UIC PROGRAM MECHANICAL INTEGRITY TESTING: LESSONS FOR CARBON CAPTURE AND STORAGE?

Jonathan Koplos[1], Bruce Kobelski[2], Anhar Karimjee[3], and Chi Ho Sham[4]

1 Senior Associate, The Cadmus Group, 57 Water Street, Watertown, MA 02472; Voice: 617-673-7184; Fax: 617-673-7001; Email: jkoplos@cadmusgroup.com

2 Team Leader, Office of Ground Water and Drinking Water, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW, Washington, DC 20460; Voice: 202-564-3888; Fax: 202-564-3756; Email: kobelski.bruce@epa.gov

3 Team Leader, Climate Change Division, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW, Washington, DC 20460; Voice: 202-343-9260; Fax: 202-343-2202; Email: karimjee.anhar@epa.gov

4 Vice President, The Cadmus Group, 57 Water Street, Watertown, MA 02472; Voice: 617-673-7156; Fax: 617-673-7001; Email: csham@cadmusgroup.com

Executive Summary

Implementation of mechanical integrity testing (MIT) requirements is a cornerstone of the Underground Injection Control (UIC) program. Title 40 of the Code of Federal Regulations Section 146.8 defines mechanical integrity (MI) for injection wells—an injection well has MI if there is no significant leak in the casing, tubing, or packer (internal MI) and no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the wellbore (external MI). UIC Class I and Class II injection wells must pass MI requirements prior to operation and must continue to demonstrate MI with testing throughout operation.

Given the corrosive nature of (wet) carbon dioxide, MI is an important issue for designing risk management strategies for carbon dioxide (CO_2) injection wells. Corrosion can affect well tubing, packer, casing, and cement in injection wells (and in abandoned wells that penetrate the injection/storage zone). As stated in a paper presented at the recent International Association of Drilling Contractors/Society of Petroleum Engineers Drilling Conference, "[a] leaking wellbore annulus can be a pathway for CO_2 migration into unplanned zones (other formations, adjacent reservoir zones, and other areas) leading to economic loss, reduction of CO_2 storage efficiency, and potential compromise of the field for storage" (Barlet-Gouedard et al., 2006). MIT requirements are an important issue for permitting CO_2 injection wells because MI failure could jeopardize the viability of a CO_2 sequestration project or harm human health or the environment.

An assessment of available MIT information indicates that accessible information is very limited and is not comprehensive, detailed, or national in scope. Several studies of MIT results have previously been conducted by the U.S. Environmental Protection Agency (EPA) and information regarding MIT failure rates, types, and consequences from those studies are summarized here. The most common MIT problems reportedly are leaky packers for Class I injection wells and casing for Class II injection wells. Wells that inject hazardous (more corrosive) fluids have MIT failure rates 2 to 3 times higher than wells injecting non-hazardous fluids. The limited data do suggest, though, that improvements have been made in the environmental performance of injection wells since the inception of the UIC program. Given the lack of detailed, national data on injection well performance and mechanical integrity, the sharing of well performance data between industry and government may provide the most directly relevant and useful information necessary for a well-informed and transparent development of CO_2 injection regulations for full-scale commercial CO_2 sequestration operations.

1. Introduction

Regulations for a federal Underground Injection Control (UIC) program were promulgated in 1980 to ensure that injection practices do not endanger underground sources of drinking water (USDWs).[1] The cornerstone of the UIC program is mechanical integrity testing of deep injection wells. Routine testing of injection well mechanical integrity serves to identify problems that could lead to movement of injected fluids into USDWs. By monitoring mechanical integrity (MI) and identifying mechanical integrity test (MIT) failures, this important component of the UIC program provides the information needed for timely response to and remediation of well integrity problems before serious threats to

[1] A USDW is an aquifer or portion of an aquifer that supplies a public water system (PWS) or contains enough water to supply a PWS, supplies drinking water for human consumption or contains water with less than 10,000 milligrams/liter of total dissolved solids, and is not exempted by EPA or state authorities from protection as a source of drinking water.

USDWs actually develop. Stated differently, demonstrating injection well mechanical integrity is the most common way to establish that there is no movement of fluids into USDWs due to injection practices.

The issue of mechanical integrity is expected to be a key consideration as CO_2 capture and storage programs are developed in the U.S. Many studies identify compromised well bore integrity as a key potential source of CO_2 leakage. The 2005 report of the CO_2 Capture and Storage Project for Carbon Dioxide Storage in Deep Geologic Formations for Climate Change Mitigation states that "well integrity issues are clearly becoming more of a concern than geologic integrity issues" regarding geosequestration of CO_2. The Well Bore Integrity Workshop of the International Energy Agency (IEA) Greenhouse Gas R&D Programme (2005) notes that "[t]he integrity of well bores, their long-term ability to retain CO_2, has been identified as a significant potential risk for long-term security of geological storage facilities." The Intergovernmental Panel on Climate Change 'Special Report on Carbon Dioxide Capture and Storage' (2005), states that "[p]etroleum industry experience with CO_2 injection for EOR (Enhanced Oil Recovery) suggests that leakage from the injection well, resulting from improper completion or deterioration of the casing, packers, or cement, is one of the most significant potential failure modes for injection projects." And as stated in a paper presented at the recent International Association of Drilling Contractors/Society of Petroleum Engineers Drilling Conference, "[a] leaking wellbore annulus can be a pathway for CO_2 migration into unplanned zones (other formations, adjacent reservoir zones, and other areas) leading to economic loss, reduction of CO_2 storage efficiency, and potential compromise of the field for storage" (Barlet-Gouedard et al., 2006). Some of these concerns relate to long-term CO_2 exposure to abandoned wells that penetrate a CO_2 injection and storage zone. The fundamental concern, though, relates to well (and wellbore) integrity and the corrosive nature of wet CO_2 that can affect well tubing, packers, casing, and cement (Scherer *et al.*, 2005; Seiersten and Kongshaug, 2005; Christopher *et al.*, 2005; Shen and Pye, 1989; Bruckdorfer, 1986). Corrosion can degrade and compromise the integrity of wells. A loss of well integrity can potentially result in a leak of injectate, which could, depending on volumes released, render a CO_2 sequestration project ineffective and/or potentially endanger a USDW.

Prior to EPA's regulation of Class I injection wells, several highly visible and documented cases of well failures occurred, one releasing wastewater into a USDW and the other releasing wastewater into Lake Erie. Since the inception of the UIC program nearly 26 years ago, the environmental performance of injection wells has improved. The overall rate of failed MITs of injection wells has decreased, and there have been no significant contamination incidents since the passage of UIC regulations. To address the future concerns of CO_2 corrosion of well materials and well integrity, a detailed review of the availability and usefulness of MIT information is conducted here and assessed in the context of general CO_2 injection well issues.

