Climate Change, *Special Report: Carbon Dioxide Capture and Storage, Summary of Policymakers, 2005.*

[6] U.S. DOE National Energy Technology Laboratory, *Carbon Sequestration Program Environmental Reference Document*, Aug. 2007, at 3-53 Fig. 3-22.

communities and rely on available water supplies to produce power. Utilities are uniquely positioned and therefore must understand the potential promise and limitations of CCS.

The potential trade-offs will tighten in the future as demand increases for power, water, and GHG reductions. According to EPA, ground water systems account for 91 percent of the total public drinking water systems in the U.S., serving 36 percent of the U.S. population.[7] Demand for drinking water increases with population growth, number of households, and manufacturing. While conservation has reduced this need for some new sources, groundwater levels in many parts of the U.S. are declining due to increased pumping.[8] Meanwhile, the demand for electric is expected to increase by 39 percent from 2005 to 2050,[9] requiring new capacity. If new power plants use CCS as some states are considering, underground drinking water sources will face pressure from both power and water needs.

The American Water Works Association (AWWA) and the American Public Power Association (APPA) commissioned this paper to consider the drinking water and groundwater issues with CCS and to identify the regulatory and technical hurdles that might minimize opportunities for CCS. More than 1,000 of the nation's municipalities provide electricity to homes; businesses and factories also manage many water utilities providing drinking water to residential, industrial, and commercial customers.

There are several cautions to assuming a seamless fit between current regulation and CCS. First, the existing regulations and regulatory program arose over 20 years ago, long before CCS was envisioned. Since CCS does not fit neatly into the existing program for power plants, the EPA is still in the process of crafting a regulatory approach. Second, for CCS to have a meaningful impact on U.S. emissions, the volume of CO_2 to be injected underground will dwarf current amounts by 10 to 20 times. While the nation has the ingenuity to tackle this challenge, it will require investing in technical skills, data, research, and education both in the private sector and in regulatory agencies. Currently, regulatory agencies do not have the capacity to review and permit CCS at any significant level. To illustrate this issue, this paper reviews the current UIC program, its current implementation, the current regulatory framework for CCS, and the skill shortages states and EPA will face if CCS moves toward full-scale implementation. Finally, this paper highlights the major limitations for CCS that power plant and water utility managers should consider.

What is Underground Injection?

Underground injection involves the use of simple or complex technology to inject fluids into the earth most often for purposes of waste disposal or extraction of fossil fuels and minerals. Wells regulated by the EPA include common shallow septic tank systems to highly-engineered, large volume systems that inject materials more than a mile underground. While shallow wells may only dispose of a few gallons per day, large disposal systems may each day pump the volume of an Olympic-sized swimming pool.

[7] U.S. EPA, *Factoids: Drinking Water and Ground Water Statistics for 2005*, Dec. 2006.

[8] Source: U.S. Geological Survey at http://ga.water.usgs.gov/edu/gwdepletion.html.

[9] Energy Information Administration, *Annual Energy Outlook 2007*, Feb. 2007, at 82.

What is the Underground Injection Control (UIC) Program?

Congress and EPA established the legal framework for regulating underground disposal over 30 years ago. Congress established the UIC program as part of the Safe Drinking Water Act (SDWA) of 1974 providing EPA with the authority to regulate underground injection activities to ensure the protection of the nation's underground sources of drinking water. Almost all U.S. public water systems rely on some groundwater for drinking water.[10] Congress strengthened the regulatory requirements for hazardous waste UIC disposal in 1984. In the last 20 years, there have not been significant changes to the UIC program's legal authority.

Congress intended for the UIC program to be administered by states due to the large number of wells and to the tradition of local control and regulation of drinking water. As such, the SDWA allows states to submit an application to EPA for primary enforcement or "primacy" for each part, or "class," of the program. EPA can delegate primacy to a state, U.S. territory, or a federally recognized Native American tribe. The UIC program may be executed by the EPA, the state, or both under four separate scenarios:

1) EPA administers the program for all well classes within a state if the latter chooses not to apply for primacy;
2) a state is delegated primacy for all five classes;
3) a state has primacy for Class II (oil and gas) wells only; or,
4) a state has primacy for all classes except Class II oil and gas wells.

EPA has delegated primacy for the entire program to 34 states and three territories, shares responsibility with six states, and retains full responsibility in ten states. The ten states for which EPA has primacy are: Arizona, Hawaii, Iowa, Kentucky, Michigan, Minnesota, New York, Pennsylvania, Tennessee, and Virginia. These states have determined that committing state resources to run the program is not a high priority.

How does EPA Regulate Underground Injection?

EPA established five classes of injection wells (Class I, II, III, IV, and V) under the UIC program based upon how the well is used, constructed, and operated.[11] The classes provide a consistent way for EPA to apply technical standards to similar activities to ensure the protection of underground drinking water and human health.

The classes are ranked by their potential hazard. Class I wells are for the largest volume and the most hazardous wastes. Class V wells are for shallow septic systems, dry wells, and low volume systems. Most UIC wells are either Class V, Class I, or Class II wells.

All underground injection wells must have a permit. For each class, EPA has established minimum technical standards, public participation, and a permitting process review that

[10] See EPA website, http://www.epa.gov/safewater/uic/whatis.html.
[11] 40 CFR Part 144.6.

states must include in their permitting process. With approximately 834,000 wells across the U.S.,[12] the UIC program is one of the largest environmental permitting programs.

