United States Environmental Protection Agency

# Cost Analysis for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (Final GS Rule)

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# List of Acronyms

| | |
|---|---|
| AAPG | American Association of Petroleum Geologists |
| AoR | Area of Review |
| API | American Petroleum Institute |
| ASTM | American Society for Testing and Materials |
| BLS | Bureau of Labor Statistics |
| CCS | Carbon Capture and Storage |
| CFR | Code of Federal Regulations |
| CIR | Color Infrared Orthoimagery |
| $CO_2$ | Carbon Dioxide |
| CSLF | Carbon Sequestration Leadership Forum |
| DOE | Department of Energy |
| ECBM | Enhanced Coal Bed Methane |
| EO | Executive Order |
| EPA | United States Environmental Protection Agency |
| ER | Enhanced Oil and Gas Recovery |
| FR | Federal Register |
| G&A | General and Administrative |
| GIS | Geographic Information System |
| GS | Geologic Sequestration |
| Gt | Gigatons |
| GWPC | Ground Water Protection Council |
| ICR | Information Collection Request |
| IOGCC | Interstate Oil & Gas Compact Commission |
| IPCC | Intergovernmental Panel on Climate Change |
| IZ | Injection Zone |
| LBNL | Lawrence Berkley National Laboratories |
| LIDAR | Light Detection and Ranging |
| MI | Mechanical Integrity |
| MIT | Mechanical Integrity Testing |
| MMV | Measurement, Monitoring, and Verification |
| NAICS | North American Industry Classification System |
| NATCARB | National Carbon |
| NETL | National Energy Technology Laboratory |
| NGO | Non-governmental Organization |
| NODA | Notice of Data Availability |
| NTTAA | National Technology Transfer and Advancement Act |
| O&M | Operation and Maintenance |
| OAL | Oxygen Activation Log |
| OMB | Office of Management and Budget |
| OPM | Office of Personnel Management |
| PBMS | Performance Based Measurement System |
| PISC | Post-injection Site Care |
| PRA | Paperwork Reduction Act |
| PV | Present Value |
| RA | Regulatory Alternative |

| | |
|---|---|
| RCSP | Regional Carbon Sequestration Partnership |
| RFA | Regulatory Flexibility Act |
| SBA | Small Business Association |
| SBREFA | Small Business Regulatory Enforcement Fairness Act |
| SDWA | Safe Drinking Water Act |
| SOC | Standard Occupational Classification |
| SPE | Society for Petroleum Engineers |
| TDS | Total Dissolved Solids |
| UIC | Underground Injection Control |
| UMRA | Unfunded Mandates Reform Act |
| USDW | Underground Source of Drinking Water |

# 1. Introduction

This Cost Analysis evaluates the costs and potential benefits of the new Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide ($CO_2$) Geologic Sequestration (GS) Wells (the GS Rule). Executive Order (EO) 12866, *Regulatory Planning and Review* (58 FR 51735) requires the United States Environmental Protection Agency (EPA) to estimate the economic impact of rules that have an annual effect on the economy of over $100 million and make that analysis available to the public in conjunction with publication of the final rule. EPA has chosen to publish a comprehensive cost analysis and a relative risk analysis to accompany the GS rule even though the Agency has determined that the annual cost is below the $100 million threshold. These analyses consider both the relative costs of the regulatory alternatives and the reduction in risk relative to baseline provided by each alternative in selecting the final rule.[1]

The final GS rule establishes minimum Federal requirements under the Safe Drinking Water Act (SDWA) for injection of $CO_2$ for the purposes of long-term storage (also known as GS). The final rule creates a new class of injection well, Class VI, and sets minimum technical criteria for the purposes of protecting underground sources of drinking water (USDWs). The elements of the GS Rule are based on the existing Underground Injection Control (UIC) regulatory framework with modifications to address the unique nature of GS in the anticipation of its eventual use to reduce $CO_2$ emissions to the atmosphere.

An outline of the organization of this Cost Analysis is provided below. The remainder of this chapter summarizes the technical, regulatory, and public health issues addressed by the final rule (Section 1.1) and provides an overview of the UIC Program regulatory framework on which the rule is based (Section 1.2). It also explains the statutory authority for the rule and the economic rationale for adopting a regulatory approach (Section 1.3).

The remainder of this cost analysis is organized into the following chapters:

- Chapter 2 presents a review of the alternative regulatory approaches EPA considered during development of the GS rule and the rationale for selecting the minimum requirements that comprise the final rule.

- Chapter 3 characterizes conditions that exist prior to promulgation of the GS rule. It includes a profile of hydrogeologic settings available for GS and potential $CO_2$ storage capacity. It also provides projection estimates of the number and types of GS projects likely to be affected by the rule.

[1]EPA developed a relative risk analysis in place of a quantified assessment of risk because GS is a new technology and the results from research on the potential effects of GS on underground sources of drinking water (USDWs) are not yet available.

- Chapter 4 presents a discussion of the risk and benefit tradeoffs between compliance with existing UIC regulations and the four regulatory alternatives considered. A qualitative discussion of the potential economic benefits of the final rule is also presented.

- Chapter 5 presents an estimate of the costs of implementing the final rule to owners and operators and primacy agencies. The costs of the other regulatory alternatives that were considered are compared.

- Chapter 6 discusses the effects of the GS rule on different segments of the population and considers the executive orders and requirements applicable to this rulemaking, including the Regulatory Flexibility Act (RFA) and Unfunded Mandates Reform Act (UMRA).

- Chapter 7 lists references cited in Chapters 1 - 6.

This Cost Analysis presents results from detailed and complex analyses. To help the reader track the various calculations and analyses, the following are provided:

- Appendices

  - Appendix A presents the characteristics that factor into costs for each pro forma (representative project type) case.

  - Appendix B presents a matrix that includes the algorithms that define unit costs for different regulatory components, and an application factor that describes the extent to which each cost applies under each regulatory alternative.

  - Appendix C presents detailed cost spreadsheets that are output from the cost model for each of the regulatory alternatives considered in this cost analysis.

- Exhibits - Most tabular exhibits include a row that provides the formulas used to calculate the contents of each column.

- Sources for information that is used, but not calculated within the exhibits.

- Supporting electronic file output (i.e., GS rule cost model output).

## 1.1 Technical, Public Health, and Regulatory Issues Addressed by the GS Rule

The Agency has developed a final rule that has tailored the existing UIC regulatory framework to address the unique nature of $CO_2$ injection for GS for the purposes of protecting USDWs. The rule contains tailored requirements for the following criteria:

1. Site Characterization,

2. Area of Review and Corrective Action,

3. Injection Well Construction,

4. Injection Well Operation,

5. Mechanical Integrity Testing,

6. Monitoring,

7. Injection Well Plugging, Post-injection Site Care (PISC) and Site Closure,

8. Financial Responsibility, and

9. Emergency and Remedial Response.

### 1.1.1 Description of the Issue

Geologic sequestration is the process of injecting $CO_2$ captured from an emissions source (e.g., a power plant or industrial facility) into deep subsurface rock formations for long-term storage to reduce $CO_2$ emissions to the atmosphere. To inject captured $CO_2$, the $CO_2$ is typically converted from a gaseous state to a supercritical state. The $CO_2$ is then delivered from the source to the GS site where it is injected into deep subsurface rock formations (such as deep saline formations and oil and gas reservoirs) via an injection well.

Many of the injection and monitoring technologies that may be applicable to GS are commercially available today and are being used by the oil and gas industry for enhancing oil and gas production. However, these technologies have yet to be widely demonstrated at the larger scale needed for GS. It is expected that GS projects will inject large volumes of $CO_2$. $CO_2$ in the subsurface is buoyant and is highly mobile. While $CO_2$ itself is not a drinking water contaminant, $CO_2$ in the presence of water forms a weak acid and can cause leaching and mobilization of naturally-occurring metals and/or other contaminants from geologic formations into groundwater if injection wells are not properly sited, operated and monitored. The GS Rule provides minimum requirements to protect USDWs from endangerment as this climate mitigation technology is developed and deployed.

Experimental field research on GS in the U.S. is being led by the Department of Energy (DOE) under the Regional Carbon Sequestration Partnerships (RSCPs) program. In recent years, several experimental pilot or demonstration projects for GS have come into operation or have completed injection. Before promulgation of this rule, these projects were permitted under the existing UIC Program regulations as either Class V experimental technology wells[2], Class I industrial non-hazardous waste injection wells (the baseline scenario for this cost analysis), or Class II injection wells (where the $CO_2$ injection is associated with oil or gas recovery). Following promulgation of the GS Rule, projects whose primary purpose is to inject $CO_2$ for long-term storage will be permitted as Class VI.

[2] This classification is appropriate for experimental GS projects, and is addressed in EPA's March 2007 *UIC Program Guidance # 83: Using the Class V Experimental Technology Well Classification for Pilot Carbon Geologic Sequestration Projects*.

For the purpose of developing the baseline estimate of projects to deploy as required for the cost analysis, EPA considered the current legislative environment only, as recommended in EPA's *Guidelines for Preparing Economic Analysis* (USEPA, 2000). EPA acknowledges that if legislation is passed that limits $CO_2$ emissions to the atmosphere in the future, it will create an economic incentive for more projects to deploy. Although GS is occurring now on a relatively small scale, it could play a larger role in mitigating $CO_2$ emissions from a variety of stationary sources. For example, 95 percent of the 500 largest stationary sources are located within 50 miles of a candidate GS reservoir (Dooley et al., 2006).

While predictions about large-scale availability and the rate of GS deployment are subject to considerable uncertainty, EPA analysis of Congressional climate change legislative proposals indicate that GS has the potential to play a significant role in climate change mitigation scenarios. EPA's summary of this analysis is provided in the preamble cost section (Section IV) of the final rule. In addition, because of this uncertainty in the actual number of projects expected to deploy over the period of this analysis (2011-2060), EPA conducted sensitivity analyses reflecting projections under certain current legislation or policy positions. Chapter 5 of this Cost Analysis presents a sensitivity analysis that considers costs for 5 and 54 projects as the lower and upper bound number of projects deployed. These analyses are comparable to analyses performed to support the Regulatory Impact Analysis for Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of CO2 Rule (Subpart RR) [3].

### 1.1.2 Public Health Concern to Be Addressed

The injection of $CO_2$, if not properly managed, could endanger USDWs because the large injection volumes expected, the relative buoyancy of $CO_2$ and its potential mobility within subsurface geologic formations, combined with the corrosive nature of $CO_2$ in the presence of water, could mobilize contaminants from the surrounding formations and decrease pH of the groundwater. In addition, large injection volumes could push saline ground water into fresh water sources.

Such changes to ground water quality could compromise drinking water quality, requiring treatment to make the water potable, and in some cases resulting in the inability to produce potable water (e.g., where the cost of treatment is prohibitive). The GS rule will protect USDWs by requiring that appropriate measures related to proper siting, injection well construction and operation, monitoring and testing, plugging, PISC, and site closure that mitigate the risks to USDWs be implemented for all GS wells.

[3] Simultaneous development of the Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of $CO_2$ Rule (Subpart RR) and the GS Rule was coordinated by EPA. As a part of the coordinated rule making efforts, EPA developed these sensitivity analyses to ensure consistency of requirements and costs between the two rules.

### 1.1.3 Statutory Authority for Promulgating the Rule

The GS rule is focused on USDW protection under the authority of Part C of SDWA (SDWA § 1421 et seq., 42 U.S.C. 300h et seq.) and applies to injection wells in the U.S., including those in State territorial waters.

SDWA is designed to protect the quality of drinking water sources in the U.S. and prescribes that EPA issue regulations for State[4] UIC Programs that contain "minimum requirements for effective programs to prevent underground injection which endangers drinking water sources." Congress further defined endangerment as follows:

> Underground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons (SDWA §1421(d)(2)).

Under this authority, the Agency has promulgated a series of UIC regulations at 40 CFR Parts 144 through 148 for Federally approved UIC programs. The chief goal of any Federally approved UIC Program (whether administered by a State, Territory, Tribe or EPA) is the protection of USDWs. This includes not only those formations that are presently being used for drinking water, but also those that can reasonably be expected to be used in the future. EPA has established through its UIC regulations that USDWs are underground aquifers with less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) and which contain a sufficient quantity of ground water to supply a public water system (40 CFR 144.3). Section 1421(b)(3)(A) of the SDWA also provides that EPA's UIC regulations shall "permit or provide for consideration of varying geologic, hydrological, or historical conditions in different States and in different areas within a State."[5]

Under the SDWA, the injection of any "fluid" is subject to the requirements of the UIC Program. A "fluid" is defined under §144.3 as any material or substance that flows or moves whether in a semisolid, liquid, sludge, gas or other form or state, and includes the injection of liquids, gases, and semisolids (i.e., slurries) into the subsurface. Examples of the fluids currently injected into wells subject to UIC requirements include: $CO_2$ for the purposes of enhancing recovery of oil and natural gas, water that is stored to meet water supply demands in dry seasons, and wastes generated by industrial users. $CO_2$ injected for the purpose of GS is subject to the SDWA.

[4] Reference to "States" includes Tribes and Territories.

[5] The Federal codes under which EPA promulgated these administrative and permitting regulations and associated dates of passage are described in the Preamble for the GS rule.

## 1.2 Regulatory History

When EPA initially promulgated its UIC Program regulations, it defined five classes of injection wells based on similarities in the fluids injected, construction, injection depth, design, and operating techniques. This categorization ensures that wells with common design and operating techniques are required to meet appropriate performance criteria and is described in the following paragraph.