This report begins with an overview of the UIC program, focusing on Class I and Class II injection well requirements and injection well MITs. These two UIC well classes consist of relatively deep injection wells and therefore provide the most direct operational analogues for the types of wells anticipated for use in CO_2 injection for geologic storage. Summaries are then presented of existing UIC Class I and Class II injection well MIT studies from the 1990s, and of MIT information available to EPA through the UIC program's "7520 forms," the primary means by which MIT information is provided from the States to EPA. The summary reviews of these studies and the 7520 forms highlight that EPA has very limited MIT performance data that is readily accessible and national in scope. Information is also briefly summarized from experimental and in-field experience with CO_2 corrosion. The reports ends with a summary and general conclusions, and also identified information gaps and suggested steps for further research that hopefully can serve to better define specific well integrity issues for CO_2 injection and geosequestration.

2. Overview of Class I and II Well Inventories and Regulations

In 1980, EPA published final technical regulations for the UIC program. The regulations define, among other details, five classes of injection wells, based on their construction, use, and the types of fluids injected. Two injection well classes– Class I and Class II- are potential analogues for CO_2 injection.

Class I wells, by definition, inject fluids, including industrial or municipal wastewater, beneath the lowermost underground source of drinking water (USDW) and below a confining zone. Class I injection zones typically range in depth from 1,700 to over 10,000 feet below the surface. Class I wells are classified as hazardous or non-hazardous, depending on the characteristics of the wastewaters injected. Typically injected in these wells is wastewater associated with the chemical products, petroleum refining, and metal products industries including manufacturing process wastewater, mining wastes, municipal effluent, and blowdown from cooling towers and air scrubbers. In Florida, Class I municipal wastewater disposal wells are used to inject secondary treated domestic wastewater below the lowermost USDWs. The hazardous nature of some of these injected fluids requires that the wells be constructed of corrosion-resistant materials; this sophisticated construction is a potential analogue for CO_2 injection.

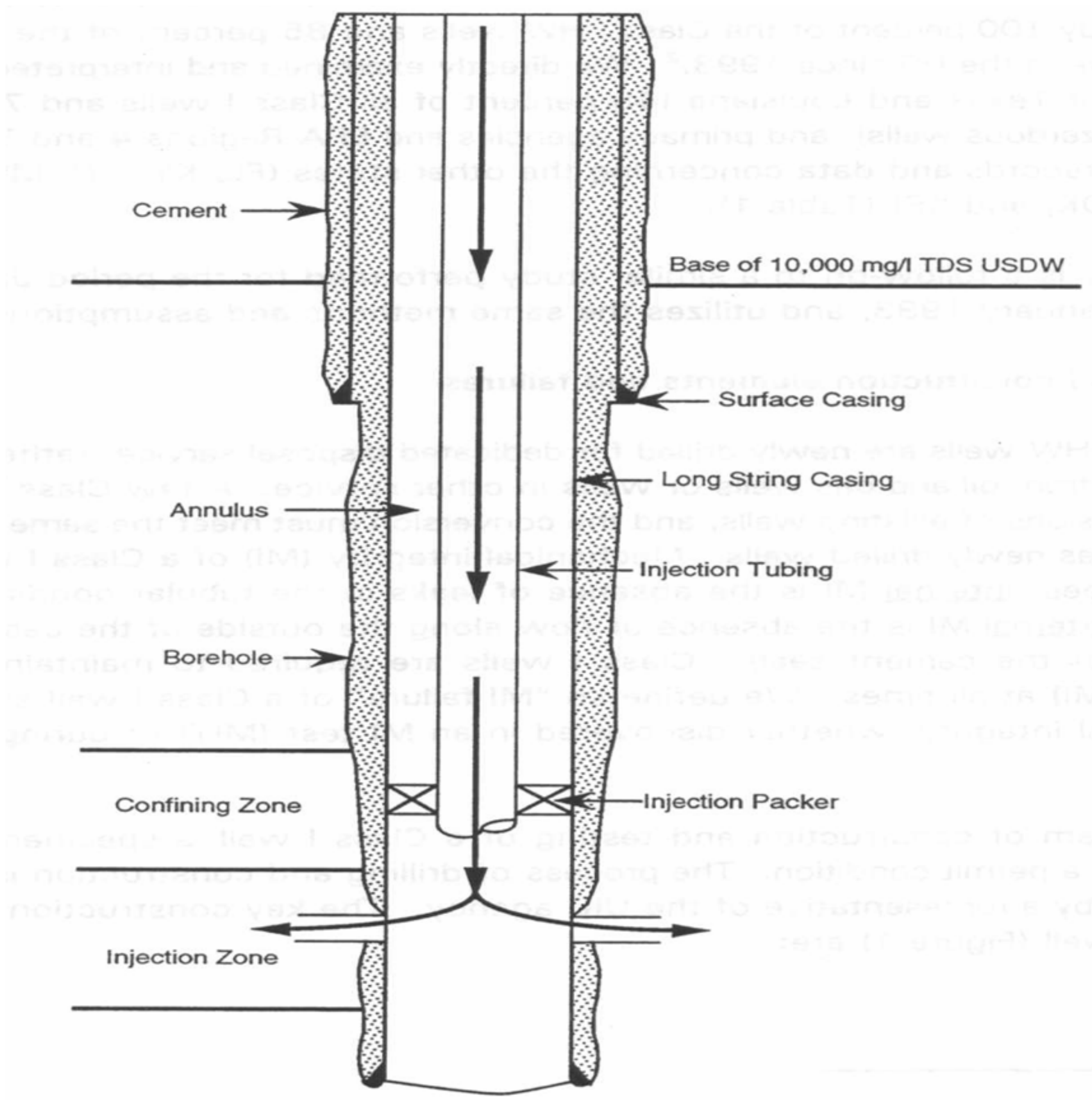
According to EPA's current reported well inventory there are an estimated 549 Class I injection wells in the US consisting of 119 hazardous waste wells and 430 non-hazardous waste wells with most wells located in EPA Regions 6 and 5 (based on the UIC Well Inventory Reporting System as of February 27, 2006). All Class I hazardous waste injection wells are found in 10 States with most located in Texas (58), Louisiana (18), and Ohio (10). Class I non-hazardous injection wells are located in 19 States, with most located in Florida (163; primarily municipal wells), Wyoming (50), Texas (45), Kansas (43), and Louisiana (25) (UIC Well Inventory, February 27, 2006).

Class II wells are used to dispose of fluids which are brought to the surface in connection with oil or natural gas production, to inject fluids for enhanced recovery (EOR) of oil or natural gas, or to store liquid hydrocarbons. Some EOR operations inject CO_2 to displace oil and gas deposits; therefore, these are good analogues for CO_2 sequestration. There are an estimated 147,753 Class II wells in the US in 33 States, with most wells located in the following States: Texas (49,975), California (26,305), Kansas (16,526), Oklahoma (11,365), Illinois (7,944), Wyoming (4,723), New Mexico (4,699), Louisiana (3,509), Kentucky (3,189), and Ohio (2,801) (UIC Well Inventory, February 27, 2006).