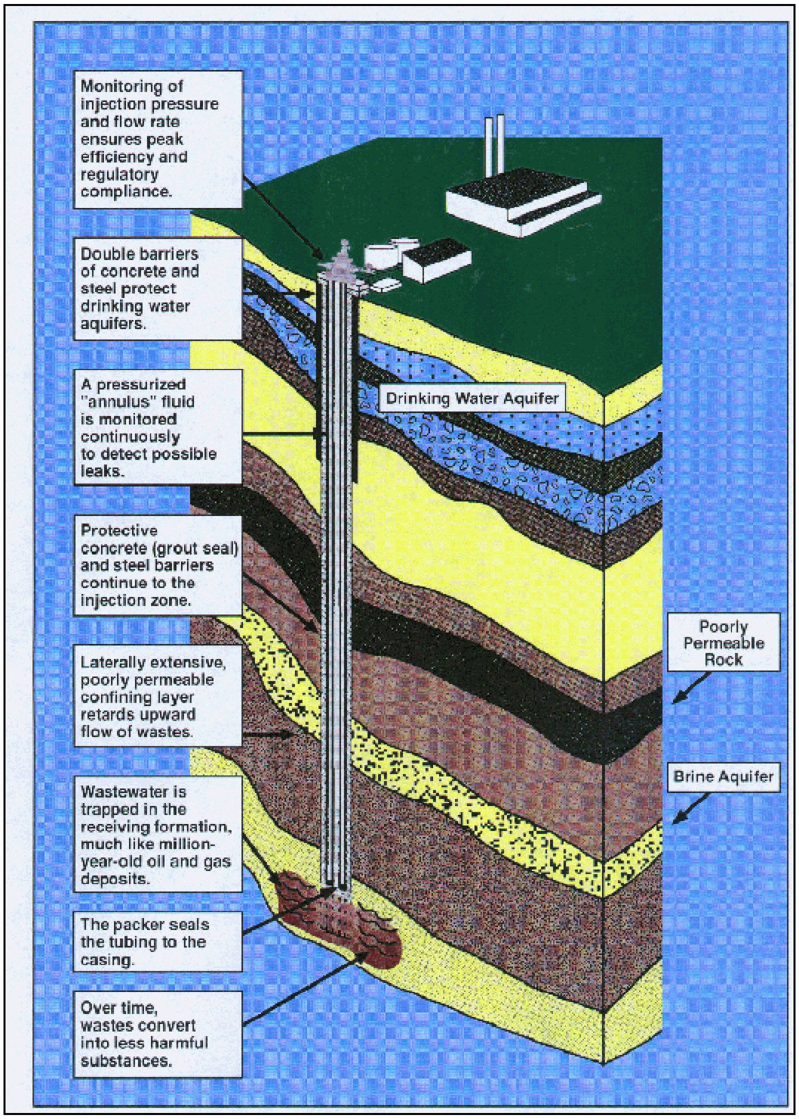
[12] U.S. EPA, *Factoids: Drinking Water and Ground Water Statistics for 2005*, Dec. 2006; http://www.epa.gov/safewater/uic/classes.html.

What are the Five Classes of Injection Wells under the UIC Program?

Class I Injection Wells

Subject to the most stringent regulations, Class I wells include industrial hazardous, nonhazardous, and municipal sewage waste. Class I wells inject wastes deep into rock formations that are located beneath the lowest underground sources of drinking water[13] and that are capped by an impermeable rock formation between the injection zone and drinking water sources above.

Figure 2: Diagram of Class I Well[14]



[13] Class I hazardous wastes are injected to depths anywhere from 1,700 feet down to 10,000 feet below the earth's surface.

[14] U.S. EPA Office of Water, *Class I Underground Injection Control Program: Study of the Risks Associated with Class I UIC Wells*, Mar. 2001, at 11.

In 1984, Congress tightened Class I requirements by instituting a no-migration standard for disposal of hazardous waste via injection and creating a petition process by which operators must obtain approval to continue hazardous waste injection operations. Specifically, Congress prohibited injection of untreated hazardous wastes unless it is demonstrated that the waste has been treated to be non hazardous or unless the waste will not migrate out of the injection zone or contaminate drinking water for <u>at least 10,000 years</u>.[15] Because of the large volume of wastes injected, Class I injection is economical if it can show a "no migration" of the waste. Well operators, filing the petition to operate such wells, must accomplish this demonstration by modeling waste behavior underground.[16]

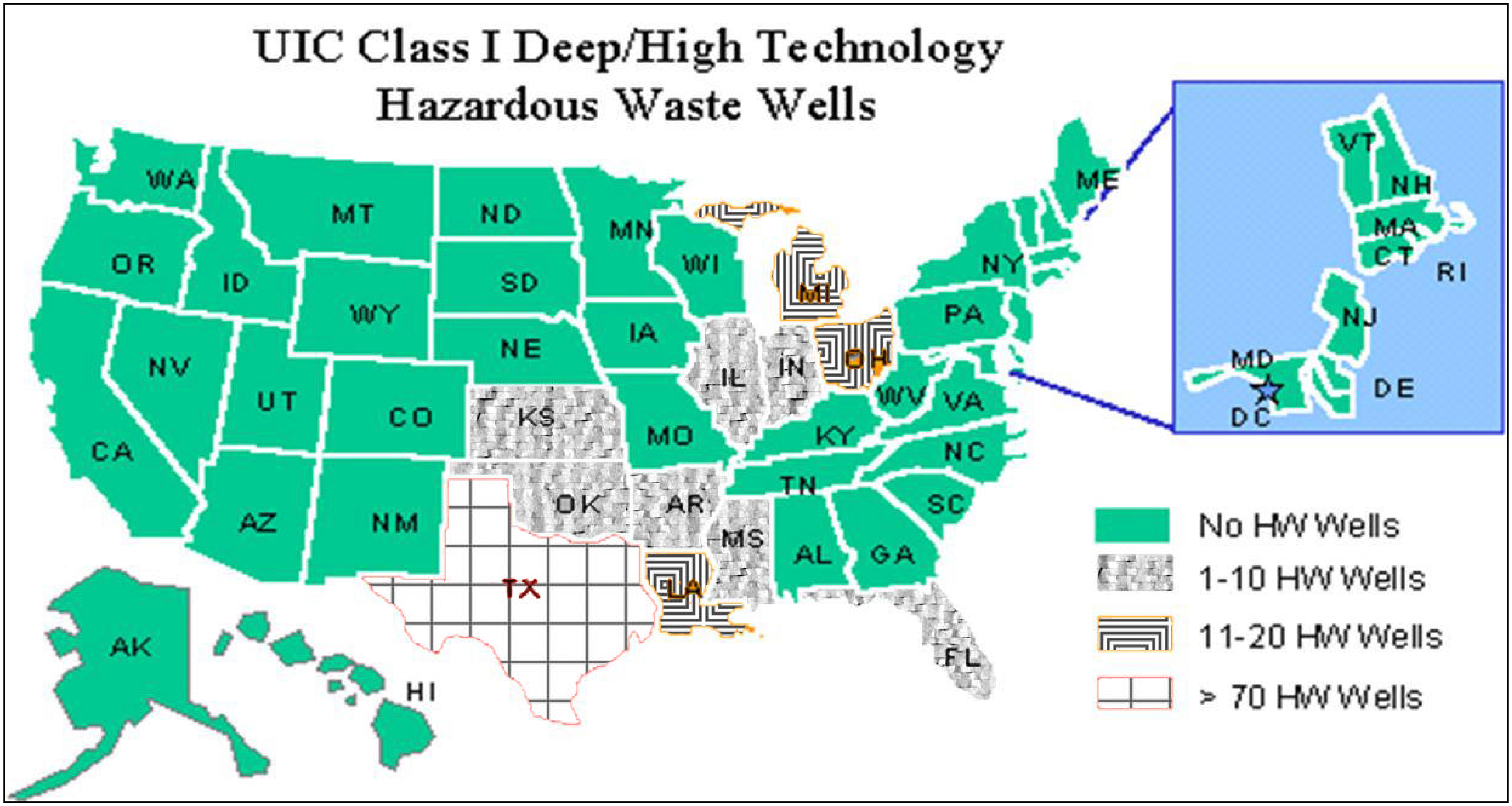
While there are a total of 529 Class I wells nationwide, there are only 163 Class I hazardous waste wells nationwide. Most Class I wells are found in Texas and Louisiana. Class I wells are banned in Missouri. The map below shows the location of Class I hazardous waste wells in the U.S.[17] As the map below shows, only 11 states have active Class I hazardous waste wells.