Class I wells, which inject hazardous wastes, industrial non-hazardous liquids, or municipal wastewaters beneath the lowermost USDW, are technically sophisticated and subject to stringent construction and operation standards. Class II wells inject fluids (including $CO_2$) associated with oil and gas production. Class III wells inject fluids associated with solution mining of minerals. Class IV wells inject hazardous or radioactive wastes into or above USDWs.[6] Class V includes all injection wells that are not included in Classes I-IV. In general, Class V wells inject non-hazardous fluids into or above USDWs; however, there are some deep Class V wells that inject below USDWs. Class V wells include GS experimental technology wells used for GS pilot projects.

Currently, almost all existing $CO_2$ injection in the U.S. involves Class II wells (for oil and gas production purposes) and Class V experimental technology wells, with a very limited amount involving Class I wells:

- For the past several decades $CO_2$ has been injected via Class II wells for enhanced oil and gas recovery (ER). In ER operations, $CO_2$ is injected to make the residual oil in a reservoir more mobile and facilitate recovery. Class II well operators and permitting authorities have decades of expertise with injection, including injection of $CO_2$ for the purposes of oil and gas production, with oil and gas reservoir dynamics, and with injection well construction. Although the majority of $CO_2$ is likely to be injected into saline formations over the long term, it is anticipated that, given the experience and the availability of background data and infrastructure related to Class II injection, many Class II projects will want to transition to long-term storage projects in oil and gas reservoirs early in the deployment phase.

- Over the past decade, pilot-scale projects began injecting small volumes of $CO_2$ to test GS technologies and inform EPA's final decision on how to regulate GS activities. To allow permitting of pilot-scale GS projects in advance of a GS rulemaking, EPA issued guidance to assist State and EPA regional UIC Programs in processing permit applications for pilot and other small-scale experimental GS projects. In the *UIC Program Guidance # 83: Using the Class V Experimental Technology Well Classification for Pilot Carbon Geologic Sequestration Projects* (USEPA, 2007), EPA recommends that pilot GS projects be permitted as Class V experimental technology wells. The guidance applies to pilot $CO_2$ injection projects of an experimental nature that are designed to assess the efficacy of $CO_2$ injection for the purposes of long-term GS.

[6] Class IV wells are currently banned unless authorized under an approved Federal or State ground water remediation project.

The final rule defines a new class of injection well (Class VI) that is specifically tailored to injection of $CO_2$ into deep subsurface formations for long-term storage.

## 1.3 Economic Rationale

This section addresses the economic rationale for choosing a regulatory approach to govern GS and thus protect public drinking water supplies (i.e., by protecting USDWs) rather than nonregulatory alternatives. Although the final rule is not subject to the requirement (including provision of an economic rationale) of EO 12866, *Regulatory Planning and Review* (58 FR 51735) for an economic rationale for the rule because it is not economically significant, EPA is providing the rationale below.

EO 12866 states the following:

> [E]ach agency shall identify the problem that it intends to address (including, where applicable, the failures of the private markets or public institutions that warrant new agency action) as well as assess the significance of that problem. (Section 1, b(1))

In addition, Office of Management and Budget (OMB) Circular A-4, dated September 17, 2003, states that "…[the analyst] should try to explain whether the action is intended to address a significant market failure or to meet some other compelling public need such as improving governmental processes or promoting intangible values such as distributional fairness or privacy." (OMB, 2003).

In the case of large-scale GS, two major types of market failures are present—the presence of externalities (related to the nature of the affected resources facing complex property rights issues and being generally regarded as public goods); and information asymmetry between GS injection well operators and potentially affected public water systems and private well users. These market failures work separately and together to distort the workings of a free market. Furthermore, the promulgation of a regulation that limits $CO_2$ emissions during the period of this analysis would exacerbate these market failures based on the expected increase in GS projects and amplification of the issues described below.

The presence of externalities is the first market failure, resulting from the nature of the affected resources. In this case, there are two resources that will be potentially affected by injection of $CO_2$ under the final rule—the aquifers that serve as USDWs and the underground formations that can sequester $CO_2$. Under the SDWA, EPA protects USDWs for public use and establishes a regulatory structure (the UIC Program) to prevent potential contamination that supersedes property rights/ownership issues. Because the UIC Program focuses specifically on protection of USDWs, there exists less regulatory history in defining ownership/property rights for underground formations not containing viable drinking water resources. Because of the complexity in defining property rights for non-USDW underground formations, for the purpose of this analysis non-USDWs are treated consistently with the treatment of USDWs, i.e., they are regarded as public goods. As public goods, the potential side effects from the operation of GS wells (i.e., contamination of USDWs or other underground formations due to improper siting, construction, operation, or closure) would likely be uncompensated by those responsible for such

contamination in absence of the UIC Program regulations. The costs of the final GS Rule as presented in this analysis represent the costs for the additional protection of USDWs provided by the Class VI regulation, which tailors protective measures to the risks posed by GS projects.

The second market failure results from an asymmetry in information held by GS well owners and operators versus potentially affected public water system and private well users. There are an estimated 105,249 smaller public water systems in the United States out of a total of 153,530 public water systems (USEPA, 2005a). This estimate includes Transient and Non-Transient Non Community Water Systems and Community Water Systems serving fewer than 1,001 customers. Additionally, many families in rural communities operate private wells. All of these systems and individuals would be at a disadvantage in trying to maintain a quality water supply if they were not informed of the potential risks that a GS project in their community might pose to their current or future potential water supplies. However, GS by nature is complex. The potential risk for water quality changes may be difficult to convey in a meaningful way to the large number of people that could be affected, i.e., those who are current and potential future consumers of the water from the aquifers under consideration, and the large associated transaction costs in educating a large number of people in a complex, nuanced discussion of GS.

The SDWA provides a level of protection from exposure to drinking water contaminants for which consumers may not be in a position to advocate for themselves. SDWA regulations are not intended to restructure market mechanisms or to establish competition in supply; rather, they establish minimum performance requirements and the level of service to be provided that best reflect public preferences for protectiveness. The Federal regulations reduce the high information and transaction costs by acting on behalf of consumers in balancing risk reduction and the social costs of achieving this risk reduction.

Two of the major types of market failures are present in the implementation of GS operations and are interrelated. USDWs and other injection formations are generally considered public goods which subject them to potential adverse externalities without a non-market intervention. Further, the complex nature of GS and the potential resulting water quality issues may be difficult to convey in a meaningful way to the potentially affected water systems with an amount of effort that is reasonable for both sides. These market failures distort the workings of a free market and are the basis for governmental intervention. Congress acknowledged these market conditions when it established a Federal regulatory approach to protecting USDWs under SDWA.

# 2. Consideration of Regulatory Alternatives

## 2.1 Introduction

The United States Environmental Protection Agency (EPA) is finalizing minimum Federal Requirements under the Safe Drinking Water Act (SDWA) for underground injection of carbon dioxide ($CO_2$) for the purposes of Geologic Sequestration (GS Rule). The GS Rule was developed to ensure consistency in permitting underground injection of $CO_2$ at geologic sequestration (GS) operations across the U.S. and provide requirements to prevent endangerment of underground sources of drinking water (USDWs) in anticipation of the eventual use of GS to reduce $CO_2$ emissions to the atmosphere. This cost analysis has been informed by Federal and non-Federal entities to determine how best to tailor existing underground injection requirements for $CO_2$ for GS (described in Section 2.2). Four regulatory alternatives (RAs) (see Section 2.3) were developed for managing the risks to USDWs associated with GS. Benefits and costs are estimated for each of the regulatory alternatives in this Cost Analysis. EPA selected an alternative (RA3) as the final GS Rule, which is described in Section 2.4 of this chapter.

## 2.2 Process for Development of Regulatory Alternatives

The GS Rule builds upon longstanding programmatic requirements that have been in place since the 1980s and are used to manage over 800,000 injection wells nationwide. EPA has taken a number of steps to inform the GS rule including: conducting research; conducting stakeholder coordination and outreach (including technical workshops); issuing a proposed rulemaking and soliciting and reviewing public comment; and publishing a Notice of Data Availability (NODA) for comment to seek additional input on the rulemaking.

The following workshops were held to identify technical, administrative, and regulatory issues associated with pilot and large-scale GS projects:

- *Measurement, Monitoring, and Verification (MMV) Workshop*. On January 16, 2008 EPA held a technical workshop on MMV in New Orleans, LA. The workshop included presentations by industry, academic, and government researchers on their experience with and use of subsurface and near-surface monitoring techniques. The presentations were followed by "round table" breakout discussions where participants discussed the availability and utility of various monitoring techniques that may be applicable to GS projects.

- *Geologic Setting and Area of Review Considerations Workshop*. EPA held a technical workshop in Washington, D.C. on July 10 and 11, 2007 to discuss geologic considerations and Area of Review (AoR) issues related to GS. The workshop consisted of three presentation sessions, during which industry and government experts described current research on: subsurface geologic information needed to determine whether a site is appropriate for GS, the role of artificial conduits in the AoR on siting decisions, factors that affect the size and shape of the AoR, and corrective actions to address wells in the AoR. To conclude the workshop, a panel of experts representing the Regional Partnerships and Interstate Oil & Gas Compact Commission (IOGCC) presented their experiences with pilot and experimental GS projects.

- *Well Construction and Mechanical Integrity Testing Workshop (MIT).* EPA held a technical workshop in Albuquerque, New Mexico on March 14, 2007 to address well construction and MIT issues related to GS. The workshop format included technical presentations on current research by industry, academia, and government agencies on experimental research in the U.S. and Canada into wellbore integrity and $CO_2$-cement interactions, modeling, the impact of wellbore integrity on GS site selection, and industry research on well construction.

- *State Regulators' Workshop on Geologic Sequestration of $CO_2$.* At the Ground Water Protection Council's (GWPC) UIC Technical meeting in San Antonio, Texas on January 24, 2007, EPA and DOE collaborated on a workshop to discuss and formulate the questions related to $CO_2$ injection that EPA would need to answer in its rulemaking process. In sessions led by the National Energy Technology Laboratory (NETL), experts presented the status of Department of Energy (DOE) research projects on AoR studies, injection well management, and MMV.

- *International Symposium on Site Characterization for $CO_2$ Geologic Storage.* Participants at this symposium, held in Berkeley, CA on March 20-22, 2006, discussed various aspects of characterization and selection of potential $CO_2$ storage sites. The symposium emphasized advances in process understanding, development of measurement methods, identification of key site features and parameters, site characterization strategies, and case studies. The presentations and discussions addressed: site characterization methods; regional-scale site selection; site characterization case studies; leakage from storage formations, including pathways, effects, and implications for site characterization; fundamental processes and technical issues related to site characterization; screening and characterization tools; and regulatory and social issues.

- *Risk Assessment for Geologic $CO_2$ Storage Workshop.* Following the GWPC fall meeting in Portland, Oregon, State and EPA experts on GS, ground water and underground injection, and health and environmental effects of $CO_2$ met on September 28-29, 2005. They discussed the development of a risk assessment framework to identify potential risks and to consider relevant field experience that could be applicable to injection and long-term storage of $CO_2$. Some of the key topics addressed at the workshop were abandoned wells, faults, and ground water displacement. Participants discussed key issues in conducting a risk assessment of geologic carbon storage.

- *Modeling and Reservoir Simulation for Geologic Carbon Storage Workshop*. On April 6-7, 2005, EPA held a workshop for 60 EPA headquarters and regional staff in Houston, Texas to assess the potential application of reservoir models and reservoir simulation to GS and to provide EPA with information about the 'state of the art' in the development and application of modeling approaches and numerical simulators for geologic $CO_2$ storage. They also discussed the role of models and reservoir simulation in supporting risk assessment and risk communication for GS sites. The workshop informed EPA about ways that geologic models and reservoir simulation might be applied during key stages in the life cycle of a $CO_2$ storage reservoir, from site selection and characterization through injection operations and post-injection verification of $CO_2$ containment.

Throughout the rulemaking process, the Agency conducted public workshops and public hearings, consultations with specific groups, and EPA representatives attended meetings to explain the GS rulemaking effort to interested public and stakeholder groups.

EPA held public meetings to discuss EPA's rulemaking approach, and consulted with other stakeholder groups including non-governmental organizations (NGOs) to gain a better understanding of stakeholder interests and concerns. As part of this outreach, EPA conducted two stakeholder workshops with participants from industry, environmental groups, utilities, academia, States, and the general public. These workshops, held in December 2007 and February 2008. EPA also specifically targeted outreach and consultation efforts to engage States and Tribes.

EPA has also been monitoring ongoing GS research and work by academia, the Intergovernmental Panel on Climate Change (IPCC), and World Resources Institute's Carbon Capture and Storage (CCS) working group.

*Agency Activities Conducted for Proposed Rulemaking*

On July 25, 2008, EPA published the proposed "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide ($CO_2$) Geologic Sequestration (GS) Wells" (73 FR 43492). The Agency proposed a new class of injection well (Class VI), along with technical criteria for permitting GS wells that tailored the existing UIC regulatory framework to address the unique nature of $CO_2$ injection for GS.

During the public comment period, the Agency held public hearings on the proposed rule in Chicago, IL on September 30, 2008 and in Denver, CO on October 2, 2008. The two hearings collectively drew approximately 100 people representing non-governmental organizations, academia, industry, and other organizations. At the hearings, 29 people submitted oral comments. Transcripts of the public hearings are in the rulemaking docket (Docket ID Nos. EPA-HQ-OW-2008-0390-0185 and EPA-HQ-OW-2008-0390-0256).