Injection wells in the U.S. are either overseen by States that have been granted primary enforcement authority (primacy) to manage the program in the State or are directly implemented by EPA's regional offices. The MIT requirements for Class I and Class II wells differ. The remainder of this section focuses on MIT requirements for Class I and Class II wells.

Mechanical integrity (MI) is defined as the absence of significant leaks in the casing, tubing, or packer (known as internal MI or Part I MI or MI1), and the absence of significant fluid movement into a USDW through vertical channels adjacent to the well bore (external MI or Part 2 MI or MI2). Exhibit 1 presents a schematic diagram of a typical injection well.

Exhibit 1: Schematic diagram of a typical injection well



A number of EPA approved tests can be used to demonstrate internal MI, pursuant to 40 CFR §146.8(a)(1), including:

- annulus pressure or annulus monitoring test;
- radioactive tracer test;
- water-brine interface test;
- pressure test with liquid or gas; or
- monitoring records showing the absence of significant changes in the relationship between pressure and injection flow rate (certain Class II enhanced recovery wells only).

External MI can be demonstrated, pursuant to 40 CFR §146.8(a)(2), using the following tests:

- temperature log;
- noise log;
- oxygen-activation log indicating lack of fluid migration behind the casing;
- radioactive tracer survey indicating lack of fluid migration behind the casing;
- cement bond log showing gamma ray, transit time, collar locator and variable density log; or
- cementing records (in lieu of any tests or logs) that demonstrate the presence of adequate cement to prevent migration of fluids into a USDW (Class II wells only).

A summary of requirements for UIC Class I hazardous, Class I non-hazardous, and Class II injection wells, including requirements related to mechanical integrity testing, is presented in Exhibit 2. Well permit standards and conditions are set to be appropriate for each well class and include construction requirements. For example, for both Class I and Class II wells, all permits will require demonstration that casing and cementing are adequate to prevent movement of fluid into or between USDWs. Cement bond logs are often needed to evaluate the adequacy of the cementing records, especially for Class II wells (USEPA, 2002). In the case of oil production wells converted to injection wells, the converted well simply must meet all injection well requirements.

<table>
<tr><th colspan="7">Exhibit 2: Summary of UIC Class I and Class II Injection Well Requirements (40 CFR 146 and 148)</th></tr>
<tr><th rowspan="3">Well Class</th><th rowspan="3">Permit Required</th><th rowspan="3">Area of Review [1] (AoR)</th><th colspan="4">Injection Wells [2]</th></tr>
<tr><th colspan="2">Mechanical Integrity Tests</th><th rowspan="2">Other Tests</th><th rowspan="2">Monitoring and Reporting Frequency</th></tr>
<tr><th>Part I MI (Internal)</th><th>Part II MI (External)</th></tr>
<tr><td>Class I – Hazardous</td><td>Yes

Plus Land Ban Petition (see 40 CFR 148)</td><td>2-mile (minimum) fixed radius

Provide construction information for all wells that penetrate the injection zone.</td><td>Pressure test annually and after each workover</td><td>Temperature, noise, or other approved log at least every 5 years</td><td>Annual radioactive tracer survey, annual pressure fall-off test, casing inspection log after each workover, continuous corrosion testing</td><td>Continuous injection pressure, flow rate, volume, temperature, and annulus pressure + fluid chemistry + ground water monitoring as needed.

Quarterly reporting.</td></tr>
<tr><td>Class I – Non-Hazardous</td><td>Yes</td><td>1/4-mile (minimum) fixed radius

Provide construction information for all wells that penetrate the injection zone.</td><td>Pressure test or alternative test at least once every 5 years</td><td>Temperature, noise or other approved log at least every 5 years</td><td>Annual pressure fall-off</td><td>Continuous injection pressure, flow rate, volume, and annulus pressure + fluid chemistry and yearly pressure fall-off test.

Quarterly reporting.</td></tr>
<tr><td>Class II</td><td>Yes

Except for Enhanced Oil Recovery (EOR) wells authorized by rule</td><td>1/4-mile (minimum) fixed radius or radius of Zone of Endangerment [3]

Provide construction information for all wells that penetrate the injection zone.</td><td>Pressure test initially and every 5 years for brine disposal wells</td><td>Adequate cement records may be used in lieu of logs</td><td>Annual fluid chemistry and other tests as needed/ required by permit</td><td>Injection pressure, flow rate and cumulative volume, observed weekly for disposal and monthly for enhanced recovery.

Annual reporting.</td></tr>
</table>

Source: Modified from USEPA, 2002

[1] This information is used to determine if any abandoned or existing wells within the area of review require corrective action (such as plugging) prior to the start of injection well operations.
[2] These requirements pertain only to the injection wells and are generally used to demonstrate mechanical integrity; additional details are provided in the text.
[3] The Zone of Endangerment (ZoE) is the region where injection pressures may force fluid out of the intended injection reservoir and into a USDW

Because of the stringent requirements established for Class I hazardous and non-hazardous wells in 40 CFR 146 and 148, oversight on Class I injection wells has been more centralized and rigorous across the primacy States and EPA direct implementation (DI) programs

In comparison, the flexibility in the Class II program results in a range of specified details and of stringency across the different States regarding their MIT requirements. Readily available information accessed during this study suggests that of the seven States with the most Class II wells, only three (Illinois, Kansas, and Ohio) explicitly required both internal and external MIT for all Class II wells. California and Oklahoma only explicitly required external MIT (fluid migration tests) for wells without a casing-tubing annulus. Texas and New Mexico regulations had no mention of external MIT/fluid migration tests, and a pressure test was all that was required to demonstrate internal MI. Of the seven States with the most Class II wells, Texas and Oklahoma provided the most comprehensive and thorough regulations including detailed step-by-step instructions for conducting pressure tests. Other States simply identified that pressure tests were required.

3. Summary of Studies of Well Mechanical Integrity Testing

a. Research Methods

This report is based on information obtained through a systematic search for and review of pertinent documents, technical reports, guidance and regulatory materials, websites, bibliographies, conference presentations/proceedings, industry journal articles, and reference books. Many unpublished State and federal documents, reports, and studies were also obtained and reviewed. Searches were conducted using the EPA website, State government websites, the Society of Petroleum Engineers (SPE) website, and the American Petroleum Institute (API) website, among others. Search terms used included (but were not limited to): "mechanical integrity," "mechanical integrity test," "MIT," "Class I wells," "Class II wells," "enhanced oil recovery wells," "carbon dioxide corrosion," and "underground injection control." Most of the documents obtained and reviewed were State or federal reports, industry/ government conference proceedings, or large compilations published by organizations such as the Intergovernmental Panel on Climate Change (IPCC) or the International Energy Agency (IEA) Greenhouse Gas Research and Development (R&D) Programme. A number of older documents are only available in hardcopy.

b. Class I Injection Well Mechanical Integrity Issues

Prior to EPA's regulation of Class I injection wells, several cases of well failures occurred, at least one of which leaked wastewater into a USDW. The Hammermill Paper Company in Erie, Pennsylvania, and the Velsicol Chemical Corporation in Beaumont, Texas, are two examples of well failures.