[15] NRDC v. EPA, 907 F. 2d at 1158

[16] RCRA, Section 3004, 40 CFR Part 148 (53 FR 28118). In the final regulations, EPA explained that 10,000 year requirement is based on ensuring for long term waste confinement. Specifically, demonstrations that can show no-migration over a 10,000 year period are likely to result in containment for an even longer period of time. Additionally, confinement for that period of time can result in waste immobilize due to geochemical transformation.

[17] See EPA website, http://www.epa.gov/safewater/uic/classi.html.

Figure 2: Hazardous Waste Wells in the U.S.



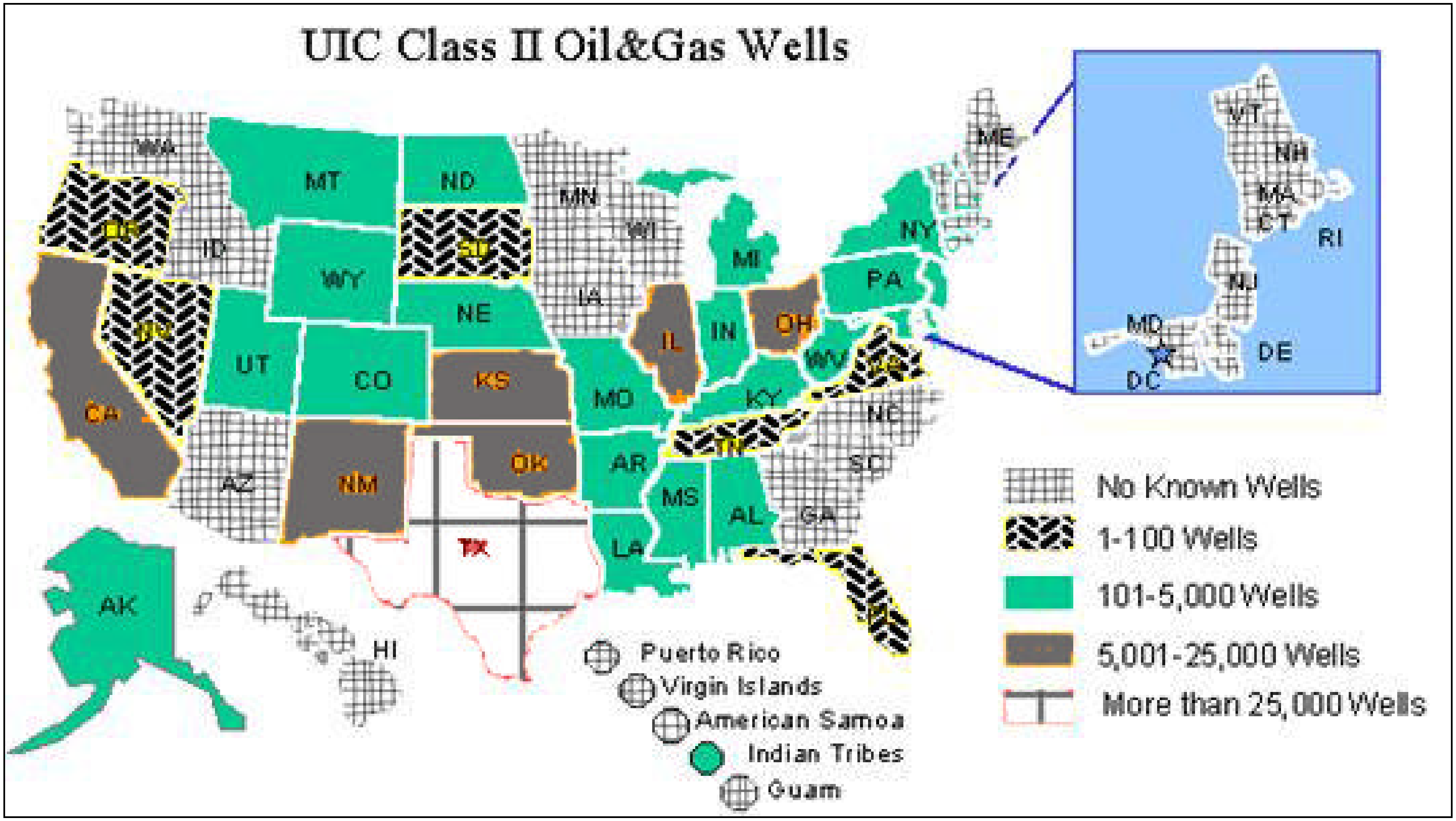
There are 366 nonhazardous Class I waste wells in 19 states. Nonhazardous Class I waste wells are required to comply with the same technical standards as hazardous waste wells.

Class II Injection Wells

Oil and gas production facilities use Class II wells to inject fluids to pump hard-to-get oil and gas deposits to the surface. The recovered crude oil and natural gas comes to the surface mixed with salty water and other impurities. States require injection of this salty water underground so as not to pollute drinking water. Class II wells must comply with strict construction and operating standards and are often similar in construction to Class I deep wells. There are approximately 167,000 Class II wells, predominantly found in the southwestern U.S. The map below shows the location of Class II wells in the U.S.[18] Twenty-two states do not have any Class II wells.

[18] See EPA Website, http://www.epa.gov/safewater/uic/classii.html.

Figure 3: UIC Class II Oil & Gas Wells in the U.S.



Class III and Class IV Injection Wells

Class III wells typically involve using injection of fluids to extract minerals. Mining operations for salt, sulfur, and uranium rely heavily on injection using Class III wells. Class III wells have minimum standards for which operators must comply, including required casing and cementing of wells to prevent the migration of fluids into drinking water sources, a prohibition on injection of fluid between the outermost casing and well bore, and required integrity tests of well casings every five years.

In Class IV wells, hazardous waste is injected directly into or above underwater drinking water. Although Class IV wells, like Class V, generally involve shallow wells, EPA created a separate class for injection activities that present a heightened risk. Class IV wells have been banned except in very narrow circumstances.

Class V Injection Wells

Most injection wells in the U.S. are Class V wells with an estimated 650,000 Class V wells in the nation.[19] Class V wells inject nonhazardous waste into or above underground drinking water and occur in a variety of residential and commercial settings including sewage disposal, aquifer recharge, and mineral recovery. Class V wells include advanced systems used by industry for wastewater disposal as well as less advanced types found in septic systems, cesspools, and agriculture drainage wells.