Based on public comments received on the proposed rule, the Agency identified several topics upon which it needed additional public comment. On August 31, 2009, EPA published supplemental information related to geologic sequestration in a NODA (74 FR 44802). The NODA presented new data and information from the DOE's NETL, including preliminary field data from the DOE-sponsored Regional Carbon Sequestration Partnership (RCSP) projects. The Notice presented the results of GS-related studies conducted by the Lawrence Berkeley National Laboratory (LBNL) concerning both GS projects and modeling to predict the potential impacts on ground water from GS activities (discussed in section II.C.2 of today's publication). The NODA also presented an alternative to address public comments and concerns about the proposed injection depth requirements for Class VI wells.

Following publication of the NODA and Request for Comment, EPA initiated a 45-day public comment period, which closed on October 15, 2009. EPA received 67 unique submittals from 64 commenters, many of whom commented on the proposed rule. The Agency also held a public hearing in Chicago, IL on September 17, 2009. Six people, representing the oil and gas industry, electric utilities, water associations, and academia attended the hearing. Two attendees submitted oral comments at the hearing. A transcript of the public hearing is in the rulemaking docket (EPA-HQ-OW-2008-0390-391).

## 2.3 Regulatory Alternatives Considered

EPA developed four RAs that address the unique technical and administrative considerations posed by the GS of $CO_2$. These four RAs are described in subsequent sections and in Exhibit 2.1.

### 2.3.1 Regulatory Alternative 1

Under this first alternative, GS wells would need to be sited, constructed, operated, maintained, monitored, and closed in a manner that protects USDWs. RA1 would apply the performance standard under 40 Code of Federal Regulations (CFR) 144.12(a) that prohibits fluid movement that endangers USDWs. For the purpose of this analysis, EPA assumed that operators would construct wells to inject below the lowermost USDW.

No specific "technology" standards would accompany the performance standard and each permitting authority would be left to interpret what technical standards or best management practices would be included in GS well permits based on the geology of the proposed site and the proposed injection activity. Permitting authorities are encouraged to issue permits for GS wells so that owners and operators would be subject to enforceable standards.

This alternative would offer flexibility to each permitting authority to interpret what would need to be included in GS well permits. While some stakeholders advocated a flexible approach for certain elements of a GS regulation, none advocated complete flexibility in the GS rule. If this alternative were adopted, EPA would need to develop numerous technical guidances to assist permitting authorities and to help injection well owners and operators understand and interpret the performance standards.

### 2.3.2 Regulatory Alternative 2

This RA is similar to the "basic" UIC Program regulatory standards for injection associated with oil and gas recovery, modified to address the potential impacts to USDWs from the injection of large volumes of potentially corrosive $CO_2$. The GS-specific components of this RA include the use of corrosion-resistant construction materials and surface atmospheric or soil gas monitoring. This RA also gives permitting authorities flexibility to interpret certain elements in their permit requirements. For the purpose of this analysis, EPA assumed that operators would construct wells to inject below the lowermost USDW.

*Geologic Site Characterization:* Under this RA, GS wells would need to be sited in an area with geological layers that are adequate for receiving proposed volumes of injected $CO_2$, confining it below USDWs, and providing long-term storage with no movement of any fluids that endangers a USDW. An adequate site would consist of: an injection zone of sufficient areal extent, thickness, porosity, and permeability; a containment mechanism that is free of major non-sealing faults; and a primary confining system of sufficient areal extent and integrity to allow injection at the proposed rates and volumes without initiating or propagating fractures. Similar configurations are typical of oil and gas wells which are typically located in areas where the natural geology confines oil and/or natural gas in permeable formations below a confining system.

Under this RA, owners or operators of a proposed GS injection well would demonstrate the presence and adequacy of the injection zone and confining system by providing geological data, including geological names and lithologic descriptions of the formations, and information on their thickness and depth. Owners or operators would also provide a map of the injection well and the applicable AoR and other information, such as maps, cross-sections, and a list of penetrations into the injection zone. Under this RA, owners or operators would also provide the geologic name and thickness of all USDWs that may be affected by the injection.

*AoR and Corrective Action:* Under this RA, owners and operators would define the AoR for the GS project based on a calculated radius or by modeling. The use of models is encouraged, but would not be required. Within the defined AoR, owners or operators would locate and identify all artificial penetrations (including active and abandoned wells and mines) that penetrate the confining system; provide a description of each well's type, construction, date drilled, location, and depth; determine, based on publicly available data, whether the abandoned wells have been plugged in a manner that prevents the movement of $CO_2$ or associated fluids; and employ corrective action at all wells that may endanger USDWs using appropriate methods approved by the Director.

*Injection Well Construction:* Under this RA, GS wells would be cased and cemented to prevent movement of fluids into or between USDWs. This mirrors the current Class II requirements; however this RA includes additional components to address the unique nature of $CO_2$ injected for GS. For example, RA2 would require that the casing and tubing for GS wells be adequate to withstand the corrosive nature of the injected $CO_2$ and any impurities at the anticipated operational conditions, and meet American Petroleum Institute (API) standards for casing, tubing, and packer. GS wells would also be constructed using corrosion-resistant cement in zones where contact between the cement and $CO_2$ is likely or where cement integrity is critical (e.g., through the primary confining system). Owners or operators would need to verify the integrity and location of the cement using the best available technologies for evaluating cement quality, identifying the location of channels or contaminated cement, and validating the casing-cement and cement-formation bonds through the primary confining system. Owners and operators will also be required to inject below the lowermost USDW, except in the limited number of cases where operators apply for and receive a permit for a waiver of this requirement. Waiver applications will demonstrate that USDWs above and below the injection zone will not be endangered as a result of $CO_2$ injection and will evaluate the following components: the integrity of the upper and lower confining units; the suitability of the injection zone; the potential capacity of the geologic formation to sequester $CO_2$; community needs, demands, and supply from drinking water sources; and any other applicable considerations or information requested by the director.

*Injection Well Operation:* Under this RA, $CO_2$ injection for GS should be conducted such that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs. Higher operating pressures may be allowed if approved by the permitting authority.

*MIT:* Under this RA, owners and operators of GS wells would demonstrate that their wells have internal MI (i.e., that there is no significant leak in the casing, tubing or packer) and external MI, (i.e., there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore).

Under this RA, owners and operators of GS wells would demonstrate internal MI by continuously monitoring injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long-string casing. This RA does not stipulate specific testing methods for external MITs; rather, flexibility is provided to owners and operators and permitting authorities to propose and approve methods that are appropriate to the specific project. A variety of testing methods are available and a flexible approach would allow owners and operators to adopt new testing technologies that are appropriate to $CO_2$ injection if they become available. Under this RA, MITs would be conducted at a frequency determined by the permitting authority.

*Monitoring:* Under this RA, GS well owners and operators would monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics, as determined by the permitting authority. Owners and operators would report annually on the characteristics of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, and on the results of MITs.

*Injection Well Plugging and Post-Injection Site Care (PISC):* When injection through a well is concluded, the injection well would be plugged in a way that ensures that it would not serve as a conduit for future fluid movement. Under this RA, owners and operators of GS wells would take appropriate actions, as approved by the permitting authority, to plug the injection well. Plugging activities may include ensuring that the well is in a state of static equilibrium with mud or equalized prior to placement of the plugs; plugging the well with cement in a manner that will not allow the movement of fluids either into or between USDWs; placing cement plugs; and tagging and testing each plug used for seal and stability. RA2 would also require owners and operators of GS wells to submit to the permitting authority a plan for conducting post-injection monitoring for ten years after injection wells are plugged to confirm that any post-injection $CO_2$ movement is limited to intended zones (it does not specify the methods by which accurate monitoring data may be collected, however). Once approved, owners and operators would then be required to implement the approved plan.

*Financial Responsibility:* Under this RA, owners and operators would demonstrate the resources necessary to plug the injection well.

### 2.3.3 Regulatory Alternative 3

For reasons discussed in Chapters 4 and 5 of this Cost Analysis, RA 3 has been selected as the final rule.

Many of the geologic data elements under this RA are similar to those required under the Class I non-hazardous regulations. This RA contains technical standards that mirror the stringent deep-well requirements for disposal of non-hazardous industrial wastes, with some additional requirements to account for the unique nature of $CO_2$ injection for GS. It is more stringent and prescriptive than RA2. The paragraphs below describe the specific elements of this alternative, highlighting the differences between RA2 and RA3.

*Site Characterization:* Under this RA, in addition to an adequate injection zone, containment mechanism, and primary confining system, an owner or operator of a proposed GS site may be required, at the Director's discretion, to characterize additional zones that could impede vertical fluid movement,

allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

This RA is more prescriptive than RA2 regarding the types and level of detail of the geological information that owners and operators would submit. The owner or operator of a proposed GS project site demonstrate the presence and adequacy of the injection and confining zones by providing information on the geologic structure, overburden and subsurface structures, and geochemical information about native and injected fluids.

To evaluate the potential for adverse effects associated with $CO_2$ injection, owners and operators also provide information on fractures in the confining zone and, if directed, any additional zones. Under RA3, owners and operators also eliminate sites with potential seismic risks. Additionally, under RA3, owners and operators characterize the overburden and subsurface structures, and provide data on subsurface porosity and permeability and geomechanical information, e.g., on fractures, stress, rock strength, and formation fluids.

Operators and operators also submit data on geochemistry within the injection zone and above the confining zone, including USDWs; this serves as baseline data to which results of future monitoring would be compared throughout the injection phase. Geochemical data could also serve as inputs for modeling to predict $CO_2$ movement.

*AoR and Corrective Action*: Under this RA, owners and operators of GS wells determine, in three dimensions, the extent of the AoR based on computational modeling that accounts for the physical and chemical properties of all phases of the injected $CO_2$ stream, $CO_2$ plume, and the associated pressure front. The models will be based on data collected at the site as part of the site characterization as well as anticipated operating data. Additionally, owners and operators identify all artificial penetrations (including active and abandoned wells and mines) in the AoR, determine based on publically available data which of these pose a risk to USDWs and therefore need corrective action, and apply corrective action using materials compatible with the carbon dioxide stream and other appropriate methods. At the Director's discretion, owners and operators have the option to phase-in corrective action and focus on those wells in the portion of the AoR that would be intersected by the $CO_2$ plume or pressure front over the early years of the injection operation.

This RA also requires all owners and operators to develop and submit an AoR and corrective action plan as a part of the permit application. The plan will describe how the owner or operator would determine the initial AoR, what corrective action will be performed up front and what will be phased in, and a plan for periodic reevaluation of the AoR (at least every 5 years) to incorporate monitoring and operational data to verify that the $CO_2$ is moving as predicted within the subsurface. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

*Injection Well Construction:* This RA prescribes that the well's surface casing be set through the base of the lowermost USDW (unless a waiver is granted to inject above the USDW) and be cemented to the surface. Under this RA, owners and operators will also be required to inject below the lowermost USDW, except in the limited number of cases where operators apply for and receive a permit for a waiver of this requirement. Waiver applications will demonstrate that USDWs above and below the

injection zone will not be endangered as a result of $CO_2$ injection and will evaluate the following components: the integrity of the upper and lower confining units; the suitability of the injection zone; the potential capacity of the geologic formation to sequester $CO_2$; community needs, demands, and supply from drinking water sources; and any other applicable considerations or information requested by the director.

Under RA3, the long string casing and cement would extend to the injection zone and be cemented to the surface. A packer will be required and be set opposite a cemented interval of the long string casing, at a depth approved by the Director. As with RA2, the well will be constructed with materials that meet or exceed standards developed by API or American Society for Testing and Materials (ASTM) International and can withstand the corrosive nature of the injected $CO_2$ and any impurities throughout the life of the project. Cements would be required to be compatible with the $CO_2$, and the adequacy of the cement would be verified using the best available technologies. During drilling and construction, the owner or operator run logs, surveys, and tests to determine or verify the properties of subsurface formations to assure conformance with the construction requirements.

*Injection Well Operation:* Under this RA, the $CO_2$ injection pressure will not be permitted to exceed 90 percent of the fracture pressure of the injection zone, and injection would not be allowed to initiate new fractures, propagate existing fractures, or cause fluid movement into USDWs.

The owner or operator will be required to equip the well with alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit. UIC Permits for Class VI wells will be issued for the operating life of the facility and the PISC period. The Director will review each issued Class VI well UIC permit at least once every 5 years to determine whether it should be modified, revoked and reissued, terminated or modified.

*MIT:* As with RA2, owners and operators of GS wells will need to demonstrate that their wells have internal and external MI. It differs from RA2 in that it specifies the tests that may be used to demonstrate external MI, e.g., a tracer survey, temperature or noise logs, a casing inspection log, or another suitable method required and/or approved by the Director. Additionally, under this RA, MITs will be conducted at least once every year.

*Monitoring:* Like RA2, this RA requires owners and operators to monitor their injectate. However, this RA also requires owners and operators to continuously monitor injection pressure, rates, and volumes, as well as the pressure on the annulus. Owners and operators also monitor the well materials for signs of corrosion. Operators would submit semi-annual operating reports, and would submit MIT and other test results within 24 hours if they indicate a problem with operations.

Under this RA3, owners and operators of GS wells develop and implement a plan to perform testing and monitoring to protect USDWs by tracking the position of the $CO_2$ plume and pressure front; monitoring for geochemical changes in subsurface formations; and if directed, monitoring at the surface for evidence that $CO_2$ may have leaked to USDWs.