In April 1968, corrosion caused the casing of Hammermill Paper Company's No. 1 well to rupture, releasing spent pulping liquor to the land surface which eventually flowed into Lake Erie. Additionally, a noxious black liquid seeped from an abandoned gas well at Presque Isle State Park, five miles away. The Pennsylvania Department of Environmental Resources suspected (though never conclusively determined) that wastewaters from Hammermill's injection well migrated up the unplugged, abandoned well bore.

In 1974 and 1975, the Velsicol Chemical Company noted lower than normal injection pressures in one of its two injection wells, which was designed without tubing. In 1975, Velsicol shut down the well to determine the cause of the decreased injection pressures, and an inspection revealed numerous leaks in the well's casing. The company decided to plug the well and drill a new one. During the course of the abandonment, Velsicol determined that contaminated wastewater had leaked to a USDW. The wastewater was pumped from the aquifer.

Since passage of the UIC regulations, several studies have assessed the performance of injection wells, particularly MIT failure rates. These studies, which were reviewed and summarized in this report, are listed and briefly described below:

-- *A Class I Injection Well Survey (Phase II Report): Survey of Operations.*
Prepared by the Underground Injection Practices Council (UIPC), December 1987. Referred to as “UIPC (1987).” This was a nationwide study of more than 400 Class I injection wells.

-- *Hazardous Waste–-Controls Over Injection Well Disposal Operations.*
Prepared by the U.S. General Accounting Office (GAO) 1987. Referred to as “GAO (1987).”

-- *Class I Well Failure Analysis: 1988-1991.*
Prepared by The Cadmus Group, Inc., for USEPA Office of Ground Water and Drinking Water (OGWDW), Underground Injection Control Branch (UICB), March 1993. Referred to as “USEPA (1993).” This report is based on information from 100% of Class I hazardous wells and 75% of all non-hazardous wells in operation during the period of the analysis. (Note that the summary statistics presented below for MIT performance between 1988 and 1992 from this USEPA study include all information from Texas Class I injection wells as hazardous waste wells. This relates to all summary information of the rates, types, and consequences of Class I injection well MIT failures. Prior to 1993, Texas did not distinguish between Class I hazardous wells and non-hazardous wells, all Class I injection wells were authorized to inject hazardous waste, and all Class I injection wells were subject to more stringent requirements.)

-- *Class I Mechanical Integrity Failure Analysis: 1993-1998*.
Prepared by ICF, Inc., for USEPA, OGWDW, UICB. September 1999. Referred to as “USEPA (1999).” This report is based on information from 100% of Class I hazardous wells and 85% of all non-hazardous wells active in the US since 1993. This report was used as the basis to develop and present ranges of MI failure summary statistics. (The range reflects the somewhat subjective interpretation of MI test results.) The upper end of the range is represented by estimates presented in USEPA (1999), and the low end estimates represent different interpretations of the USEPA (1999) findings for Texas (as developed through communications between EPA Region 6, the Texas Natural Resource Conservation Commission, and USEPA).

-- *Analysis of the Rate of and Reasons for Injection Well Mechanical Integrity Test Failure*.
Browning, L.A. (The Cadmus Group, Inc.) and J.B. Smith (USEPA). Presented at SPE/EPA Conference, March, 7-10, San Antonio, TX. Referred to as “Browning and Smith (1993).” The report describes the rates of and reasons for failure of over 10,000 scheduled MITs in Class II wells, for a variety of completion types, in the States of Louisiana, Michigan, Nebraska, and Pennsylvania, over two 5-year MIT cycles. The report states that of the 28 State UIC programs, only 8 States use well-history databases that provided more extensive information on MIT failures, reasons for failures, etc. From these eight States (NY, PA, AL, KY, IN, MI, LA, and NE), the four States mentioned above were selected to provide the best distribution across a range of important geologic and well construction/well age variables. It cannot be determined how nationally representative the MIT results from these four States are. Also, during the time period of this study, many wells that had been authorized by rule (“grandfathered in”) were being phased out of operation, so the mechanical integrity test results presented aggregate across a period of significant change.

A summary of the findings from these studies are provided below.

MIT Failure Rates

- UIPC (1987) cited well MI failure rates of approximately 9% of 500 Class I wells.

- GAO (1987) identified 11 cases or suspected cases of well MI failure.

- USEPA (1993), for the period 1988 to 1992, reported 135 cases of internal MI failure in a total of 428 Class I wells (a 32% ratio of MI failures to active wells; note, this is not the fraction of wells with MI failures because a single well can have multiple MI failures). All these cases of MI failure were detected during operation by continuous annulus monitoring. Only one external MI failure was reported. Class I hazardous waste wells had proportionately many more internal MI failures (107 MI failures in 240 wells) than did non-hazardous waste wells (28 MI failures in 188 wells), presumably due to the more corrosive nature of hazardous waste injectate.

- Based on the USEPA (1999) report, for the period 1993 to 1998, a range of values for MI failures is presented. The upper end of the range is represented by estimates presented in USEPA (1999), and the low end estimates represent different interpretations of the USEPA (1999) findings for Texas.

  The high end estimate (USEPA, 1999) indicates 122 cases of internal MI failure among 432 wells (a 28% ratio of MI failures to active wells; note this is not the fraction of wells with MI failures because a single well can have multiple MI failures). The low end estimate is 99 cases of internal MI failure among 435 wells (a 23% ratio of MI failures to active wells).

  As presented in USEPA (1999), Class I hazardous waste wells had proportionately many more internal MI failures (62 MI failures in 130 wells) than did non-hazardous waste wells (60 MI failures in 302 wells). The upper and lower range hazardous to non-hazardous well comparison information is not available. Six external MI failures were reported with all occurring in Texas (these were detected by routine external MI testing and all were in hazardous waste injection wells).

Types of MIT Failures

- UIPC (1987) cited leaky packer assemblies as the most common failure.

- GAO (1987) pointed to corrosion of casing or tubing as causes of failures.

- USEPA (1993) reported overall (hazardous plus non-hazardous) well internal MI failures comprising 37% tubing failures, 21% packer failures, and 17% long string casing failures. Injection wells handling hazardous (more corrosive) waste had higher rates of packer and casing failures, and lower rates of tubing failures compared to wells handling non-hazardous waste. Tubing failures, though, are the most common type of MI failure for both well types. Specific rates of types of failures are: Class I hazardous wells - 35% tubing, 23% packers, and 18% casing failures, and; Class I non-hazardous wells - 46% tubing, 14% packer, 14% casing.