Injection activities that do not fit into the other classes - like CCS - are called Class V wells. Experimental technologies that are in the demonstration phase are classified as Class V injection.[20] Although there are no federal requirements that specifically address Class V experimental technology wells, over the years EPA has issued guidance to cover certain experimental technologies. Notably, EPA issued guidance in 1983 clarifying that technologies in the experimental phase which would have otherwise fallen under another UIC program-class based upon well function, may be reclassified into one of the five classes once the technology has advanced for commercial use. However, the technology remains under Class V until proven for commercial use and it is shown that the technical standards of the other class would provide sufficient protection of underground drinking water and human health once the new technology is deployed for commercial use. If the technical standards of the other classes are unable to provide sufficient protection, the new technology remains under Class V until EPA adopts protective technical standards.[21]

EPA did not establish technical standards for Class V wells until the 1990s. Because of the diversity and sheer number of these wells, EPA did not set minimal technical standards for Class V wells. Since EPA finished the Class V rule over 10 years ago, EPA has not issued major policy changes to the program.

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[19] U.S. EPA, *Factoids: Drinking Water and Ground Water Statistics for 2005*, Dec. 2006.

[20] See, Underground Injection Control (UIC) Regulations as amended, 40 CFR Part 146.05(e), Aug. 27, 1981 (46 FR 43156), and 40 CFR Part 146.03, Feb. 3, 1982 (47 FR 1416).

[21] Victor J. Kimm, *Memorandum: Appropriate Classification and Regulatory Treatment of Experimental Technologies. Ground-Water Program Guidance No. 28 (GWPG #28)*, May 31, 1983.

How Does CCS Fit into the UIC Program and Why Does this Matter to Electric Utilities?

Congress and EPA did not envision sequestration of carbon dioxide when they established the program for the chemical industry over 30 years ago so no federal regulatory framework exists to regulate CCS activities specifically. Yet, EPA has considered how CCS is regulated under the UIC program. In 2006 EPA determined that CCS activities are "underground injection" and that SDWA mechanisms are sufficient to regulate and to permit pilot projects. As a result, EPA issued a directive that CCS pilot projects are to be permitted as Class V experimental technology wells.[22] This policy directive might be supplanted by an EPA rulemaking in 2008.

Since there are no federal requirements governing Class V experimental technology wells, there has been a lot of confusion and uncertainty. In March 2007 EPA issued guidance for permitting and operation of CCS pilot projects as a Class V experimental technology wells.[23] This guidance for CCS pilot projects tries to straddle between the current legal framework and the environmental standards necessary to inject a large volume of carbon dioxide safely.

Legally, EPA confirms that Class V is "the best mechanism for authorizing pilot GS project,"[24] and that Class V general permitting and public participation requirements apply. The permits can remain in effect as long as needed to cover the timetable of project goals and may be modified or extended to alter the goals or timetable, but cannot exceed state or federal permit limits.

As a counterpoint to the flexibility inherent in a Class V permit, the guidance then lays out why states should consider more stringent permit conditions in the CCS Class V permit. EPA emphasizes throughout the guidance that protection of underground drinking water and human health is the overriding concern. EPA lays out a number of considerations for regional and state directors to take into account for purposes of permitting and operation, including:

- Siting considerations;
- Consideration of the underground area affected by the injection;
- Injection well construction;
- Injection well operation and monitoring program considerations; and,
- Site closure.

UIC program directors are also encouraged to consult with deep well experts including Class I and Class II directors to ensure appropriate standards are applied for CCS pilot projects.

However, EPA stops short of recommending CCS pilots have all the features of Class I permits, although UIC directors can opt for Class I requirements. The 2007 EPA guidance stresses that the primary goal of pilot projects is for EPA, the states, and well operators to collect and share data to better understand how CO_2 reacts and moves underground, as well as

[22] Cynthia C. Dougherty, *Letter to State Regional UIC Contacts re: CCS pilot projects*, U.S. EPA Office of Water, Jul. 5, 2006. http://www.epa.gov/safewater/uic/pdfs/memo_wells_sequestration_7-5-06.pdf

[23] *UICPG # 83*. http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf

[24] *UICPG # 83*, at 6.

understanding what the risks are associated with CO_2 injection. To determine how best to manage commercial scale CCS injection operations, the guidance suggests EPA regional and state directors adopt a more flexible approach in approving permits and identifying permit conditions to allow operators to "achieve project objectives."[25]

How have States Regulated CCS Pilots?

EPA and the states have looked to Class I and II regulations for permit conditions for CCS pilots because of the depth of injection and the larger volume of CO_2 injected. Today CO_2 is currently is being injected to recover oil and gas in wells subject to Class II well requirements. Some CCS pilots have occurred in oil and gas formations in Class II wells.[26] In the few cases to date, states have granted Class V permits for CCS pilots sequestration with many – if not all – of the technical requirements for a Class I permit.

What are the Specific Class I and II Technical Requirements?

The technical requirements for Class I and II wells include siting, well construction, operation, reporting, monitoring, permitting, financial assurance, and closure standards. The regulatory system is designed to minimize leaks into drinking water formations as waste and fluids are pumped down through these layers and after they are put underground.

Siting

Class I permits require three separate hydrogeologic investigations to permit a deep injection well: reviewing the geology of the area, conducting an area of review study, and finally submitting a no migration petition.

In the geologic study, permit applicants must show that the area is geologically stable; the area is not seismically active now and has not had earthquakes in recent geologic time. The formation must have suitable room to store the injected wastes and thick enough to dissipate the pressure without cracking the confining layer. The geologic study must also show the area around the well is free of vertical faults that could allow the injected fluids to migrate up to drinking water layers. Finally, the geologic study must also demonstrate that the injection layer's rocks are chemically compatible with the waste. [27]

The second study is the Area of Review. In this study, well operators must investigate all wells in the area that penetrate the injection or the confining layer. Operators must demonstrate that all of these wells are sufficiently capped and closed to prevent migration out of the injection layer. Under federal regulations for Class I hazardous waste wells, the Area of Review is defined as either a 2 mile radius from the well or to the zone of endangering influence on underground drinking water, whichever is a greater distance. States require larger Areas of Review; Texas, for example, uses a 2.5 radius for its Area of Review. For nonhazardous waste, the Area of Review can be a low as ¼ of a mile.[28]

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[25] *UICPG #83*, at 3.

[26] According to U.S. DOE, there are at 75 oil reserve carbon sequestration projects in the following states: Arkansas, Colorado, Louisiana, Oklahoma, and Texas. See, U.S. DOE National Energy Technology Laboratory, *Carbon Sequestration Program Environmental Reference Document*, Aug. 2007, at 3-60.