Owners and operators conduct a pressure fall-off test at least once every five years. The owner or operator also track the subsurface extent of the $CO_2$ plume and pressure front by monitoring pressure changes above the confining zone, or using geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or other down-hole $CO_2$ detection tools).

This RA also requires owners and operators to monitor ground water quality and geochemical changes above the confining zone using a network of monitoring wells and track changes relative to baseline geochemical data.

Finally, under this RA, owners and operators report twice per year, rather than annually, on all required monitoring.

*Injection Well Plugging and PISC:* Under this RA, owners and operators submit, gain approval for, and implement a well plugging plan. To plug injection wells owners and operators: flush the well with a buffer fluid, perform an MI test, and plug the well in a manner that will prevent the movement of fluid that may endanger USDWs.

Under this RA, owners and operators develop and implement a plan for PISC and site closure and submit the plan as part of the permit application. For at least 50 years (unless the Director approves a shorter time frame based on data submitted as part of the permit application, or collected during PISC), owners and operators monitor the site to show the position of the $CO_2$ plume and pressure front and to demonstrate that USDWs are not being endangered. After 50 years, owners and operators perform a non-endangerment demonstration that the $CO_2$ plume and pressure front have stabilized and that no additional monitoring is needed to assure that the project does not pose an endangerment to USDWs. At this point, the Director will determine whether further monitoring is necessary or authorize closure of the site.

*Financial Responsibility:* Under RA3, owners and operators demonstrate and maintain financial responsibility and resources for plugging the injection well, corrective action, remediation, providing post-injection site monitoring and closure (accounting for inflation) and emergency and remedial response. The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit. The Director is charged with approving financial instruments submitted by owners and operators that he or she deems sufficient to address endangerment to USDWs. Acceptable financial instruments include: trust funds, surety bonds, letters of credit, escrow accounts and insurance. The owner or operator must maintain such financial responsibility and resources until (1) The Director receives and approves the completed PISC and site closure plan; and (2) The Director determines that the site has reached the end of the post injection site care period.

*Emergency and Remedial Response:* Under RA3, owners and operators develop, implement and periodically update a plan that describes actions to be taken to address events that may cause endangerment to USDWs during the construction, operation and PISC periods of a GS project. If there is evidence of potential endangerment of USDWs, the owner or operator would be required to cease injection, investigate and identify the release, notify the Director within 24 hours, and implement the emergency and remedial response plan.

### 2.3.4 Regulatory Alternative 4

This RA prescribes specific technologies that GS well owners and operators would use for geologic studies, models, and well materials to protect USDWs from the injection of large volumes of $CO_2$. This alternative is the most prescriptive; it provides the most regulatory certainty and consistency (and therefore the least flexibility). Many components of this RA equal or exceed the activities performed by owners and operators of Class I hazardous waste injection wells and it includes additional elements beyond the other RAs. The following sections describe this RA, highlighting the differences from RA3.

*Site Characterization:* Under this RA, all GS sites would need to have, in addition to the injection zone, containment mechanism, and confining system, additional zones that will impede vertical fluid movement, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation. This differs from RA3 in that every GS site would need to have these additional layers. It is equivalent to the current requirements for Class I hazardous waste injection wells, and differs from RA3 in that it applies to all GS projects.

Under this RA, owners and operators would provide more detailed data about the injection zone and confining zones than under the other alternatives. In addition to the data that owners and operators would submit under RA3, they would also need to submit geological core data, outcrop data, 3-dimensional seismic survey data, and well logs. In areas with insufficient data, owners and operators would be encouraged to drill at least one stratigraphic test well to describe the specific petrophysical parameters of the injection zone and the primary confining system and additional confining and containment zones. Under this RA, the baseline geochemical data would include more detailed information, e.g., on water-rock-$CO_2$ geochemistry and mineral reactions.

*AoR and Corrective Action:* As with RA3, owners and operators would be required to develop and implement an AoR and corrective action plan describing the process by which they would define the AoR, apply corrective action, and periodically reevaluate the AoR. As with RA3, owners and operators would define the AoR using computational models of the injected $CO_2$ stream, $CO_2$ plume and the associated pressure front that are based on information collected as part of the site characterization as well as anticipated operating data. This RA would also specify that the models predict the $CO_2$ plume movement over 10,000 years.

As with RA3, owners and operators would determine which wells in the AoR require corrective action based on recent, reliable plugging records and remediate any wells that may endanger USDWs. This RA would also specify that wells needing corrective action be remediated using materials compatible with the carbon dioxide stream or other appropriate corrective action methods. As in RA3, owners and operators would, at the Director's discretion, have the option to phase in corrective action. This RA would specify that the AoR reevaluation be performed at least once every 5 years.

*Injection Well Construction:* As with RA3, this RA would specify the use of well materials and technologies (e.g., for casing, tubing, and cements) that employ the corrosion-resistant technologies. However, several elements of this RA are more prescriptive. For example, this RA would require the use of specialized, corrosion-resistant materials such as latex cement, metal alloys, and specialized tubing.

RA4 also specifies that the surface casing be set 100 feet below the lowermost USDW and that the packer be set no more than 100 feet above the uppermost perforation. Owners and operators would have to construct injection wells to inject below the lowermost USDW, and at a sufficient depth so the $CO_2$ would remain in a supercritical state (to potentially avoid MI concerns associated with $CO_2$ phase changes). As with RA3, during drilling and construction, the owner or operator would run logs, surveys, and tests to determine or verify the properties of subsurface formations to assure conformance with the construction requirements.

*Injection Well Operation:* Under this RA, injection should be conducted such that pressure in the injection zone does not exceed 90 percent of the fracture pressure in any portion of the area defined by the anticipated pressure front, or the capillary entry pressure at any point in the lower-most portion of the primary confinement system. As with RAs 2 and 3, injection may not initiate new fractures, propagate existing fractures, or cause fluid movement into USDWs.

RA4 contains one additional element that is specific to injection of $CO_2$ for GS. Owners and operators would, at the Director's discretion, be required to add an odorant or a tracer to the injected $CO_2$ to facilitate early detection of leaks or movement outside of the intended injection zone to protect USDWs.

*MIT:* As with RA3, owners and operators of GS wells would demonstrate that their wells have internal and external MI. The sole difference is that this RA would require that the testing be conducted at least twice annually.

*Monitoring:* Some of the monitoring elements of this RA parallel those in RA3 (i.e., owners or operators would conduct baseline geochemical monitoring and develop and implement plans for monitoring geochemical changes in the subsurface, monitoring their injectate, tracking the $CO_2$ plume and pressure front, and conducting surface atmospheric or soil gas $CO_2$ monitoring). This RA also requires that a pressure fall-off test be conducted annually.

This RA differs from RA3 in that it would prescribe the use of certain sophisticated technologies, which exceed the detail prescribed in the existing regulations. For example, it specifies that the network of monitoring wells used for geochemical monitoring should be constructed, using best available technologies, of corrosion-resistant materials that could withstand extended contact with the $CO_2$ to provide some assurance that monitoring wells in the AoR do not potentially become conduits for movement of fluids out of the injection zone.

Under this RA, surface atmospheric or soil gas monitoring would be expanded to include monitoring at all artificial penetrations and at other sensitive areas (e.g., in buildings and man-made surface structures that are intended for human occupancy) within the AoR.

In addition, under this RA, operators or operators would report monthly on the characteristics of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, and on the results of MITs, and ground water and atmospheric/soil gas monitoring.

*Injection Well Plugging and PISC:* Under this RA, owners and operators would develop and implement well plugging and PISC and site closure plans specified under RA3. Plugging activities

would be similar to those required under RA3. This RA differs from RA3 in that the post-injection monitoring period would be over a period of 100 years (also followed by a non-endangerment demonstration).

*Financial Responsibility:* The financial responsibility requirements under this RA are the same as under RA3, i.e., the owners and operators would demonstrate financial responsibility for plugging the well, corrective action, remediation, providing post-injection monitoring, and emergency and remedial response, accounting for inflation.

*Emergency and Remedial Response:* The requirements for developing and implementing an emergency and remedial response plan to address movement of injection or formation fluids that may endanger USDWs under RA4 are the same as those that would be required under RA3.

### 2.3.5 Comparative Summary of Regulatory Alternatives

Exhibit 2.1 below summarizes the components of each RA of the GS rule.