- Based on the USEPA (1999) report, for the period 1993 to 1998, ranges of types of failures are presented (with details regarding the ranges described above). The high end estimate reported overall internal MI failures comprising 37% tubing failures, 20% packer failures, and 34% casing failures. The low end estimates for types of failures are 42% tubing failures, 25% packer failures, and 23% casing failures.

  USEPA (1999) found that injection wells handling hazardous waste had slightly higher rates of tubing and casing failures, and lower rates of packer failures compared to wells handling non-hazardous waste. As in the 1988-1992 time period, tubing failures are the single most common type of MI failure for both well types. The high end estimates rates of types of failures are: Class I hazardous wells - 39% tubing, 13% packers, and 36% casing failures, and; Class I non-hazardous wells - 35% tubing, 27% packer, and 33% casing failures. (Information for hazardous and non-hazardous distinction was not available for the low end estimates.)

Consequences of MIT Failures

- UIPC (1987) reported that 2% of the failures (6 wells) resulted in leaks into USDWs.

- GAO (1987) cited that two wells contaminated a drinking water aquifer (the Hammermill and Velsicol cases).

- USEPA (1993) stated that none of the 135 cases of internal MI failure (since the federal program was established) affected a USDW. The single reported external MI failure did not result in waste migration out of the injection zone or into a USDW. (There were five cases of migration out of the injection zone, but most, and possibly all, were due to migration through natural fractures away from the wellbore and were not related to well integrity problems.)

- USEPA (1999) reported that none of the internal MI failures affected a USDW. (There were 26 cases of reported migration out of the injection intervals, including three known and seven suspected cases in Florida affecting USDWs and 16 cases involving migration into permitted or unpermitted saline zones. All the Florida cases are associated with municipal wastewater injection and may be the result of migration through natural fractures away from the wellbore. Buoyancy differences between the injectate (wastewater) and more dense formation water caused fluid movement at much greater rates than predicted.

c. Class II Injection Well Mechanical Integrity Issues

Information on Class II MIT issues is more much limited than that for Class I wells. The findings above were based on MI/MIT assessments for 100% of Class I hazardous wells and 75-85% of Class I non-hazardous wells. The findings below are based on nearly 10,000 scheduled MITs from four States; there are approximately 148,000 Class II wells in 33 States.

MIT Failure Rates

- For the period from1983 to 1991, Browning and Smith (1993) reviewed records from 9,553 scheduled MITs in four States (Pennsylvania, Michigan, Louisiana, and Nebraska).[2] The overall MIT failure rate was 10.5% (ranging from 3% to 12% in the different States). Because many operators "pre-test" their wells and repair any defects prior to the official scheduled MIT, the authors report that the actual number of potential MIT failures could conceivably be 50% higher than reported in their study. The study did not specify between internal or external MITs. In most States, various pressure tests, water-in-annulus, or other tests may be performed for internal MI, but external MI is typically evaluated with a single submission of cementing records as evidence of a proper cementing.

[2] The actual number of wells involved in these MITs is not presented in the report.

Types of MIT Failures

- Browning and Smith (1993) report very incomplete records regarding types of MIT failures. Only 46% of the records they reviewed identified the reason for MIT failure. Of these, 54% identified casing failure, 25% tubing failure, and 19% packer failure. Casing failures were the highest cause of MIT failures in Pennsylvania (81%), where all the nearly 1,800 MITs reviewed were of Class II enhanced oil recovery wells (in contrast to Class II disposal wells).[3]

Consequences of MIT Failures

- Browning and Smith (1993) report that, of the wells with casing failures, about one-fifth were completed without tubing and packers, so the casing failure potentially allowed waste to migrate outside the wellbore. Browning and Smith also conclude that many of the actual failures were perhaps serious, or at least not worth re-working and repair, because about a quarter of the wells with casing failures were plugged within 60 days of the failing MIT.

4. Relevant Data from 7520 Reporting

a. Forms with Information Potentially Relevant to Geological Sequestration of CO_2

Nationally, the 7520 forms are the vehicles by which information on MIT results are reported. See Exhibit 3 for the specific information reported on each form. Form 7520-3: Inspections – Mechanical Integrity Testing contains the most detailed national-level information on MI of injection wells.

In Part V, Summary of Inspections, the form requests the total number of wells inspected, and the number of various types of inspections performed, including mechanical integrity tests (MITs) witnessed, emergency response or complaint response inspections, well constructions witnessed, well pluggings witnessed, and routine/periodic inspections.

In Part VI, summary of mechanical integrity (MI), the form collects the number of wells that passed and failed MITs as follows:

- Internal MITs for significant leaks (e.g., annulus pressure monitoring record evaluations, casing/ tubing pressure tests, monitoring record evaluations, and other significant leak tests/evaluations).
- External MITs for fluid migration (e.g., cement record evaluations, temperature/noise logs, radioactive tracer/cement bond tests, and other fluid migration tests/evaluations).

Part VII summarizes remedial actions taken as a result of MITs, including the total number of wells with remedial action, and the number of remedial actions taken (e.g., casing repaired/ squeeze cement remedial actions, tubing/packer remedial actions, plugging/ abandonment remedial actions, and other remedial actions). Other 7520 forms that may include potentially relevant information are described below:

[3] USEPA Region 3 staff stated that during this time period, many Class II wells that pre-dated the UIC program (i.e., wells that were "grandfathered" into the program) were in the process of being removed from service (S. Platt, Personal Communications, 2006).

On Form 7520-2A, Compliance Evaluation, Part V, Summary of Violations, includes summary data on the number of mechanical integrity violations (V.B.2), the number of operation and maintenance violations (V.B.3), and the number of monitoring and reporting violations (V.B.5).

Form 7520-2B, Compliance Evaluation Significant Noncompliance (SNC), Part V, Summary of Significant Non-Compliance (SNC), requests the total number of wells with mechanical integrity SNC Violations (V.B.2) and with injection pressure SNC violations (V.B.3).

Form 7520-4, Quarterly Exceptions List, tracks wells reported in SNC for two or more consecutive quarters. Wells with various types of violations, including mechanical integrity and injection pressure violations, are recorded.

While the information on the forms is tabulated by well Class, none of these national-level summary forms indicate what fluids are injected into the wells. It is not possible, therefore, to determine which wells might inject CO_2 as part of enhanced oil recovery. This does not enable comparisons of MIT failure characteristics between wells that do and those that do not inject CO_2.