[27] U.S. EPA Office of Water, *Class I Underground Injection Control Program: Study of the Risks Associated with Class I Injection Wells*, Mar. 2001, at 18.

[28] Ibid, at 19.

One of the biggest challenges for Class I operators is to demonstrate no-migration of waste for at least ten thousand years. This demonstration requires computer modeling, knowledge of regional geology, and detailed geologic information of the area around the well. Small faults or buried channels can create a connection between deep formations and shallower drinking water sources. Injecting fluids also changes the volume and pressure underground, possibly activating dormant faults. Permit applicants must also search for abandoned wells that might connect the injection zone with upper layers.

Construction

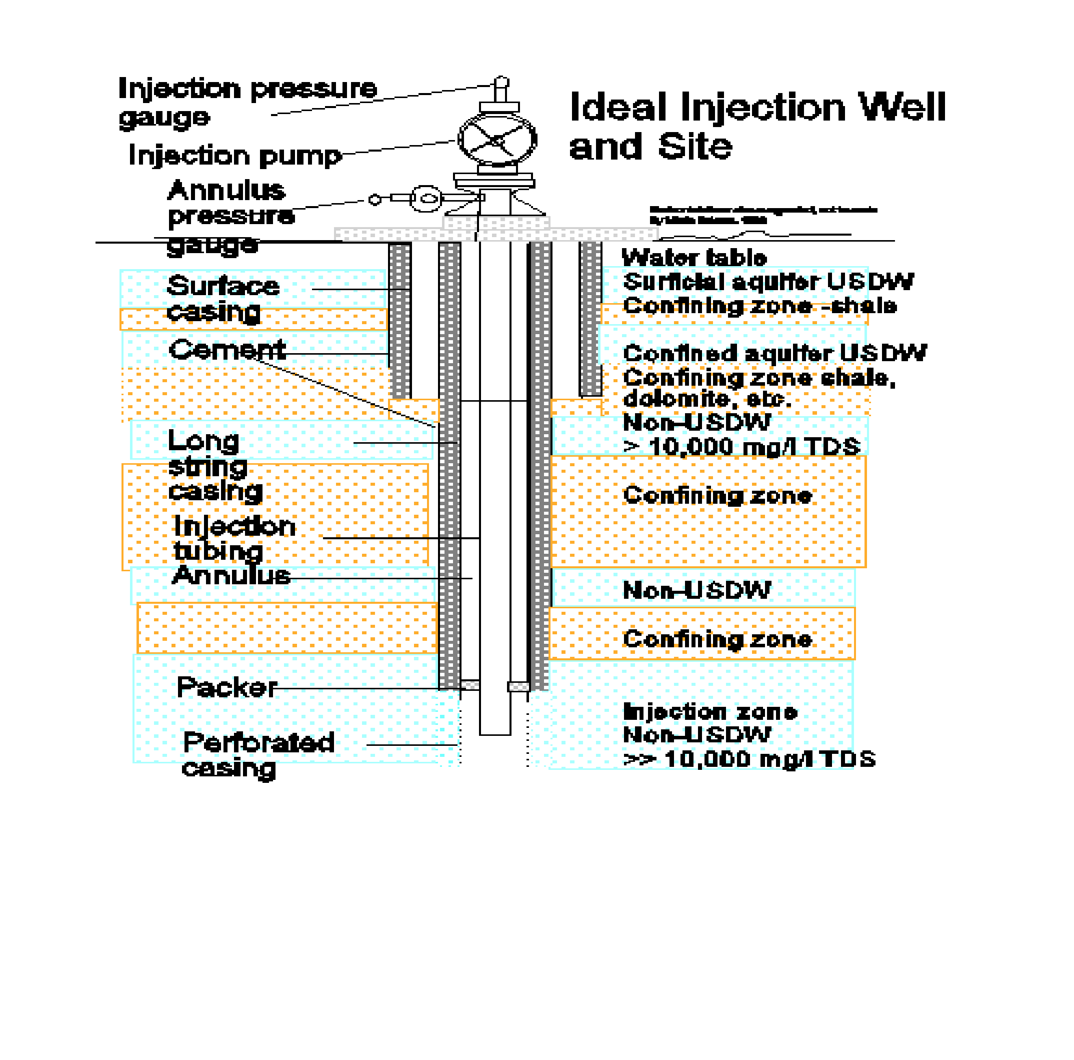
Operators prevent leaking by wrapping their wells in impermeable casing. Operators of enhanced recovery and hydrocarbon storage wells are required to case and cement the wells to prevent migration of fluids into underground drinking water. Specific casing and cementing requirements are determined by the state on a case-by-case basis; however, as part of that process they must take into account injection zone depth, depth of the bottom of all drinking water formations, injection pressures, and the nature of fluids to be injected.[29]

The well has essentially three walls so that breaching one still contains the waste. As shown in Figure 4, the injection tubing transports the waste to the injection zone. It is made of corrosion-resistant material and it is surrounded by the long string casing. This casing is sealed at the bottom by the packer and at the top by the well head. Operators must pressurize this space between the long string casing and the injection tubing to monitor for and to prevent leaks. Finally, the outermost wall, the well casing, supports the well structurally. Operators must maintain mechanical integrity of the well until plugged and abandoned.[30]

[29] 40 CFR Part 144.28(e)

[30] 40 CFR Part 144.28(f)

Figure 4: Diagram of Class I Well Technology[31]



Monitoring

Monitoring requirements include monitoring of the well and other formations. Class I well operators are required to analyze injection fluids to identify fluid characteristics, to use continuous recording devices to monitor injection pressure, flow rate, and volume, and to monitor for any leaks into drinking water with monitoring wells.[32] Operators also minimize any leaks by carefully watching injection pressure. If there is a leak in a well, the pressure in the well will drop as the fluids escape out of the circumference. Regulations require well operators to use continuous recording devices to monitor injection pressure, flow rate, and volume.[33] To demonstrate mechanical integrity, well operators must show that fluids will not

[31] Source: U.S. EPA website: http://www.epa.gov/safewater/uic/idealwel.html.

[32] 40 CFR Part 144.28(g)(1).