## Exhibit 2.1 Comparison of Alternatives for GS of $CO_2$

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| **Site Characterization** | | | |
| GS wells must be sited in a manner that protects USDWs from endangerment. | A geologic system comprised of:<br>• A receiving zone of sufficient areal extent, thickness, porosity, and permeability;<br>• A containment mechanism that is free of transmissive faults or fractures; and<br>• A confining zone of sufficient areal extent and integrity to contain all injected fluid to allow injection at proposed rates and volumes without initiating or propagating fractures in the confining zone. | A geologic system comprised of:<br>• An injection zone of sufficient areal extent, thickness, porosity, and permeability;<br>• A containment mechanism that is free of transmissive faults or fractures;<br>• A confining zone of sufficient areal extent and integrity to contain all injected fluid to allow injection at proposed rates and volumes without initiating or propagating fractures in the confining zone; and<br>• At the Director's discretion, additional zones that will impede vertical fluid movement, allow for pressure dissipation, are free of faults and fractures, and provide additional opportunities for monitoring, mitigation, and remediation. | A geologic system comprised of:<br>• A injection zone of sufficient depth, areal extent, thickness, porosity, and permeability;<br>• A containment mechanism that is free of transmissive faults or fractures;<br>• A primary confining system of sufficient areal extent and integrity to contain all injected fluid to allow injection at proposed rates and volumes without initiating or propagating fractures in the confining zone; and<br>• Additional zones that will impede vertical fluid movement, allow for pressure dissipation, are free of faults and fractures, and provide additional opportunities for monitoring, mitigation, and remediation. |
| | Provide geological data on the injection zone and confining zone, including:<br>• Lithologic description.<br>• Geological name.<br>• Thickness and depth. | Provide information on the geologic structure of the proposed site, including:<br>• Maps and cross sections of local geologic structure;<br>• Identification of faults and fractures in the confining zone and determination that they would not interfere with containment;<br>• At the Director's discretion, identification of faults and fractures in additional zones and determination that they would not interfere with containment;<br>• Eliminate sites with potential seismic risks. | Provide information on the geologic structure of the proposed site, including:<br>• Maps and cross sections of local geologic structure.<br>• Identification of faults and fractures in the primary confining system and determination that they would not interfere with containment.<br>• Identification of faults and fractures in additional zones and determination that they would not interfere with containment.<br>• Information on seismic history and the presence/depth of seismic sources. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | Provide a map of the injection well and the applicable AoR. | Characterize the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations based on:<br>• Data on the areal extent, thickness, capacity, porosity, and permeability of the receiving formations, the confining zones and, at the Director's discretion, any additional zones.<br>• Geomechanical information on fractures, stress, rock strength, and in situ fluid pressures within the confining zones.<br>• Geologic and topographic maps and cross sections illustrating regional geology. | Characterize the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations based on:<br>• Data on the areal extent, thickness, capacity, porosity, and permeability of the receiving formations, the primary confining system, and additional confining and containment zones, including any geology/facies changes, based on geologic cores, outcrop data, 3-dimensional seismic surveys, and well logs.<br>• In areas with insufficient data, the drilling of at least one stratigraphic test well in the area is encouraged to determine site specific petrophysical parameters of the injection and confining formations.<br>• Geomechanical information on fractures, stress, rock strength, and in situ fluid pressures within the primary confining system and additional confining and containment zones.<br>• Geologic and topographic maps and cross sections illustrating regional geology. |
| | Provide the geologic name and depth to bottom of all USDWs that may be affected by the injection. | Provide geochemical information on subsurface aquifers, including all USDWs:<br>• Baseline geochemistry.<br>• Maps and cross sections of USDWs. | Provide geochemical information on subsurface aquifers, including all USDWs:<br>• Baseline geochemical data on water-rock-$CO_2$ geochemistry and mineral reactions.<br>• Maps and cross sections of USDWs. |
| | | Conduct baseline geochemical monitoring within the injection system and above the confining system before injection commences. | Conduct baseline geochemical monitoring within the injection system and above the confining systems before injection commences. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | Provide information on the AoR:<br>• Maps and cross sections of the AoR.<br>• List of penetrations into the injection zone. | Provide information on the AoR:<br>• Maps and cross sections of the AoR.<br>• List and maps of all penetrations into the injection zone and confining zones, and at the Director's discretion, into any additional zones, including structures that are intended for human occupancy using publicly available data..<br>• List and associated data (well type and construction, date drilled, location, depth, plugging record, and any other information required by the Director) for all wells into the confining zones. | Provide information on the AoR:<br>• Maps and cross sections of the AoR.<br>• List and maps of penetrations into the injection zone and additional confining and containment zones including structures that are intended for human occupancy using publicly available data.<br>• List and associated data (well type and construction, date drilled, location, depth, plugging record, and any other information required by the Director) for all wells into the injection zone, discretionary confining and containment zones. |
| | Provide information on proposed:<br>• Testing and Monitoring Plan<br>• Injection well plugging plan<br>• PISC and site closure plan<br>• Emergency and remedial plan; and<br>Any other information requested by the Director | Provide information on proposed:<br>• Operating data<br>• Formation testing program<br>• Stimulation program<br>• Injection procedure<br>• Surface and subsurface well construction (including schematic)<br>• Contingency plan to address well shut-ins and failures<br>• Testing and Monitoring Plan<br>• Injection well construction procedures<br>• Federal Register (FR) responsibility demonstration<br>• Injection well plugging plan<br>• PISC and site closure plan<br>• Emergency and remedial plan; and<br>• Any other information requested by the Director | Provide information on proposed:<br>• Operating data<br>• Formation testing program<br>• Stimulation program<br>• Injection procedure<br>• Surface and subsurface well construction (including schematic)<br>• Contingency plan to address well shut-ins and failures<br>• Testing and Monitoring Plan<br>• Injection well construction procedures<br>• FR responsibility demonstration<br>• Injection well plugging plan<br>• PISC and site closure plan<br>• Emergency and remedial plan; and<br>Any other information requested by the Director |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | | Provide, in operating permit application:<br>• All available logging and testing data<br>• MI demonstration<br>• Anticipated max. injection pressure<br>• Formation testing results<br>• Injection procedure<br>• Information on the compatibility of $CO_2$ stream with formation fluids and minerals in the injection and confining zones and with proposed well construction materials<br>• Modeled AoR<br>• Status of corrective action on wells in the AoR; and,<br>Any other information required by the Director. | Provide, in operating permit application:<br>• All available logging and testing data<br>• MI demonstration<br>• Anticipated max. injection pressure<br>• Formation testing results<br>• Injection procedure<br>• Information on the compatibility of $CO_2$ stream with formation fluids and minerals in the injection and confining zones and with proposed well construction materials<br>• Modeled AoR<br>• Status of corrective action on wells in the AoR; and,<br>• Any other information required by the Director. |
| **AoR Study and Corrective Action** | | | |
| | The AoR may be determined by a calculating a fixed radius or by modeling. | The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected $CO_2$ stream, $CO_2$ plume, and pressure front for an appropriate timeframe to ensure there is no longer a threat to USDWs based on proposed injection rates and volumes. Models must be based on site specific information, geologic information collected to characterize the injection zone, confining zones, and additional zones, as well as anticipated operating data. | The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected $CO_2$ stream, $CO_2$ plume, and pressure front for 10,000 years based on proposed injection rates and volumes. Models must be based on site specific information, geologic information collected to characterize the injection zone, confining zones, and additional zones, as well as anticipated operating data. |
| | | As a part of the permit application, the owner/operator develops and submits an AoR and corrective action plan for Director approval that:<br>• Requires the reevaluation of the AoR at a minimum fixed frequency not to exceed five years; and;<br>• Describes how and when (prior to/outside of the minimum fixed frequency) the AoR will be reevaluated taking into account: changes in site operation; when monitoring data differs from modeling results; and, considerations for maintaining site access; and<br>• Corresponds with the $CO_2$ plume and pressure front *and* indicates whether corrective action will performed up-front or on a phased-in basis; how corrective action will be adjusted if the AoR changes; and how site access will be guaranteed for future corrective action. | As a part of the permit application, the owner/operator develops and submits an AoR and corrective action plan for Director approval that:<br>• Requires the reevaluation of the AoR at a minimum of every five years;<br>• Describes how and when the AoR will be reevaluated taking into account: changes in site operation; when monitoring data differs from modeling results; and, considerations for maintaining site access; and<br>• Corresponds with the $CO_2$ plume and pressure front *and* indicates whether corrective action will performed up-front or on a phased-in basis; how corrective action will be adjusted if the AoR changes; and how site access will be guaranteed for future corrective action. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | Identify all artificial penetrations (including active and abandoned wells and mines) in the AoR that penetrate the confining zone. Provide: a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. | Identify all artificial penetrations (including active and abandoned wells and mines) in the AoR that penetrate the confining t zones (and at the Director's discretion any additional zones) and pose an endangerment to USDWs. Provide: a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. | Identify all artificial penetrations (including active and abandoned wells and mines) in the AoR that penetrate the primary confining system and additional confining and containment zones, and pose an endangerment to USDWs. Provide: a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. |
| | Determine if they have been plugged in a manner that prevents the movement of $CO_2$ or associated fluids, and identify those that need corrective action. | Determine if they have been plugged in a manner that prevents the movement of $CO_2$ or associated fluids based on reliable, recent plugging records, and identify those that need corrective action. | Determine if they have been plugged in a manner that prevents the movement of $CO_2$ or associated fluids based on reliable, recent plugging records, and identify those that need corrective action. |
| | Conduct corrective action for the entire AoR prior to injection, remediating those wells in the AoR that pose a risk to USDWs using appropriate corrective action methods determined by the permitting authority | Corrective action will be conducted up-front or on a phased-in basis as per the AoR and corrective action plan (and if approved by the director). This includes, remediating those wells in the AoR that pose a risk to USDWs using materials compatible with the $CO_2$ stream and other appropriate corrective action methods. | Corrective action will be conducted up-front or on a phased-in basis as per the AoR and corrective action plan (and if approved by the director). This includes, remediating those wells in the AoR that pose a risk to USDWs using materials compatible with the $CO_2$ stream and other appropriate corrective action methods. |
| **Injection Well Construction** | | | |
| GS wells must be constructed in a manner that protects USDWs from endangerment. | The well must be cased and cemented to prevent movement of fluids into or between USDWs. | Provide to the Director for approval of casing and cementing program:<br>Depth to injection zone; injection, external, internal pressure and axial loading; hole size; size and grade of casing strings; information about $CO_2$ stream (corrosiveness, quantity, composition, temperature) and formation fluids; down-hole temperatures; lithology of injection and confining zones; type/grade of cement; and cement additives;<br>And, for approval of tubing and packer use: (in addition to information above)<br>Depth of setting; annular pressure; injection rate; casing size; and tubing tensile, burst, and collapse strengths. | Provide to the Director for approval of casing and cementing program:<br>Depth to injection zone; injection, external, internal pressure and axial loading; hole size; size and grade of casing strings; information about $CO_2$ stream (corrosiveness, quantity, composition, temperature) and formation fluids; down-hole temperatures; lithology of injection and confining zones; type/grade of cement. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| Injection must be below the lowermost USDW, except in the limited number of cases in which a waiver application is approved. (See RA3 for waiver application requirements.) | Injection must be below the lowermost USDW, except in the limited number of cases in which a waiver application is approved. (See RA3 for waiver application requirements.) | Surface casing should be set through the base of the lowermost USDW and cemented to the surface through the use of a single or multiple strings of casing and cement. Injection must be below the lowermost USDW, except in the limited number of cases in which a waiver application is approved.<br><br>Owners/operators seeking a waiver to inject below the lowermost USDW must submit to the Director a supplemental report that demonstrates USDWs will not be endangered as a result of $CO_2$ injection. Before being granted a waiver, owners/operators would have to evaluate the following components as they relate to their GS projects:<br>• the integrity of the upper and lower confining units;<br>• the suitability of the injection zone;<br>• the potential capacity of the geologic formation to sequester $CO_2$;<br>• community needs, demands, and supply from drinking water sources; and<br>• any other applicable considerations or information requested by the Director.<br>The director will give public notice that a waiver application has been submitted. The supplemental report must include the following:<br>• Injection zone is laterally continuous, not hydraulically connected to USDWs; does not outcrop; and has adequate injectivity, volume, and sufficient porosity to safely contain the injected CO2 and formation fluids, and has appropriate geochemistry.<br>• Injection zone is adequate to prevent fluid movement and pressure buildup outside of the injection zone; and, that the confining units are free of transmissive faults and fractures.<br>• Using computational modeling, show that USDWs above and below the injection zone will not be endangered as a result of fluid movement.<br>• Well design and construction, in conjunction with the waiver, will ensure isolation of the injectate.<br>• Monitoring and testing and any additional plans will be tailored to the GS project to ensure protection of USDWs above and below the injection zone. | Surface casing drilled below the USDW shall be set 100 feet below the lowest USDW and cemented to the surface.<br><br>Injection must be below the lowermost USDW and the $CO_2$ must remain in a supercritical state to avoid MI concerns associated with phase change. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | The integrity and location of the cement must be verified using technology capable of radially evaluating cement quality, identifying the location of channels or contaminated cement, and validating the casing-cement and cement-formation bonds through primary confining system. | At least one long-string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The integrity and location of the cement must be verified using the best available technology capable of radially evaluating cement quality and identifying the location of channels to ensure that USDWs are not endangered. | At least one long-string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The integrity and location of the cement must be verified using the best available technology capable of radially evaluating cement quality and identifying the location of channels to ensure that USDWs are not endangered. |
| | Casing, tubing, and packer should be adequate to withstand the corrosive nature of the injected $CO_2$ and any impurities at the anticipated pressure, temperature and other operational conditions and meet API standards. | Casing, tubing, and packer should be adequate to withstand the corrosive nature of the injected $CO_2$ and any impurities at the anticipated pressure, temperature and other operational conditions and meet API standards. | Use specialized, corrosion-resistant materials such as metal alloy casing and specialized tubing that can withstand the corrosive nature of the injected $CO_2$ and any impurities at the anticipated pressure, temperature and other operational conditions and must meet API standards using best available technologies. |
| | | Inject through tubing and packer that is set at a depth opposite a cemented interval of the long-string casing at a depth approved of by the Director. | Inject through tubing and packer that is set at a depth opposite a cemented interval of the long-string casing and set no more than 100 feet above the uppermost perforation or open hole for the $CO_2$ storage reservoir. |
| | Use corrosion resistant cements in zones where cement-$CO_2$ contact is likely or cement integrity is critical (e.g. cement zones through primary confining system). | Use corrosion-resistant cement (e.g., phosphate-based non-Portland cements), that can withstand extended contact with injected $CO_2$ and associated impurities throughout the life of the project. | Use specialized corrosion-resistant latex cement that can withstand extended contact with injected $CO_2$ and associated impurities throughout the life of the project. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| **Logging, Sampling, and Testing Prior to Injection Well Operation** | | | |
| GS wells must be operated in manner that protects USDWs from endangerment. | | Submit to the Director:<br>• A schedule of all logging, sampling, and testing activities to be completed 30 days prior to conducting first test and notification of any changes 30 days prior to next test.<br>• A report prepared by a knowledgeable log analyst that includes an interpretation of all logs and tests conducted to determine or verify depth, thickness, porosity, permeability, and lithology of, and formation fluid salinity of, all relevant geologic formations.<br>Logs and tests must include:<br>• Deviation checks<br>• Other logs as required by Director at various intervals, including:<br>*Before* surface casing installation: resistivity, sp, and caliper logs; and<br>*After* casing is set and cemented: cement bond and variable density log to evaluate cement quality radially;<br><br>*Before* long-string casing installation: resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder, and any other logs required by Director; and<br>*After* long-string casing is set and cemented: cement bond and variable density log, and a temperature log; and<br><br>A series of MIT logs which may include pressure test, tracer survey, temperature or noise log, casing inspection log and any other tests required by Director. | Submit to the Director:<br>• A schedule of all logging, sampling, and testing activities to be completed 30 days prior to conducting first test and notification of any changes 30 days prior to next test.<br>• A report prepared by a knowledgeable log analyst that includes an interpretation of all logs and tests conducted to determine or verify depth, thickness, porosity, permeability, and lithology of, and formation fluid salinity of, all relevant geologic formations.<br>Logs and tests must include:<br>• Deviation checks<br>• Other logs as required by Director at various intervals, including:<br>*Before* surface casing installation: resistivity, sp, and caliper logs; and<br>*After* casing is set and cemented: cement bond and variable density log;<br><br>*Before* long-string casing installation: resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder, and any other logs required by Director; and<br>*After* long-string casing is set and cemented: cement bond and variable density log, and a temperature log; and<br><br>A series of MIT logs which may include pressure test, tracer survey, temperature or noise log, casing inspection log if required by Director and any other tests required by Director. |
| | | Take whole cores and sidewall cores in the injection zone and confining systems and formation fluid samples from the injection zone(s) and submit to the director a detailed report and well log information about the cores and formation fluid samples, prepared by a log analyst; and any other or comparable information required and approved of by Director. | Take and submit to Director, whole cores and sidewall cores in the injection zone and confining systems and formation fluid samples of the injection zone; and any other or comparable information required and approved of by Director. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | | Record fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s). | Record fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone. |
| | | Determine or calculate injection and confining zone fracture pressure; physical and chemical characteristics of the injection zone, confining zone, and injection zone formation fluids. | Determine or calculate injection and confining zone fracture pressure; physical and chemical characteristics of the injection zone, confining zone, and injection zone formation fluids. |
| | | Perform a pump test or injectivity test prior to operation to verify hydrogeologic characteristics of the injection zone. | Perform a pump test or injectivity test prior to operation to verify hydrogeologic characteristics of the injection zone. |
| **Injection Well Operation** | | | |
| GS wells must be operated in a manner that protects USDWs from endangerment. | Injection should be conducted such that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs.<br>Higher operating pressures may be allowed if approved by the permitting authority. | Injection should be conducted such that pressure in the injection zone does not exceed 90 percent of the fracture pressure of the injection zone in any portion of the area defined by the anticipated pressure front. Injection may not initiate new fractures, propagate existing fractures in the injection zone, or cause fluid movement into USDWs; and, annulus pressure should exceed operating injection pressure unless otherwise specified by the Director. | Injection should be conducted such that pressure in the injection zone does not exceed 90 percent of the fracture pressure of the injection zone in any portion of the area defined by the anticipated pressure front, or the capillary entry pressure at any point in the lower most portion of the primary confining system. Injection may not initiate new fractures, propagate existing fractures, or cause fluid movement into USDWs; and, annulus pressure should exceed operating injection pressure unless otherwise specified by the Director. |
| | | Owners and operators are be required to equip the well with alarms and down-hole shut-off systems or other safety devices (e.g., check valves) approved by the Director, designed to alert the owner or operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit. | Equip with down-hole safety shutoff valves that engage when any operating parameters diverge beyond permitted ranges or a drop in annulus pressure is detected. |
| | | | At the director's discretion, add an odorant or a tracer to the injected $CO_2$ to facilitate early detection of leaks or movement outside of the intended injection zone in order to prevent endangerment of USDWs. |
| | | If a shutdown (i.e. down-hole or at the surface) is triggered, cease injection; investigate and identify cause of shutdown; determine if $CO_2$ has leaked into unintended zones; notify Director; restore and demonstrate MI to Director; notify Director when injection will resume. | If a down-hole shutdown is triggered, cease injection; investigate and identify cause of shutdown; determine if $CO_2$ has leaked into unintended zones; notify Director; restore and demonstrate MI to Director; notify Director when injection will resume. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| **MIT** | | | |
| GS wells must be monitored in a manner that protects USDWs from endangerment. | Demonstrate internal MI by monitoring injection pressure, flow rate, injected volumes, and pressure on the annulus as specified by the permitting authority. | Demonstrate internal MI by continuously monitoring injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long-string casing. | Demonstrate internal MI by continuously monitoring injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long-string casing. |
| | Demonstrate external MI, i.e., there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore at a frequency specified by the permitting authority. | Demonstrate external MI, i.e., there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore using a tracer survey of the bottom-hole cement (using a $CO_2$ -soluble tracer or a suitable alternative method (e.g., Oxygen Activation Log (OAL)), a temperature or noise logs or other tests suitable to wells injecting liquid/super critical $CO_2$ fluids as approved by the permitting authority), or if required by the director a casing inspection log; or, another suitable method required and/or approved by the Director at least once per year**.** | Demonstrate external MI, i.e., there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore using a tracer survey of the bottom-hole cement (using a $CO_2$ -soluble tracer or a suitable alternative method (e.g., OAL), a temperature or noise logs or other tests suitable to wells injecting liquid/super critical $CO_2$ fluids as approved by the permitting authority), or if required by the director a casing inspection log; or, another suitable method required and/or approved by the Director at least twice per year. |
| | | Report within 30 days (or with the next reporting period, whichever is later) the results of periodic MI tests, other tests required by the Director, or well workovers. | Report within 30 days (or with the next reporting period, whichever is later) the results of periodic MI tests, other tests required by the Director, or well workovers. |
| **Monitoring** | | | |
| | | As a part of the permit application, develop and submit a testing and monitoring plan for Director approval. | As a part of the permit application, develop and submit a testing and monitoring plan for Director approval. |
| GS wells must be monitored in a manner that protects USDWs from endangerment. | Monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics. | Monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics. | Monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics and to demonstrate their compatibility with the well materials. |
| | | Monitor injection wells for loss of mass, thickness, cracking, pitting and other signs of corrosion on a quarterly basis to ensure that the well components maintain integrity using coupons, routing $CO_2$ through a loop in the well, or an alternative method approved by the Director. | Monitor injection wells for loss of mass, thickness, cracking, pitting and other signs of corrosion on a quarterly basis to ensure that the well components maintain integrity using coupons, routing $CO_2$ through a loop in the well, or an alternative method approved by the Director. |
| | | Conduct a pressure fall-off test at least once every 5 years. | Conduct a pressure fall-off test at least once per year. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | | Track the subsurface extent of the $CO_2$ plume and pressure front using pressure and temperature gauges, resistivity logs, and other monitoring tools or using geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys) and/or other down-hole $CO_2$ detection tools or other methods as determined by the director. | Track the subsurface extent of the $CO_2$ plume and pressure front using pressure and temperature gauges, resistivity logs, and other monitoring tools and using geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys) and other down-hole $CO_2$ detection tools as determined by the director. |
| | | Monitor geochemical changes above the confining zone (and at the Director's discretion any additional zones). The number of monitoring wells should be based on site-specific information and may be a function of $CO_2$ injection rate and volume, geology, the presence of artificial penetrations, or other factors. | Monitor geochemical changes above the confining zone and additional confining and containment zones using best available technologies. Develop a monitoring well strategy; the number of monitoring wells should be based on site-specific information and may be a function of $CO_2$ injection rate and volume, geology, the presence of artificial penetrations, or other factors; wells should be constructed of corrosion-resistant materials. |
| | | At the Director's discretion and as part of the permit application, develop and implement a plan for surface air monitoring and/or soil gas monitoring to detect leakage of $CO_2$ in the AoR to ensure that $CO_2$ and any other contaminants moving with the $CO_2$ have not migrated through USDWs. | Develop and implement a plan for surface air monitoring and/or soil gas monitoring to detect leakage of $CO_2$ in the AoR, at all artificial penetrations within the AoR, and at other sensitive areas, e.g., in buildings and man-made surface structures that are intended for human occupancy to ensure that $CO_2$ and any other contaminants moving with the $CO_2$ have not migrated through USDWs. |
| | Report annually on the characteristics of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, and on the results of MITs. | Report twice per year on the characteristics of injection fluids and any changes from proposed operating data; injection pressure, flow rate, temperature, volume and annular pressure; a description of events that exceed operating parameters for annulus or injection pressures and any events that trigger a shutdown and response taken; monthly volume of $CO_2$ stream injected; and results of all monitoring. Report on MIT results within 30 days of testing, except in the cases where MIT or other test indicates a problem with the operations, which would be reported within 24 hours. Reports must be submitted to an electronic EPA system. Records on operational data are kept for 10 years after collection and certain other data are kept until 10 years after site closure. | Report monthly on the characteristics of injection fluids and any changes from proposed operating data; injection pressure, flow rate, temperature, volume and annular pressure; a description of events that exceed operating parameters for annulus or injection pressures and any events that trigger a shutdown and response taken; monthly volume of $CO_2$ stream injected; and results of all monitoring. Report on MIT results within 30 days of testing, except in the cases where MIT or other test indicates a problem with the operations, which would be reported within 24 hours. Reports must be submitted to an electronic EPA system. Records on operational data are kept for 10 years after collection and certain other data are kept until 10 years after site closure. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| **Well Plugging, PISC and Site Closure** | | | |
| | As a part of the permit application, develop and submit a well plugging plan for Director approval. | As a part of the permit application, develop and submit a well plugging plan for Director approval which includes: appropriate test methods to determine bottom-hole reservoir pressure and MIT to be used; type and number of plugs; location/placement of each plug; type of $CO_2$ compatible material to be used in plugging; and the method of plug placement. | As a part of the permit application, develop and submit a well plugging plan for Director approval which includes: appropriate test methods to determine bottom-hole reservoir pressure and MIT to be used; type and number of plugs; location/placement of each plug; type of $CO_2$ compatible material to be used in plugging; and the method of plug placement. |
| GS wells must be closed in a manner that protects USDWs from endangerment. | Ensure that the well is in a state of static equilibrium with mud equalized prior to placement of the plugs (or as required by the permitting authority). | Flush the well with a buffer fluid and determine bottom-hole reservoir pressure prior to well plugging. | Flush the well with a buffer fluid and determine bottom-hole reservoir pressure prior to well plugging. |
| | | Perform an MIT prior to plugging the well to ensure the integrity of that portion of the long-string casing and cement that will be left in the ground after plugging. | Perform an MIT prior to plugging the well to ensure the integrity of that portion of the long-string casing and cement that will be left in the ground after plugging. |
| | Plug the well with cement in a manner that will not allow the movement of fluids either into or between USDWs (or as required by the permitting authority), placing the cement plugs in a manner specified by the Director. | Notify the Director at least 60 days before plugging the well, submitting any revisions to the well plugging plan for Director approval; and, plug the injection well per the approved well plugging plan. | Notify the Director at least 60 days before plugging the well, submitting any revisions to the well plugging plan for Director approval; and, plug the injection well per the approved well plugging plan. |
| | | Within 60 days after plugging or at the time of the next quarterly report (whichever is less), owner/operator must submit a certified plugging report to the Director. The owner or operator shall retain the well plugging report for ten years following site closure. | Within 60 days after plugging or at the time of the next quarterly report (whichever is less), owner/operator must submit a certified plugging report to the Director. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | As a part of the permit application, develop and submit a plan for Director approval to address PISC and site closure requirements and monitoring, for 10 years after project closure. | As a part of the permit application, develop and submit a plan for Director approval to address PISC (and monitoring) and closure requirements, for 50 years after cessation of injection.<br>The plan should include the:<br>▪ Pressure differential between pre-injection and post-injection pressures in the injection zone<br>▪ Predicted position of the $CO_2$ plume and pressure front<br>▪ A description of post-injection monitoring (location, methods, and frequency)<br>▪ A proposed schedule for submitting monitoring results to the Director.<br><br>Upon cessation of injection, the plan should be re-approved by the Director, amended or original.<br><br>The default PISC period is 50 years; data submitted as part of the permit application, or collected during PISC and submitted to the Director can be used to request a shorter PISC period, subject to Director approval. At the end of the PISC period, a non-endangerment demonstration will be performed and the director will determine if further monitoring is necessary. | As a part of the permit application, develop and submit a plan for Director approval to address PISC (and monitoring) and closure requirements, for 100 years after cessation of injection.<br>The plan should include the:<br>▪ Pressure differential between pre-injection and post-injection pressures in the injection zone<br>▪ Predicted position of the $CO_2$ plume and pressure front<br>▪ A description of post-injection monitoring (location, methods, and frequency)<br>▪ A proposed schedule for submitting monitoring results to the Director.<br><br>Upon cessation of injection, the plan should be re-approved by the Director, amended or original.<br><br>After 100 years (or before or after with Director approval), a non-endangerment demonstration will be performed and the director will determine if further monitoring is necessary. |
| | Conduct post-inject site monitoring per the Director-approved plan to confirm that $CO_2$ movement is limited to intended zones | Conduct post-injection site monitoring per the Director-approved plan (which may include pressure fall-off test; seismic monitoring, if appropriate; monitoring in and above the injection zone and the USDW) to confirm that $CO_2$ movement is limited to intended zones. | Conduct post-injection site monitoring per the Director-approved plan (which may include pressure fall-off test; seismic monitoring, if appropriate; monitoring in and above the injection zone and the USDW) to confirm that $CO_2$ movement is limited to intended zones. |
| | | After site-closure is authorized by the Director, plug all monitoring wells in a manner that will prevent endangerment of USDWs. | After site-closure is authorized by the Director, plug all monitoring wells in a manner that will prevent endangerment of USDWs. |
| | | Submit a site closure report to the Director within 90 days, that must be retained for ten years, that includes: documentation of (all) well plugging; submission of a survey plat to specified parties; documentation of notification to parties that may have authority over future drilling activities in the AoR; records reflecting $CO_2$ characteristics | Submit a site closure report to the Director within 90 days that includes: documentation of (all) well plugging; submission of a survey plat to specified parties; documentation of notification to parties that may have authority over future drilling activities in the AoR; records reflecting $CO_2$ characteristics |
| | | Record a notation on the deed to the facility property indicating that the land was used for GS; name of authority with which survey plat was filed; injection volume, zones, and duration. | Record a notation on the deed to the facility property indicating that the land was used for GS; name of authority with which survey plat was filed; injection volume, zones, and duration. |