Only DI programs are required to complete the 7520 forms. Primacy States may choose their method for compiling this information; however, some primacy States use the 7520 forms as well. This includes some large programs, such as California, Colorado, Illinois, New Mexico, Oklahoma, and Texas. Other States submit annual reports, which may or may not contain precisely the same information as the 7520 forms.

The summary 7520 forms are reviewed by Headquarters staff as they arrive. No systematic quality assurance (QA) checks or data verifications are performed, however. State and DI permit files have not been reviewed since the early 1990s. *Ad hoc* reviews of the 7520 forms have been performed in recent years, for example to compare this data with Program Activity Measures (PAM) data reported by the States, and to respond to inquiries about the UIC program PAM.

Exhibit 3: Summary of MIT Information Reported on 7520 Forms

Form	MIT Information Reported
7520-3	Total number of wells inspected and the number of various types of inspections performed, e.g., MITs witnessed, emergency response or complaint response inspections, well constructions witnessed, well pluggings witnessed, and routine/periodic inspections. Number of wells that passed and failed Part I (internal) and Part II (external) MITs. Remedial actions taken as a result of MIT failures.
7520-2A	Number of mechanical integrity violations, operation and maintenance violations, and monitoring and reporting violations.
7520-2B	Number of wells with mechanical integrity significant noncompliance (SNC) and with injection pressure SNC violations.
7520-4	Tracks wells reported in SNC for two or more consecutive quarters. Wells with various types of violations, including mechanical integrity violations, are included.

Other sources of MIT information

Program Activity Measures (PAMs). Through the PAM reporting process, EPA collects information on the mechanical integrity of Class I , II, and III wells. PAM SDW-14 measures separately, for each class of wells, the percentage of Class I, II, and III (salt solution mining) wells that maintain mechanical integrity. The information is not specific as to the type of MI failure and, like the 7520 forms, PAMs do not identify the fluids injected into the wells. This information was collected in FY 2003 and 2005.

State Data. Two sources of data available in at least some States are monitoring reports submitted by permittees and State electronic databases. These information sources may provide a link between MI and injectate data.

- *Injection Well Monitoring Reports*. Forms 7520-8 and 7520-11 (Class II-specific), collect individual permittee data on minimum, average, and maximum injection pressure, injection rate, annular pressure, injection volume (monthly total and yearly cumulative), temperature, and pH. These forms are not compiled nationally.

- *State Databases*. Many States maintain electronic databases to manage their UIC data. According to a recent study by EPA of the status of state database coverage, most Class II programs maintain MIT data in their state databases. More than 80 percent of Class II programs store information on MIT test types performed and the result; these programs collectively represent more than 90 percent of Class II wells. It is unclear how many of these can distinguish CO_2 wells from other wells in their databases, however.

b. Summary of Findings of 7520 Review

EPA reviewed the Class I and Class II information reported on a sample set of 7520 forms from FY 2004 and 2005. The review was of all 7520 forms for FY 2004 and FY 2005 submitted to date (December 2005) by Regions 1, 4, 6, 7, and 9. In general, the Class I/II data on forms 7520-2A, 7520-2B, and 7520-3 are somewhat incomplete. For example, many rows corresponding to certain violation or inspection types were blank on the forms. In FY 2005, Mississippi, Texas, Kansas, and California reported MI violations associated with Class I and Class II wells on 7520-4. Most States' forms indicated that no wells belonged on their exceptions list; that is, no wells were reported to be in significant non-compliance for two or more consecutive quarters.

Although some states compete the 7520 forms electronically, the summary 7520 information is submitted in paper form only, contains a great deal of data, and therefore national-level compilations are difficult. However, a review of the sample of FY 2005 forms reveals that MIT failure rates are low– the rate of MIT failures per active well was approximately two percent in FY 2005. Although this approximate rate is based on neither a census nor a statistical sample of Class I and II wells, it is consistent with the UIC "PAM" reporting effort.

No specific incidents of leakage were reported on the 7520 forms reviewed. Leakages to the surface (a potential threat associated with CO_2 injection) would not be reported on the 7520 forms. Forms 7520-2A and 7520-2B request the number of cases of alleged contamination of a USDW. Only one case was reported, from a Class II-D (brine disposal) well in Oklahoma.

c. Usefulness of 7520 Information

The MIT information is currently submitted on paper forms only, and is not electronically tabulated or compiled, making national level assessments of the data difficult (the forms record the number of wells that passed and failed each of 8 types of tests each year in each state). EPA Headquarters is considering the development of a national UIC database that would include well-level data, including fluids injected and MIT information. This database will not be operational until at least 2007, and may not be populated with data for all wells until long after that date.

Because the forms contain summary-level data only, there is no way to track whether MIT failures are occurring in wells that inject CO_2, or whether CO_2 wells experience MIT (or MI) failures more often than those injecting other fluids. For example, form 7520-3 includes a great deal of information about the number of wells that pass and fail each of the various types of MITs. However, because this is information summarized at the State-level, there is no way of knowing what fluids are injected into any of the wells with a given MIT result.

5. Experimental and Field Experience Regarding MIT and CO_2 Corrosion

Materials and techniques for controlling corrosion (such as corrosion resistant alloys, use of fiberglass liners, or more corrosion resistant cements) are in use and continue to be researched and developed through petroleum industry experience in CO_2 flooding (the use of CO_2 injection for enhanced oil recovery, EOR). As research continues, some studies report that experiments and field experience find corrosion rates that are lower than predicted by existing corrosion models (Seiersten and Kongshaug, 2005; Carey *et al.*, 2005).

Scherer *et al.*, (2005) conclude that in a typical depleted oil or gas reservoir considered for CO_2 storage, the CO_2 plume and/or acidified brine will encounter several hundreds of wells (including abandoned wells). The duration and intensity of exposure to the acidified brines will determine the rate of corrosion of the cement seals of the wells. The preliminary findings of their ongoing experimental study suggest that the risk of leakage due to acid corrosion will be high if flow through the well annulus continues to deliver fresh acidic brine into contact with well cement. Conversely, risk will be low if there is limited flow through the annulus. Based on their experimental study, Duguid *et al.* (2005) conclude that it is likely that the carbonated brines and subsurface conditions that may exist in a CO_2 storage site will damage the typical cement found in an abandoned well. They concluded that cement damage may occur in as little as seven days. In the absence of fresh brine, however, carbonation may occur, which actually acts to suppress the corrosion process (Carey *et al.,* 2005), possibly explaining the corrosion over-estimates of some models.

Recent research by Schlumberger (J. Tombari, Personal Communications, 2006) has found measured alteration of Portland cement in as little as 2 days in the presence of wet supercritical CO_2 fluid and also in CO_2-saturated water or brine under downhole pressure and temperature conditions. This research also found dissolution of latex in cement, suggesting that the addition of latex in cement is not recommended for corrosion inhibition.