[33] 40 CFR Part 144.26(g)(1).

leak while traveling to the well, will not leak out of the well as it is injected, nor move into underground drinking water once injected into the deep rock.[34] The UIC program requires mechanical integrity demonstrations at least once every five years for both Class I and Class II wells.[35]

Class I operators are also required to develop approved ambient monitoring programs as determined by the Program Director to protect against fluid movement out of the injection zone. Monitoring programs are based upon a site-specific assessment and must include at a minimum annual monitoring for injection zone pressure.[36] The Director may also require the following as part of the monitoring program:

1) Continuous monitoring for pressure in the aquifer located directly above the injection zone;

2) Other site specific data to include information on the position of the waste front within the injection zone or water quality;

3) Monitoring of ground water quality of the aquifer located directly above the injection zone;

4) Monitoring of ground water quality in the lowest underground source of drinking water; and,

5) Any additional monitoring to determine if there is fluid movement into underground sources of drinking water.[37]

Class II well operators are required to monitor injected fluids to determine how it moves and changes while in the injection zone, and the frequency of which is determined in each permit based upon site specific criteria.[38] Operators are also required to monitor and record injection pressure, flow rate, and cumulative volume, the frequency of which can vary from daily to monthly, dependent upon the type of well operations.[39] Well operators must demonstrate mechanical integrity at least every five years.[40]

Reporting

Reporting requirements also differ between Class I and Class II wells. Operators of Class I wells must submit quarterly reports with the following information: various characteristics of the injection fluid, monthly average and minimum and maximum values for injection pressure, flow rate/volume, well pressure monitoring well results, and the results of injection

[34] 40 CFR Part 146.8

[35] 40 CFR Parts 146.13 and 146.23.

[36] 40 CFR Part 146.13(d)(1).

[37] 40 CFR Part 146.13(d)(2).

[38] 40 CFR Part 146.23(b)(1).

[39] 40 CFR Part 144.28(g)(2); 40 CFR Part 146.23(b)(2).

[40] 40 CFR Part 144.28(g)(2)(iv); 40 CFR Part 146.23(b)(3).

well tests.[41] Class II well operators are required to submit annual reports providing a summary of results from any required monitoring activities.[42]

Financial Assurance

For now, APPA is not aware of any additional financial assurance programs or systems envisioned for CCS. However, the existing law does require that financial responsibility is met. APPA has caution about embracing CCS technology and long-term storage or geosequestration for new power plants until this financial responsibility issue is better understood. To APPA's knowledge, there has been nothing like this level of financial assurance required in the electric power sector for conventional pollution issues and liability concerns.

Currently, Class I operators must demonstrate and maintain financial responsibility for each well to ensure the operator is financially able to eventually close and abandon the well in accordance with an approved well abandonment plan.[43] Class I operators have several options from which to choose in order to demonstrate financial responsibility.

1) Establish a trust fund in an amount equal to the estimated cost of plugging and abandonment;
2) Obtain a surety bond to guarantee payment into a standby trust fund;
3) Obtain a surety bond to guarantee well plugging and abandonment;
4) Obtain a letter of irrevocable plugging and abandonment letter of credit;
5) Plugging and abandonment insurance;
6) Meet financial criteria and obtain a corporate guarantee for plugging and abandonment; or,
7) Demonstrate financial responsibility using a combination of options 1, 2, 4, 5.[44]

Closure

Well operators must submit plans for plugging and abandonment as part of the permit approval process. [45] UIC program regulation requires Class I, II, III, and V wells to be plugged with cement sufficiently to prevent migration or leakage of the injection fluid. Class I permit holders must also monitor groundwater until they can demonstrate that the pressure in the injection zone decays to the point where there is no potential to influence underground drinking water sources.[46] Class V operators are also required to dispose of any waste, sludge, fluids, etc., that are found near the wells.[47] Well operators are required to submit a report

[41] 40 CFR Part 144.28(h)(1).

[42] 40 CFR Part 144.28(h)(2).

[43] 40 CFR Part 144.28(d).

[44] 40 CFR Part 144.63.

[45] 40 CFR Part 144.28(c).

[46] 40 CFR Part 14.28(g)(1)(iii).

[47] 40 CFR Part 146.10.

certified as accurate to the Director stating that well abandonment was conducted and completed in accordance with the abandonment plan.

What are the Challenges for Permitting CCS Under the UIC Program for Electric Utilities Evaluating CCS Options?

With the international, federal, and state interest in CCS, academic, public interest groups, and the federal government researchers are promoting the availability of sequestration sites. The Department of Energy estimates that North America has the capacity to store all of its annual power plant emissions underground. The APPA is very skeptical of DOE's optimistic view because APPA does not believe that hydrological concerns and proximity to transmission lines, water issues and other infrastructure needs have been considered. Yet, new electric utilities are being asked to respond and to consider CCS as part of new plant design now.

The APPA is concerned that these studies do not fully consider the technical, regulatory, and practical limitations of commercial-scale CCS. The current UIC regulatory program illustrates some of the major limitations utilities and policy officials must consider:

Cost and Space Requirements for CCS at the Power Plant

The DOE estimates that a 300 MW power plan will require 60 acres of land to build and to operate the carbon capture technology.[48] Constructing the pipeline terminus for $C0_2$ compression and transport via pipeline will require an additional 20 acres of land. DOE further estimates that carbon capture will consume 0.5 millions of gallons of water per day and over 15 megawatts of power or approximately 0.8 MGD per day for a 500 MW power plant. If utilities do not have readily available land and water, and can afford the costs of excess generating capacity, they will face limitations on their ability to construct CCS.[49]

Uncertainty Concerning Regulatory Requirements

Since EPA is formulating guidance or regulation on CCS and the UIC program, there is substantial uncertainty as to the ultimate siting, construction, and other permit requirements. If EPA embarks on a rulemaking, a final rule may not be promulgated until 2012. Once EPA completes its policies, states may enact their own more stringent provisions. This uncertainty complicates commercial scale planning for new power plants with coal on the drawing board today.

Operators of Class I, II, or III wells are expected to take corrective measures when there is noncompliance or malfunction of the injection system, which may include temporary shut down and capping of the well. The operators are required to notify the UIC regulatory manager within 24 hours of when the operator becomes aware of the problem. Operators are also expected to include in their noncompliance report its cause, period of time it occurred, actions taken (or are taking) to correct the issue, and plans to prevent recurrence.[50] Other specific requirements may be established as part of the operators UIC permit. However, the difficulty for well operators involved in CCS operations is finding an alternative means of disposing CO_2 emissions if injection operations must temporarily cease. Operators may have to negotiate this issue as part of the well permitting process.

[48] *NETL report*, at 2-44.

[49] *NETL report*, at 2-44.

[50] 40 CFR Part 144.28(b)

Limitations on Class I Well Siting

If EPA and states draw upon the criteria for Class I wells for CCS wells, there are regulatory, technical, and transportation limitations for CCS that utilities must consider. On a technical basis, some areas of the U.S. would be unsuitable due to the relatively increased risk of earthquakes, for example. Many of the coal regions of the United States also correspond to areas that are relatively geologically active (e.g., areas of Wyoming[51]). Injection near population centers along the West Coast also might be ruled out due to seismic concerns. Until the siting criteria are defined, utilities may not be certain whether they can inject locally or be required to pipe CO_2 hundreds of miles to areas with Class I wells such as the Gulf Coast.