| REGULATORY ALTERNATIVE 1 | REGULATORY ALTERNATIVE 2 | REGULATORY ALTERNATIVE 3 | REGULATORY ALTERNATIVE 4 |
|---|---|---|---|
| | | Retain for 10 years following site closure, and, after three years deliver to the Director, records of the nature, composition, and volume of the $CO_2$ stream. | Retain for 3 years following site closure, and, after three years deliver to the Director, records of the nature, composition, and volume of the $CO_2$ stream. |
| **Financial Responsibility** | | | |
| | Provide through a performance bond, or other appropriate means, the resources necessary plug the well. | Demonstrate and maintain financial responsibility and resources for plugging the well, corrective action, remediation and providing post-injection site monitoring and closure, accounting for inflation. | Demonstrate and maintain financial responsibility for plugging the well, corrective action, remediation and providing post-injection site monitoring and closure, accounting for inflation. |
| **Emergency and Remedial Response** | | | |
| | | As a part of the permit application, develop and submit an emergency and remedial response plan for Director approval that describes actions to be taken to address movement of injection or formation fluids that may endanger USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. | As a part of the permit application, develop and submit an emergency and remedial response plan for Director approval that describes actions to be taken to address movement of injection or formation fluids that may endanger USDWs. |
| | | If evidence shows potential endangerment of USDWs, the owner or operator should cease injection; notify the Director; investigate and identify $CO_2$ release; implement the emergency and remedial response plan;<br>And, prior to re-commencing injection, demonstrate to the Director non-endangerment to USDWs. | If evidence shows potential endangerment of USDWs, the owner or operator should, cease injection; notify the Director; investigate and identify $CO_2$ release; implement the plan; implement the emergency and remedial response plan;<br>And, prior to re-commencing injection, demonstrate to the Director non-endangerment to USDWs. |
| | | Notify the Director and obtain approval for well workovers. | Notify the Director and obtain approval for well workovers. |
| | | Periodically review the emergency and remedial response plan at least once every five years. Any amendments to the emergency and remedial response plan must be approved by the Director and shall be submitted within one year of an AOR re-evaluation. | |

## 2.4 Final Rule Requirements

EPA selected RA3 as the best alternative for the final rule. Compared to the baseline condition of the current UIC Program regulations, RA3 offers significantly greater protection to USDWs because it is tailored specifically to GS and includes requirements necessary to prevent endangerment via migration of fluids into USDWs than RA1 and RA2 Additionally, RA3 offers greater protection over the baseline (Class I non-hazardous wells) because the RA3 requirements are tailored to address the unique nature of injection of CO2 for the purposes of GS. This alternative also incorporates flexibility or Director's discretion wherever appropriate. RA4 provides the most reduction in risks and overall costs because it prescribes the most stringent standards. However, EPA does not believe that the increased requirements under RA4 compared to RA3 are necessary to provide the necessary protection to USDWs. Detailed results of the costs for the regulatory alternatives considered are provided in Chapter 5 and Appendix C of this Cost Analysis.