Some field experiences of injecting CO_2 for EOR were recently described by Kinder Morgan Co., the company that owns and operates the West Texas SACROC Unit (Larkin, 2006). CO_2 flooding has occurred in this oil field for more than 30 years. Larkin (2006) notes that CO_2 corrosion is manageable and presents the wide variety of corrosion management measures the company can employ including fiberglass casing linings, cathodic protection, tailored (latex) cement, and, for well steel connections, coated connections, corrosion rings, and ultra flush connections. Industry research and development of corrosion-resistant materials remains very active.

Additional evidence of CO_2 corrosion of wellbores comes from observations of a possible emerging trend in so-called “CO_2 blowouts” in gas production wells. Publishing in WorldOil’s Online Magazine, Skinner (2003) reports that the cumulative effects of CO_2 corrosion may be becoming a problem in some old wells in CO_2 floods that were drilled many decades ago. Though the number of blowouts referred to by Skinner is just a handful, he suggests this specific type of CO_2 well corrosion may be an emerging problem.

(In addition to the integrity of the CO_2 injection wells, the integrity of converted oil and gas production wells and abandoned wells that penetrate a CO_2 injection and storage zone represent a concern regarding secure storage of CO_2. This is a related, but separate well integrity research issue, and is different from injection well integrity issues regarding CO_2 concentrations and the pressures, temperatures, and duration of CO_2 exposure. While new CO_2 injection wells can be constructed using appropriate materials for controlling corrosion, old production or abandoned wells more likely have components made of traditional materials that are more susceptible to corrosion. Tailored, corrosion-resistant cements may be considered for plugging wells, and if a production well is to be converted to a CO_2 injection well, it will be subject to any injection well permitting, construction, operation, and monitoring requirements.)

6. Summary and Conclusions

a. Summary of General MI Issues

- CO_2 corrosion of tubing, packers, casing, and cement for injection wells is a key injection well mechanical integrity issue related to well bore integrity and injection of CO_2 for geological sequestration.

- Experimental studies suggest that standard cements commonly used in current well construction (and abandonment) are susceptible to degradation under the conditions likely encountered in subsurface CO_2 storage.

- National information and data to support thorough national assessments of MIT results or MI performance is not readily available. Several EPA studies had been conducted and are summarized here, but MIT information is particularly limited and dated for the UIC Class II injection wells.

- Degradation of well materials can and does cause loss of well bore integrity, as based on the findings of the existing EPA studies. Higher rates of MIT failures for Class I hazardous waste injection wells (compared to Class I non-hazardous wells) are likely due to the more corrosive nature of the injectate.

- Mechanical integrity testing failures have decreased from the 1980s through the 1990s for Class I and Class II injection wells (i.e., injection well performance has improved).

- CO_2 corrosion control materials and measures are available, are currently in wide use for CO_2 injection for EOR projects, and continue to be developed and improved.

- Studies have identified injection (and abandoned) well bores as perhaps the primary potential conduits of leakage related to CO_2 geosequestration.

b. Summary of Class I Injection Well Findings

- The two existing Class I injection well studies, covering the period from 1988 to 1998, assessed MI and MIT records from nearly all of the approximately 540 Class I wells (100% of all hazardous waste injection wells and 75-85% of all non-hazardous waste injection wells).

- For essentially the same number of Class I wells, the number of internal MI failures decreased from 1988-1992 to 1993-1998.

- Internal MI failures were mainly due to tubing (37%), packer (21%), and casing (17%) failures from 1988 to 1992, and from tubing (37%), casing (34%), and packer (20%) failures from 1993 to 1998.

- Class I hazardous waste wells had a significantly higher proportion of internal MI failures than did Class I non-hazardous wells. This was presumably due to the more corrosive nature of the hazardous injectate.

- All internal MI failures were detected during operation with continuous annulus monitoring.

- Casing failures are somewhat more common in wells injecting hazardous waste than in wells injecting non-hazardous waste.

- None of the internal MI failures reported affected a USDW.

- External MI failures were relatively rare; there was one external MI failure in 1988-1992 and six external MI failures reported in 1993-1998.

- There were no reported cases of MI failures affecting USDWs. (There were 26 cases of reported migration out of the injection intervals, including 10 possible cases in Florida affecting USDWs. All these cases are associated with municipal wastewater injection and may be the result of migration through natural fractures away from the wellbore. The buoyancy-driven fluid movement aspects of the Florida cases may be relevant to similar buoyancy considerations for injection and long-term storage of buoyant CO_2.)

c. Summary of Class II Injection Well Findings

- Class II injection well MIT information is very limited.

- The existing Class II injection well study, covering the period from 1983 to 1991, was based on an analysis of results from nearly 10,000 MITs conducted in four states (PA, MI, LA, NE; the representativeness of the Class II well MI performance of these four States is not known).

- The overall Class II MIT failure rate was 10.5% (the study did not distinguish between internal and external MI). The failure rates for the four States ranged from 3% to 12%. (If all test failures are included, such as those from testing conducted before the scheduled, formal MITs, the failure rate reported might increase by 50%.)

- The records of the types of MIT failures are very incomplete (only 46% of records identified the reason for MIT failure). Of these, 54% identified casing failure, 25% tubing failure, and 19% packer failure.

- Casing failures accounted for the highest portion of MIT failures in Pennsylvania (81%), where all the MITs reviewed were for Class II injection wells for enhance oil recovery (though this number includes the performance of older “grandfathered” that were being phased out of service).

- About 20% of the wells with casing failures were completed without tubing and packers, so migration outside the wellbore was possible.

d. Conclusions, Information Gaps, and Research Questions

- Maintaining and monitoring injection well mechanical integrity is a key component of the successes of the Class I and Class II injection well programs.

- Injection well mechanical integrity is a concern for CO_2 injection and sequestration due to CO_2 corrosion of injection well materials.

- Numerous corrosion control measures are in use for CO_2 injection for EOR, and industry continues to conduct considerable research to identify appropriate CO_2 corrosion-resistant materials and measures.

- The MI performance of Class II wells used for enhanced oil recovery, especially those wells that inject any CO_2, could provide the most directly relevant information for assessments of planned CO_2 injection wells and well bore integrity.

- Existing, readily available information on mechanical integrity tests for Class II wells is limited, incomplete, and dated. Given the large number of Class II wells and the fact that at least some inject CO_2 for EOR, additional data on the performance of Class II well MITs would enable a more empirical and fuller characterization of CO_2 injection well performance.

- Other MIT information is contained in the "7520" forms submitted to EPA, but these forms contain some what incomplete, summary-level data only. Using these forms, it is not possible to conduct detailed characterizations of MIT failures in Class II wells that inject CO_2, and not possible to determine whether those wells experience MI failures more than, less than, or about the same as wells injecting other fluids.