Sheer Size of CCS to Have Meaningful Impact on U.S. GHG Emissions

Another limitation is that the EPA and states may not have the human and financial resources to administer an expansion of the UIC program for CCS. Comparing the relative size of CO_2 emissions and current underground injection gives some answer to this question. Power plants accounted for 2.4 billion metric tons of CO_2 emissions in 2006[52] or approximately 86 percent of point source CO_2 emissions in the U.S.[53]

By way of comparison, EPA reported that 21.8 million tons were injected into hazardous waste wells in 2005,[54] less than one percent of the amount of carbon dioxide released. Approximately 43 million metric tons of carbon dioxide is injected into wells today for enhanced oil and gas recovery.[55]

If perhaps 10-20 percent of carbon dioxide emissions were captured, the UIC programs would need to permit wells injecting masses 10 – 20 times the total mass currently injected for oil recovery or for all hazardous waste disposals. This expansion would pose a substantial challenge to the existing state permitting systems. APPA remains skeptical that more than a slip stream of CO_2 can be separated and injected and remains doubtful that a new coal power plant (regardless of type) could separate and inject more than 50 percent of the CO_2 from the plant.

[51] http://ga.water.usgs.gov/edu/gwdepletion.html

[52] Electric Power Research Institute, *Electricity Technologies in a Carbon-Constrained World*.

[53] *Carbon Sequestration Atlas*, at 11.

[54] U.S. EPA Office of Solid Waste and Emergency Response, *National Biennial RCRA Hazardous Waste Report: Based on 2005 Data*, Dec. 2006, at 2-5, Exhibit 2-5.

[55] Source: Advanced Resourced International, 2007.

Figure 5: Comparison of CCS Volumes to Current UIC Volumes

Injected Material	Mass of Material (mil. Metric tons/year)
CO_2 emissions from power plants	2,400[56]
CO_2 in Class II wells for oil recovery	43[57]
Class I hazardous waste	22[58]
Regional Carbon Sequestration Partnerships, total	2

Space Requirements for the Injection Well

DOE has estimated that injecting 0.9 million metric tons of CO_2 will require a land area of over 2,750 acres. This carbon mass is only 40 percent of one year's generation from a 300 MW coal power plant with a 90 percent efficient CCS. Using DOE's estimate, to hold 30 years of CO_2 captured from a 300 MW boiler, the surface area requirement is over 200,000 acres, or 312.5 square miles.[59] This land choice must also consider load, transmission lines, coal or rail access, surface water (used to produce electricity) and conventional air pollution issues such as SO_2 and NOX. The injection well, observational well and Area of Review (AoR) space issues will dictate where the future power plants can be built.

The U.S. DOE's estimate may significantly underestimate the land area needed. As a gas, carbon dioxide is different then diluted wastewaters currently injected in Class I wells. It is more buoyant than the underwater fluids and will rise to the top of the injection layer. If the injection layer has dips and rises, CO_2 will flow to fill in each rise first. In other words, unlike current injected fluids, it will migrate via diffusion on its own away from the injection well. Like natural gas, it will concentrate in traps miles away from the injection zone. In other words, applicants could have areas of review much greater than 2.5 miles currently thought protective for liquid injection. A study in the saline formations of Texas where there are many Class I wells suggests that a formation large enough to store 30 years of CO_2 from a single power plant could have traps over a 13 mile by 13 mile area.[60]

A further complication is the difference in property law traditions across the United States. In several Homestead laws, Congress gave away land to settlers who stayed upon and improved the land. However, the federal government retained the subsurface rights to the land, creating "split-estate" properties where the surface owner does not have title to the subsurface. Over 20 million acres of land in western U.S. states have split estates between private entities and the federal government.[61] In other states, the mineral rights have been sold to private parties creating split estates between parties. In the eastern U.S., property titles typically include surface and subsurface rights. Depending on the state, utilities may

[56] Electric Power Research Institute, *Electricity Technologies in a Carbon-Constrained World*.
[57] Source: Advanced Resourced International, 2007,
[58] U.S. EPA Office of Solid Waste and Emergency Response, *National Biennial RCRA Hazardous Waste Report: Based on 2005 Data*, Dec. 2006, at 2-5, Exhibit 2-5.
[59] *NETL report*, at 2-71
[60] J.P. Nicot *et al.*, *Area of Review: How large is large enough for carbon storage?*, Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin, 2006.
[61] NETL report, at 4-83.

face the limitation that it is impractical, impossible, or extremely costly to acquire title to hundreds of thousands of acres of land.

Unique Potential Hazards of Carbon Dioxide Injection

While deepwell injection of liquids has occurred safely for over 20 years, there is less experience with injecting gasses like CO_2. While most CO_2 injections for enhanced oil recovery have occurred safely, problems that have occurred illustrate the unique hazards that utilities and regulators must consider. A few of these potential hazards include the following.

Blowout

Well blowouts occur when gas escapes through old or unknown wells. In January 2001, a natural gas leak from a cracked gas well casing leading to salt caverns and used as a natural gas storage facility resulted in an initial gas explosion below two stores in downtown Hutchinson, KS. The initial gas explosion was followed by an eruption of natural gas and water geysers two miles east of the initial explosion later that day and for several days thereafter. Two people residing in a trailer home were killed as a result of one of the explosions. The gas leak originated from a cracked well casing at a depth close to 600 feet and proceeded to migrate horizontally, traveling along abandoned brine wells and ultimately reaching the surface some distance away from the initial explosion.[62]

In another case involving CO_2, a blowout occurred during drilling at a production well in March 1982 causing the free flow of CO_2 at the well head and leakage from ground fractures directly above the site. The high rate of CO_2 from the well caused containment not to occur until the following month.[63]

A report jointly funded by U.S. EPA and U.S. DOE looked at injection well accidents in both the U.S. and abroad and issued recommendations for protecting against future accidents.[64] The report issued a number of recommendations including: determining the potential for CO_2 migration along unsealed fault and fracture zones; the potential for magmatic or seismic activity to cause damage to sealing caps resulting in CO_2 releases; the potential for wells to transport CO_2 to the surface; and implementation of public education and CO_2 monitoring programs to minimize impact to human health and the environment from releases.[65]

The risk of blowout is hard to quantify since there is little information on the number of abandoned wells in the United States. It is difficult to estimate the number of these wells since some do not have observable caps or metal casings that can be detected through sensors. Texas estimates that there are approximately 11,000 orphan abandoned wells that it is gradually closing through a state program.[66] Operators of CCS injection wells will have to find, close, and cap abandoned wells within the Area of Review.

[62] Lewicki *et al.*, at 41-2.

[63] Lewicki *et al.*, at 39-40.

[64] Jennifer L. Lewicki *et al.*, *Natural and Industrial Analogues for Release of CO_2 from Storage Reservoirs: Identification of Features, Events, and Processes and Lessons Learned*, Earnest Orlando Lawrence Berkeley National Laboratory, Feb. 2006.