# 3. Baseline Analysis

## 3.1 Introduction

This chapter describes the carbon dioxide ($CO_2$) geologic sequestration (GS) projects that form the baseline incorporated into the GS Rule Cost Analysis including their hydrogeologic characteristics and other project characteristics affecting the costs of the rule. It presents the data sources for the baseline information and an overview of the uncertainty associated with these data. The United States Environmental Protection Agency (EPA) has estimated the characteristics for a representative group of projects that are expected to deploy under existing legislation over the 50-year period of analysis of the GS Rule. This chapter summarizes the information relevant to the cost analysis presented in Chapter 5, and is organized as follows:

- **Section 3.2** describes the data sources used to inform development of the project baseline. These sources include published data sources, data from current pilot projects submitted by Department of Energy (DOE), and laboratory data.

- **Section 3.3** provides background that describes the various types and distribution of hydrogeologic settings identified as potential receiving formations for $CO_2$ injected for the purpose of GS in the U.S.

- **Section 3.4** introduces the group of GS projects constituting the baseline by size of project and type of receiving formation, and presents characteristics for each type of project.

- **Section 3.5** identifies the sources of uncertainty in the baseline analysis.

## 3.2 Data Sources

EPA used a variety of data sources to create baseline forecasts for the cost analysis, including data published/collected by DOE, industry, and academia, pilot project data and laboratory data from efforts by DOE in conjunction with seven $CO_2$ GS Regional Carbon Sequestration Partnerships (RCSPs). These data sources are described below.

### 3.2.1 Published Data

Over the past several years, DOE and seven regional sequestration partnerships (comprising private sector, academia, and government representatives) have assessed and characterized the potential $CO_2$ sequestration capacity in the United States. Through their efforts, DOE published the National Carbon (NATCARB) Atlas (DOE, 2008), which categorizes GS potential by geologic setting and geologic basin or State, often providing the data in geographic information system (GIS) format. The NATCARB Atlas also presents information on the research conducted regarding various potential receiving formations, and includes an estimated total U.S. $CO_2$ GS capacity of approximately 3,500 gigatons (Gt) although the actual capacity may be lower once site-specific technical and economic considerations are addressed.

To estimate non-DOE large-scale projects, EPA consulted sources including the Carbon Sequestration Leadership Forum (CSLF) Carbon Capture and Storage Demonstration Database (updated June, 2009), which EPA downloaded[1] and filtered for U.S. based projects of a significant scale.[2]

### 3.2.2 Department of Energy Pilot Project Data

The research sponsored by DOE began in 2003 with the Characterization Phase, in which the National Energy Technology Laboratory (NETL) in Morgantown, West Virginia and the seven regional partnerships conducted the geologic analysis that resulted in the NATCARB Atlas described above. During the Validation Phase (2005-2009), field researchers conducted validation tests of reservoir simulation methods, data collection methods for capacity and injectivity, and the performance of monitoring technologies. The partnerships are also field testing approaches to well completion methods, operations, and site closure, with a variety of objectives including:

- Testing the effectiveness of various well materials and injection practices;
- Validating models of the fate and transport of $CO_2$ in the subsurface;
- Developing a thorough understanding of the geology, hydrogeology, and geochemistry at potential GS sites;
- Assessing the usefulness of geophysical survey and monitoring techniques;
- Testing failure scenarios;
- Developing experience necessary for deployment of large-scale $CO_2$ GS; and
- Building public confidence that GS can be performed without adverse risks.

The results of research at three of these sites (in Escatawpa, Mississippi; the Aneth Field in the Paradox Basin, Southeast Utah; and the Pump Canyon Site, New Mexico) were presented in EPA's August 31, 2009 Notice of Data Availability (NODA) (74 FR 44802).

During the Deployment Phase (2008-2017), the partnerships are conducting large volume carbon storage tests to demonstrate that large-scale $CO_2$ injection and storage can be achieved safely and economically.

[1] http://www.cslforum.org/projects/index.html

[2] For the purposes of this analysis, a threshold of 1 million tons $CO_2$ per year injection volume was used to determine those projects likely to be large-scale.

### 3.2.3 DOE Inventory Data

EPA consulted with DOE in conjunction with the partnerships to inform the baseline number of GS projects estimated to deploy in the U.S. over the timeframe of this analysis. DOE relied on information about existing projects, funding estimates and discussions with members of the regional partnerships to develop the projected baseline inventory and associated project data elements (e.g., duration and volume of injection, formation type, etc.).

### 3.2.4 Laboratory Research

EPA and DOE have co-funded research by the Lawrence Berkeley National Laboratory (LBNL) to study and evaluate the physiochemical processes of $CO_2$ injection and to explore any potential impacts on ground water aquifers and drinking water sources. Current research includes the following:

- Modeling potential impacts of $CO_2$ injection on ground water aquifers and drinking water sources;
- Assessing potential changes in regional ground water flow, including displacement of pre-existing saline water or hydrocarbons that could impact underground sources of drinking water (USDWs) or other resources; and
- Integrating laboratory, field and modeling efforts with the objective of evaluating the potential consequences of $CO_2$ leaks from GS operations into ground water resources.

The results of some of this research were published in the NODA. See Section 2.2 of this Cost Analysis for additional information. Information gained from this research will be used to evaluate potential risks and develop safeguards to protect USDWs from endangerment. As described in the preamble to the final GS Rule, EPA plans to adapt the rule over time as relevant information emerges from research and from GS field experience.

## 3.3 Hydrogeologic Settings

The various hydrogeologic settings of the formations across the U.S. that may serve as targets for long-term GS represent a significant range of storage potential, geographic location, and technical and economic merits, which could all affect the potential costs of GS. The variables that define the hydrogeologic setting include the type and properties of injection zone and confining formation, other components of the reservoir overburden, the location of current or potential USDWs, and the presence of artificial penetrations, fractures, or other potentially vulnerable attributes of the system. These variables are important in determining project parameters such as the required minimum depth of the injection well (or whether an injection depth waiver will be sought); the minimum number of monitoring wells; and maximum injection rates, volumes, and pressures. The geographic location of the potential injection zones can also determine the feasibility of injection projects depending on the location of the $CO_2$ source. Although the costs of $CO_2$ transport do not fall within the scope of this rule, the locational advantages of one type of formation over another will be an important consideration in the siting of the forecasted projects that compose the baseline of this Cost Analysis.

### 3.3.1 Formation Types

The requirements in the final rule are designed to ensure protection of USDWs through proper siting, well construction, operation, monitoring, and post-injection site care (PISC) at all sites selected for GS irrespective of formation type. For the purpose of conducting this Cost Analysis, EPA has identified several types of geologic formations that may serve as suitable formations for sequestering $CO_2$.[3]

*Saline Formations*

Saline formations are deep and geographically extensive water-saturated rock layers with a high total dissolved solids (TDS) content (i.e., over 10,000 ppm TDS). Using volumes from the *Carbon Sequestration Atlas of the United States and Canada* (DOE, 2007b) EPA estimates that between 91.8 and 97.6 percent of potential GS storage capacity is in deep saline formations. Their geographic distribution covers all regions of the U.S. and because many are overlain by impermeable formations it makes them leading candidates for GS. Many are in close proximity to major $CO_2$ stationary sources, which has the potential to substantially lower $CO_2$ transportation costs. However, because they are currently of limited economic value (i.e., they are not used as drinking water sources or contain any mineral resources), most saline formations are not as well studied as other formation types being considered for GS. Pilot tests are currently being performed in saline formations to further evaluate their large-scale GS potential.

*Oil and Gas Reservoirs*

Enhanced oil recovery (EOR) and enhanced gas recovery (EGR) technologies, collectively referred to as enhanced recovery (ER), are used in oil and gas reservoirs to improve production efficiency. Injection of $CO_2$ is one of several ER techniques that have successfully been used to boost production efficiency of oil and gas by re-pressurizing the reservoir, and in the case of oil, by also increasing its mobility. Injection wells used for ER are regulated through the Underground Injection Control (UIC) Class II program.

Oil and gas reservoirs are very well studied and understood due to the amount of research needed for oil and gas exploration, and account for between 1.1 to 3.8 percent of the potential storage capacity in the U.S. (DOE, 2008). The volumes of $CO_2$ to be injected and left behind in the formation for the purpose of GS would be much greater than traditionally seen in $CO_2$ enhanced oil and gas recovery operations. Geographic distribution of oil and gas reservoirs corresponds to areas that have been drilled for oil and gas in the past including Appalachia, the Gulf Coast, Mid-Continent, and the Rockies.

*Unmineable Coal Seams*

$CO_2$ may be injected into coal seams to displace methane that adsorbs onto the surface of the coal, provided injection does not endanger USDWs; such formations account for approximately 1.4 – 4.4 percent of the potential U.S. storage capacity (DOE, 2008). DOE estimates that for every molecule of methane displaced in enhanced coal bed methane (ECBM)

[3] $CO_2$ injection in certain situations such as for the purpose of enhanced oil and gas recovery (ER) operations may not be covered under the GS rule. The preamble provides a full discussion of applicability under the GS rule for different injection scenarios.

operations, three to thirteen $CO_2$ molecules are adsorbed. (DOE OFE, 2007) This process allows the methane to be captured and produced for economic purposes. Coalbed methane potential is concentrated in the areas of New Mexico and Wyoming. There are currently no large-scale $CO_2$ ECBM projects, but DOE reports that initial field studies have demonstrated that $CO_2$ ECBM and GS into coal seams is technically feasible.

*Other Formation Types*

Other types of formations such as basalts, organic rich shales, and abandoned mines also could potentially serve as $CO_2$ reservoirs, provided injection does not endanger USDWs. In particular, shale gas is important to consider. The new shale gas basins that have emerged over the past decade are not as well studied and are not believed to be as technologically or economically feasible as saline formations, oil and gas reservoirs, and unmineable coal seams for GS. Research is ongoing in these formations and their viability as sequestration sites has not been proven. Therefore, EPA expects that $CO_2$ injection into these types of formations will be permitted as Class V experimental technology wells.

### 3.3.2 Formation Capacity

EPA has developed estimates of the total U.S. $CO_2$ storage potential by type of injection formation. This estimate extrapolates from prior NATCARB estimates into the previously excluded geographic areas of the United States to yield a total U.S. estimate of 3,374 Gt. Deep saline formations account for the largest estimated potential $CO_2$ storage at 2,990 Gt, followed by oil and gas at 126 Gt, shale formations at 107 Gt, coal and coalbed methane at 51 Gt, and onshore saline-filled basalt at 100 Gt.

## 3.4 Geologic Sequestration Rule Baseline

This analysis estimates the anticipated level of GS activity in the United States under the existing regulatory conditions, as per EPA guidelines on economic analysis. In this baseline analysis, the Agency assumes that there will be no new national climate change legislation. In the absence of the development of new requirements for GS wells, EPA anticipates that GS wells would be permitted as Class V experimental technology wells, in accordance with UIC Program Guidance #83. This class of wells affords the UIC primacy agency discretion to issue permits that meet site-specific conditions for experimental projects. Based on review of early permits issued, the permit conditions for existing Class V experimental technology wells that test GS technology have been similar in stringency to those for Class I industrial wells, which will provide USDWs with protection that meet the goals of the Safe Drinking Water Act (SDWA). Specific requirements that may involve a great deal of discretion and thus greater variability in implementation (e.g., area of review (AoR) determinations) can have a significant impact on the amount of USDW protection under a particular permit.

This cost analysis includes estimated costs projected over a 50-year instead of a 25-year time period, as is normally performed for EPA drinking water regulations. EPA elected to increase the analysis period to better reflect the lifecycle costs of GS projects. For large projects, this includes 1 year of construction, 40 years of injection, and 9 years of post-closure monitoring which concludes the timeframe of analysis. For pilot projects, this analysis captures the entire 15 year period, including 1 year of construction, 4 years of injection, and 10 years of post closure

monitoring. For projects in oil and gas reservoirs transitioning to GS, this includes 20 years of operating for the primary purpose of oil and gas production under an existing UIC Class II permit, and 10 years under Class VI permit where the primary purpose is long-term storage.

### 3.4.1 Projects Comprising the Baseline

Based on analysis of existing data obtained from DOE on GS and current pilot programs as described in Section 3.2, EPA assumes there will be 29 projects for the baseline that are anticipated to be affected by the GS rule. These projects include 2 DOE-sponsored pilot saline projects, 8 large-scale DOE-sponsored projects in saline formations, and 4 projects at ER sites for a total of 14 DOE-sponsored projects. In addition, EPA estimates from the CSLF database as described in Section 3.2 that 15 projects not sponsored by DOE should be included in the baseline: 3 saline and 12 ER.