- If warranted, closer examinations of operator-specific 7520 forms for Class II EOR wells may provide a more complete inventory and characterization of MIT results for those wells injecting CO_2 for enhanced oil recovery. States with the greatest number of Class II wells likely have the most data relevant to more fully compare and characterize MIT performance for wells that do and do not inject CO_2. (State electronic data bases are estimated to contain information on perhaps 90% of Class II wells.)

- Many states have adopted or are in the process of adopting a GWPC-created database called the Risk-Based Data Management System (RBDMS) to manage data on their Class II injection wells and oil and gas producing wells. Much more detailed information, therefore, is potentially available for these wells. (However, not all states necessarily maintain data on the composition of the injected fluid, so data specific to CO_2 injection may not be readily available.) However, the RBDMS databases are customized and managed by the individual States, and EPA does not have a national, comprehensive database.

- The sharing of well performance and mechanical integrity information between industry and government (EPA, DOE) may provide the most directly relevant and useful information necessary for a well-informed and transparent development of CO_2 injection regulations for full-scale commercial sequestration operations.

Some specific research questions may include:

- How do the MIT failure rates for CO_2 EOR wells compare to other Class II wells?

- Do Class II wells that inject CO_2 fail certain types of MITs more or less often than others?

- Have any Class II wells that inject CO_2 experienced leakages along the borehole either to the surface, or into USDWs or other formations?

- Would CO_2 injection well mechanical integrity testing requirements (procedural- or performance-based) be an appropriate mechanism to mitigate risks of CO_2 releases by monitoring injection well performance? (One example ancillary question: is the provision of well cement logs to demonstrate Class II well external mechanical integrity, in lieu of other well logs, appropriate for CO_2 injection wells given the corrosive nature and long-term storage concerns of CO_2 geosequestration?)

- Would CO_2 injection well construction standards (procedural- or performance-based) for appropriate corrosion-resistant materials and measures be an effective mechanism for addressing concerns and risks associated with loss of injection well mechanical integrity related to CO_2 corrosion?

References

Barlet-Gouedard, V., G. Rimmele, B. Goffe, and O. Porcherie (2006). "Mitigation strategies for the risk of CO_2 migration through wellbores." Presented at the IADC/SPE Drilling Conference in Miami, Florida, February 2006.

Browning, L.A. (The Cadmus Group, Inc.) and J.B. Smith (USEPA). 1993. "Analysis of the Rate of and Reasons for Injection Well Mechanical Integrity Test Failure." Presented at SPE/EPA Exploration and Production Environmental Conference, March 7-10, 1993, San Antonio, TX.

Bruckdorfer, R.A. 1986. "Carbon Dioxide Corrosion in Oilwell Cements." Presented at SPE Rocky Mountain Regional Meeting, May 19-21, Billings, MT.

Carey, B., G. Guthrie, P. Lichtner, R. Pawar, S. Wehner, and M. Raines. 2005. "Character of the Well-Bore Seal at 49-6 in the SACROC Reservoir, West Texas." Presented at the IEA Well Bore Integrity Workshop, April 4-5, 2005.

Christopher, C.A., C.E. Fox, and S.M. Avasthi. 2005. "Geological Sequestration of CO2." SPE Short Course presented November 29-30, 2005 at USEPA Offices in Dallas, TX.

Duguid, A., M. Radonjic, R. Bruant, T. Mandecki, G. Scherer, and M. Celia. 2005. The Effect of CO_2 Sequestration on Oil Well Cements. In *Proceedings of 7th International Conference on Greenhouse Gas Control Technologies,* September 2004, Vancouver, BC.

Imbus, S. and C. Christopher. 2005. Key Findings, Technology Gaps and the Path Forward. Chapter 34 in S. Benson (ed.), *The CO_2 Capture and Storage Project (CCP) for Carbon Dioxide Storage in Deep Geologic Formations for Climate Change Mitigation, Vol. 2.* Elsevier, London, UK.

Intergovernmental Panel on Climate Change (IPCC). 2005. IPCC Special Report on Carbon Dioxide Capture and Storage, Including the Final Draft Summary for Policymakers for Government Review. July 25, 2005.

International Energy Agency (IEA). 2005. Report on Well Bore Integrity Workshop, IEA Greenhouse Gas R&D Programme, April 2005

Larkin, R. 2006. "Carbon Capture & Geologic Storage: From Science to Regulation." Presented at the GWPC UIC Conference, January 2006, Austin, TX.

Nicot, J-P, S.D. Hovorka, P.R. Knox, and T. Naing. 2006. "Area of Review: How large is large enough for carbon storage?" Presented at the GWPC UIC Conference, January 2006, Austin, TX.

Scherer, G.W., M.A. Celia, J-H Pre´vost, S. Bachu, R. Bruant, A. Duguid, R. Fuller, S.E. Gasda, M. Radonjic, and W. Vichit-Vadakan. 2005. Leakage of CO_2 Through Abandoned Wells: Role of Corrosion of Cement. Chapter 10 in S. Benson (ed.), *The CO2 Capture and Storage Project (CCP) for Carbon Dioxide Storage in Deep Geologic Formations for Climate Change Mitigation, Vol. 2.* Elsevier, London, UK.

Seiersten, M. and K.O. Kongshaug. 2005. Materials Selection for Capture, Compression, Transport and Injection of CO_2. Chapter 16 in S. Benson (ed.), *The CO2 Capture and Storage Project (CCP) for Carbon Dioxide Storage in Deep Geologic Formations for Climate Change Mitigation, Vol. 2.* Elsevier, London, UK.

Shen, J.C. and D.S. Pye. 1989. "Effects of CO_2 Attack on Cement in High-Temperature Applications." Presented at SPE/IADC Drilling Conference, February 28-March 3, New Orleans, LA.

Skinner, Les. 2003. "CO_2 Blowouts: An Emerging Problem." WorldOil.com – Online Magazine Article: Special Focus, January 2003.

Tombari, J. 2006. Personal Communication.

Underground Injection Practices Council (UIPC). 1987. *A Class I Injection Well Survey (Phase II Report): Survey of Operations*. December 1987.

USEPA. 1993. *Class I Well Failure Analysis: 1988-1991.* Prepared by The Cadmus Group for OGWDW, UIC Branch in response to Question 4 in Congressman John D. Dingell's letter to William K. Reilly, dated October 22, 1992, regarding disposal of hazardous wastes, deep injection, and underground wells at 42 U.S.C. section 6924 (F) - (G). March 5, 1993.

USEPA, Inc. 1999. *Class I Mechanical Integrity Failure Analysis: 1993-1998.* Prepared by ICF, Inc., Fairfax, Virginia, for USEPA, OGWDW, UIC Branch. September 1999.

USEPA. 2002. "Technical Program Overview: Underground Injection Control Regulations." EPA Report 816-R-02-025, December 2002.

U.S. General Accounting Office (GAO). 1987. *Hazardous Waste–-Controls over Injection Well Disposal Operations*.