[65] Lewicki *et al.*, at 48-9.

[66] Source Texas Railroad Commission at: http://www.rrc.state.tx.us/news-releases/2006/100606.html..

The DOE has a method of finding abandoned wells under its SEQURE program, however this program is not set up for national application. The SEQURE program uses low flying airplanes to detect abandoned wells and, as discussed above, aerial methods may not detect wells which do not have metal cases or other markers.

Economic Damage

The saline formations in Texas produce some oil and gas in formations nearby or overlaying the potential injection formations. In addition to well blowout, less apparent seeps from the injection zone into oil and gas producing layers can dilute the value of these deposits and ultimately return the CO_2 to the atmosphere.[67]

Corrosion

As CO_2 rises to the top of the injection layer, it may contact closed wells or the cement casings of older wells. If the CO2 reacts with water to form acidic compounds, these acids could start to erode the concrete. As more is eroded, the process accelerates, creating a reinforcing-negative cycle that could allow the CO_2 to rise up the abandoned well to drinking water layers. While this problem can be prevented through different well closure approaches, the potential problem will increase the cost of an applicant's Area of Review study and demonstration.[68]

Permitting Costs

In 2001, EPA estimated the costs of the siting requirements – the geologic study, the Area of Review study, and the no migration petition – as at least \$2 million for a Class I hazardous waste well.[69] EPA based its estimate on applicant experience, including an Area of Review of 2.5 miles. If, as discussed above, the zone of influence could stretch to a radius of 13 miles, the Area of Review would be 26 times larger than for a typical Class I well. The siting studies and corrective measures for closing abandoned wells could approach \$20 to \$50 million. Operators (presumably electric utilities) would still need to pay for the well construction costs (estimated to be well over \$1 million), permitting fees, operating, and the other costs.

Regulatory Capacity

In all, a Class I permit application can fill a bookcase with the required plans, analyses, and reports. States may spend over a year reviewing a renewal permit and several years reviewing a new Class I well permit.[70] Because of the regulatory burdens, APPA staff speculates that states will require considerable permit fees to pay for these new state employees as well as analyses of new and renewed[71] permit applications. Class II permits can be approved more rapidly. However, and as the maps show, as the UIC program has matured, Class I and II wells primarily now only occur where there is ample experience and knowledge of local and regional geography.

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[67] Nicot, et al.

[68] Nicot, et al.

[69] EPA, 2001, at 20.

[70] Source: Texas Commission on Environmental Quality (TCEQ) at http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/sfr/057_06.pdf.

[71] Class I permits may remain in effect for up to ten years as determined by the Program Director. See, 40 CFR 144.28.

Even moderate adoption of CCS by new electric utilities would be the biggest expansion of underground injection in U.S. history. From the volumes above, the U.S. must undertake a dramatic expansion in its technical infrastructure to support safe CCS. In the private sector, engineers and geologists must identify, map, and investigate many more UI sites. In the near term there may be a shortage of experienced investigators. For the public sector, the skill gap is even more critical. Regulatory agencies must have sufficient in-house experience to review all of the technical information provided and to evaluate permit applications against the regulatory standards.

The size of the current regulatory skill shortage is illustrated by the following:

- ***Less than half of regulatory agencies across the states have experience reviewing Class I or Class II permits***. As the charts show, only about 20 states have experience permitting deep, high-volume injection wells. For CCS to occur in geologic formations around the U.S., many states must hire and train permitting staff or rely on EPA regional offices.

- ***Experience is concentrated in a few regions of the country***. Current experience is not distributed throughout the country, but concentrated in Texas, Louisiana, Florida, and a few other states. Unless states accept deep well injection in their states, CCS may require special CCS pipelines or via surface shipping carbon dioxide gas hundreds or thousands of miles from a power plant to an injection well. Pipeline shipment and booster compressors along the CCS pipeline increase the cost and perhaps the perception of the hazards of CCS.

- ***EPA regions must also boost their technical capacity***. It is not only states that will be deluged with CCS permit applications. EPA regions approve UIC permits in some of the nation's largest states and in states with large coal-fired power plants. EPA regions must craft their own approaches and technical requirements for CCS Class V permit applications.

- ***Even in states with experience, states would need a significant boost in resources to permit a larger number of CCS wells***. In 2006, Texas had ten new and eight Class I hazardous waste permit renewals under review. The average processing time was over one year for these permits. If CCS increases by a factor of ten the effective number of Class I wells in Texas, the regulatory system must either grow rapidly or the time needed to gain approval will soar.

Another consideration is the increased regulatory burden faced by electrical utilities when partnering with enhanced oil recovery (EOR) operations. Electrical utilities partnering with Class II well operators for EOR presumably would be subject to current Class I regulatory provisions, and ultimately any new regulatory requirements or framework established by U.S. EPA specifically to address CCS injection activities.

Conclusion

Although the concept of CCS sounds promising, regulatory agencies' paramount responsibility will be to ensure current and future protection of the nation's drinking water supplies. For CCS to have a meaningful impact on U.S. power plant emissions, the mass of CO_2 to be injected underground will dwarf current amounts by 10 to 20 times. While the nation has the ingenuity to tackle this challenge, it will require investing in technical skills, data, research, and education both in the private sector and in regulatory agencies. At the same time, there are major limitations that appear to preclude commercial-scale CCS in many parts of the country. APPA commissioned this paper to demonstrate the necessary regulatory systems needed to properly permit CCS into non-oil and gas or EOR sites.

This paper does not outline the necessity to deal with other issues such as amending state drinking water laws or amending federal environmental laws such as the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); Endangered Species Act (ESA), Resource Conservation and Recovery Act (RCRA), and CERCLA's Natural Resource Damage Assessment Act (NRDA). These issues have been addressed by other APPA papers located at www.appanet.org/files/HTM/ccs.html

Recommendations

APPA recognizes that controlling CO_2 emissions can bring about reductions in greenhouse gases . While there is considerable support for CCS and its promise for achieving sizeable emissions reductions, it is not clear the current regulatory structure and framework adequately addresses the limitations and adverse impacts related to CCS that have been noted above. APPA wants to ensure that these issues receive consideration and are appropriately addressed prior to moving forward with commercial-scale use of CCS.

1. APPA recommends that establishment of a process to ensure states and Public Utility Commissions are made aware of the limitations of CCS as addressed in this paper and that the issues be fully investigated prior to mandating CCS as part of permit approval.

2. APPA looks forward to working with the U.S. EPA on the cross-cutting or multimedia regulatory issues such as water use, drinking water, and air issues as they move forward with determining the best regulatory framework through which to review, approve, monitor commercial-scale carbon capture and storage projects.

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