Projects permitted prior to the finalization of the GS rule will be managed under existing UIC Program requirements and are not included in this baseline. Initially, the primary purpose of ER projects will continue to be oil and gas production, thus $CO_2$ sequestration (as the primary purpose) is modeled to start later in the analysis period compared to other project types. Exhibit 3.1 summarizes the forecast for deployment of these projects by type of project and project scale (pilot vs. large) over 50 years.

## Exhibit 3.1 Schedule of Baseline Project Deployment by Formation Type and Project Size

| Year | Type of Formation | | | | |
|---|---|---|---|---|---|
| | Saline Formations | | | Enhanced Recovery | |
| | Pilot Project | Large Project | Waivered Saline | ER | Waivered ER |
| 2011 | - | - | - | - | - |
| 2012 | - | 0.86 | 0.05 | - | - |
| 2013 | - | 0.86 | 0.05 | - | - |
| 2014 | - | 1.71 | 0.10 | - | - |
| 2015 | - | - | - | - | - |
| 2016 | - | 1.71 | 0.10 | - | - |
| 2017 | 2 | 4.28 | 0.24 | - | - |
| 2018 | - | - | - | - | - |
| 2019 | - | - | - | - | - |
| 2020 | - | - | - | - | - |
| 2021 | - | - | - | - | - |
| 2022 | - | - | - | - | - |
| 2023 | - | - | - | - | - |
| 2024 | - | - | - | - | - |
| 2025 | - | - | - | - | - |
| 2026 | - | - | - | - | - |
| 2027 | - | - | - | - | - |
| 2028 | - | - | - | - | - |
| 2029 | - | - | - | 0.86 | 0.05 |
| 2030 | - | - | - | - | - |
| 2031 | - | - | - | 0.86 | 0.05 |
| 2032 | - | - | - | 3.42 | 0.19 |
| 2033 | - | - | - | 2.57 | 0.14 |
| 2034 | - | - | - | 0.86 | 0.05 |
| 2035 | - | - | - | 1.71 | 0.10 |
| 2036 | - | - | - | 2.57 | 0.14 |
| 2037 | - | - | - | 0.86 | 0.05 |
| 2038-2060 | - | - | - | - | - |
| Total | 2.0 | 9.4 | 0.5 | 13.7 | 0.8 |

Notes:
1) Numbers may not add due to rounding.
2) Estimates represent modeled parameters, and therefore do not represent any one individual project and are generally not whole numbers.
3) Under RA3, it is estimated that 26.4 of the 29 baseline projects will successfully deploy over the 50 year period of analysis. Chapter 5 of this Cost Analysis describes the deployment assumptions in more detail.
4) This analysis covers a 50 year timeframe, and includes construction, injection, and post-injection monitoring phases for projects in each of the different formations. Depending on when a given GS project begins, some of the post-injection monitoring may fall outside of the 50 year timeframe of this analysis.
5) On an annual basis, large saline projects are expected to inject more CO2 than pilot saline projects or ER projects.

### 3.4.2 Project Characteristics

Exhibit 3.2 summarizes the project characteristics that drive differentials in costs for the baseline projects. Some items, such as the costs of permitting, are expected to be fairly uniform, regardless of project type. However, characteristics such as storage capacity, injection depth, and storage efficiency are all affected by the local geologic conditions. Additional information on the derivation of the estimates presented in Exhibit 3.2 can be found in the *Geologic $CO_2$ Sequestration Technology and Cost Analysis* (EPA, 2010a).

## Exhibit 3.2 Project Characteristics By Formation Type and Size

| Characteristic | Type of Project | | | | |
|---|---|---|---|---|---|
| | Saline | | | | |
| | Pilot | Large | Large Waivered | ER | ER Waivered |
| Depth to Top of Injection Interval (ft) | 7,900 | 7,900 | 4,400 | 5,700 | 3,312 |
| Depth to Bottom of Injection Interval (ft) | 8,500 | 8,500 | 5,000 | 5,800 | 3,412 |
| Metric tonnes capacity at 100% storage efficiency | 30,022,272 | 737,154,000 | 737,154,000 | 32,574,981 | 29,860,399 |
| Storage efficiency | 10.0% | 10.0% | 10.0% | 49.4% | 49.4% |
| Area of Review ($mi^2$) [4] | 0.9 | 23.3 | 23.8 | 8.4 | 8.2 |
| Total Number of wells in Area of Review | 5 | 116 | 119 | 167 | 165 |
| Injection Wells Required (total) | 3 | 4 | 4 | 17 | 16 |
| Tubing Diameter (inches) | 6 | 6 | 6 | 4 | 4 |
| Depth of Stratigraphic Tests (ft.) | 2,400 | 9,350 | 5,500 | 2,400 | 2,400 |
| Number of Monitoring Wells above Injection Zone[1] | 1.0 | 5.8 | 8.7 | 2.1 | 3.1 |
| Number of Monitoring Wells into Injection Zone[1] | 1.0 | 5.8 | 8.7 | 2.1 | 3.1 |
| Depth of Monitoring Wells[2] (feet) | 5,783 | 5,783 | 4,783 | 4,192 | 3,266 |
| Long-string Casing of Monitoring Wells (diam. inches) | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 |
| Injection Period (years)[3] | 4 | 40 | 40 | 10 | 10 |

Source: Appendix A

Notes:

(1) The number of monitoring wells per site varies according to the RA and the size of the project area assumed for a representative project. Shown are the required number of wells in the pro forma of each project type for the selected RA (RA3).

(2) Well depths shown represent the typical (mean) monitoring well depth. Shown are the figures for RA3. Under RA3 and RA4, one half of the monitoring wells would be drilled to the bottom of the injection zone, while the other monitoring wells for RA3 and RA4, and all monitoring wells for RA1 and RA2, would be drilled to a depth halfway between the bottom of the lowest USDW and the top of the containment formation.

(3) GS projects in oil and gas reservoirs are assumed to operate for 30 years: 20 years under the existing UIC class II well regulations while the site is still used primarily for oil/gas production, and for the remaining 10 years under class VI for the primary purpose of long-term storage. This cost analysis includes costs for ER projects beginning with their transition from production to GS, i.e., 20 years into the 30 year injection period.

(4) The Area of Review is the size of the area estimated to encompass the plume throughout the project lifecycle.

(5) Projects that receive approval of a waiver of the requirement to inject below the lowermost USDW have reduced depth and a higher number of monitoring wells; this information is provided in the pro forma sheets presented in Appendix A of this Cost Analysis.

## 3.5 Sources of Uncertainty

Because of the nascent nature of the climate change legislative landscape, the number and characteristics of projects comprising the baseline represent a source of uncertainty in this Cost Analysis. Pilot projects are defined by the type of geologic formation that will receive the $CO_2$, the number of injection wells, the volume of $CO_2$ to be injected, and the length of the injection period, all of which are incorporated into the baseline estimate for the GS Rule Cost Analysis. Some parameters, such as the number of projects and the length of the injection period, represent direct multipliers used to develop costs in this analysis. For example, a doubling of the number of projects (all else being equal) would double the estimated cost of the regulation, assuming the costs of those projects are not attributable to another regulation. Other uncertainties affect unit cost estimates, which have a less direct impact on the regulation cost; there are more than 100 unit costs, and doubling one of them has a relatively small impact on total cost. For example, injection volumes would influence injection rates, the needed areal extent of the $CO_2$ injection zone, and the size of the AoR, which in turn influences unit cost parameters such as the cost of corrective action, the numbers of injection and monitoring wells deployed, and operation and maintenance costs.

At this time, the Agency regards the baseline estimates presented in this chapter as reasonable and representative of the current industry status. Depending on how many of these projects actually deploy during the 50-year period of analysis and the associated characteristics of those projects, the baseline estimates used in this Cost Analysis may result in an over- or underestimate of GS Rule costs. Detailed discussion and analyses considering the uncertainty in the total number of projects, the labor rates used in the Cost Analysis, and the number of monitoring wells per project site are presented in Section 5.9.2 of this Cost Analysis.

# 4. Benefits Analysis

## 4.1 Introduction

The regulatory alternatives (RAs) considered during the development of the Federal Requirements under the Safe Drinking Water Act (SDWA) for underground injection of carbon dioxide ($CO_2$) for the purposes of Geologic Sequestration (GS Rule) were designed to protect underground sources of drinking water (USDWs). This protection is the direct benefit of the GS Rule. Each of the alternatives considered provides a level of USDW protection that corresponds to the stringency of the requirements of that alternative. This chapter uses a qualitative approach to examine the risk tradeoffs between compliance with existing requirements, (i.e., the regulatory baseline) and the four regulatory alternatives considered.

The regulatory baseline, for the purpose of this analysis, consists of Agency estimates of the decisions regarding GS projects permitting authorities and owners and operators would have made under current Underground Injection Control (UIC) Program regulations. The Agency assumes that, absent a GS rule, permitting authorities would issue permits with conditions that are similar in stringency to those for Class I industrial waste disposal wells. A review of permits issued to early pilot projects indicates that this is the case. Current permits require that these projects have siting, construction, operating (i.e., injection below the lowermost USDW), and monitoring and testing requirements that match Class I requirements. Consistent with *UIC Program Guidance # 83,* some of these wells are classified as Class V experimental technology wells; however they have permit conditions that meet the requirements of Class I non-hazardous wells.

As described in Section 4.2.11 of this chapter, this qualitative consideration of reduction in risks to USDWs under each alternative relative to the baseline scenario indicates that risks are reduced the most under RA4, the most prescriptive of the alternatives, and least under RA1 and RA2. While this analysis shows that both RA3 and RA4 significantly increase protection of USDWs over baseline and over RA1 and RA2, EPA does not believe that the increased requirements under RA4 as compared to RA3 are necessary to provide the necessary protection to USDWs. Therefore the United States Environmental Protection Agency (EPA) has selected RA3 as the best alternative.

## 4.2 Relative Risks – Qualitative Analysis

The direct benefit of the GS Rule is the protection of USDWs from potential contamination related to the GS activity. Due to the anticipated large $CO_2$ injection volumes associated with GS, the buoyant and mobile nature of the injectate and its corrosivity in the presence of water, EPA has determined that tailored requirements, modeled on the existing UIC regulatory framework, are appropriate for wells injecting $CO_2$ for GS.[1] Because GS is still in the early phases of deployment, quantitative correlations between GS project components, such as site characteristics or operating parameters, and the incidence of migration of fluid away from the injection site or leakage from the borehole are not available. This limited availability of data

[1] A detailed description of these concerns is provided in section II.3 of the Preamble for the GS Rule.

precludes development of a quantitative risk analysis with regard to the probability of contamination. However, considerable work has been done to qualitatively assess the vulnerabilities in various geologic settings for GS projects that could result in an increased probability of leakage or fluid migration away from the injection zone or borehole. Further evaluation of these potential risks is provided in the *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide* (USEPA, 2010c). Section 4.3 of this document discusses these vulnerabilities and the broader ramifications of such contamination on the ecological and human environment, the protection of which is largely outside the statutory authority of the SDWA (except as it relates to protection of USDWs) but is included here to provide for a broader understanding of the nature of the risk from GS.

The current assumptions are that: 1) $CO_2$ injection could cause the movement of brine or brackish water into a USDW, thereby requiring further treatment of that water to meet drinking water requirements; and 2) the presence of $CO_2$ and associated impurities could acidify formation fluids or the soil or rock matrix, and could mobilize arsenic or other drinking water contaminants that were previously adsorbed to the soil/rock matrix into the ground water. Since these risks are not yet quantified, the information available is not conducive to quantifying the potential costs avoided by mitigating them.

It should be noted that this analysis is not intended to quantify the magnitude of the increase or decrease in risk relative to the baseline or determine which requirements have the greatest effect on the increase/decrease in risk relative to baseline or each other. Because of the limited implementation of GS projects, particularly at the scales intended at full deployment, no data exist to support a quantitative analysis of which requirements (or lack thereof) would decrease or increase risk to the greatest extent.

This analysis instead presents the estimated direction of change in risk for regulatory alternatives of the GS Rule considered relative to the existing (baseline) conditions. The term “baseline” in this chapter refers to risks as they exist under current regulations, which are summarized in the first column of Exhibit 4.1. The terms “increase,” “decrease,” and “no change,” indicate the direction of risk change when comparing the regulatory alternatives to the baseline, and not the magnitude of any such change. A discussion of risk change associated with each of the regulatory components presented follows Exhibit 4.1.

## Exhibit 4.1 Estimated Change in Risk for Components of the RAs Compared to the Regulatory Baseline

| BASELINE | Risk Change Relative to Baseline for RAs Considered | | | |
|---|---|---|---|---|
| | Alternative 1 | Alternative 2 | Alternative 3 | Alternative 4 |
| **1. Site Characterization** | | | | |
| Geologic system consisting of an injection zone; trapping mechanism; and confining system to allow injection at proposed rates and volumes.<br><br>Provide maps and cross sections of local and regional geology, Area of Review (AoR), and USDWs; characterize the overburden and subsurface; and provide information on fractures, stress, rock strength, and in situ fluid pressures within cap rock and storage reservoir. | Increase | Increase | Decrease | Decrease |
| **2. AoR and Corrective Action** | | | | |
| AoR is either a ¼ mile radius or determined by mathematical formula. Identify all wells in the AoR that penetrate the injection zone and provide a description of each; identify the status of corrective action for wells in the AoR; and remediate those posing the risk to USDWs. | Increase | Decrease | Decrease | Decrease |
| **3. Injection Well Construction** | | | | |
| The well must be cased and cemented to prevent movement of fluids into or between USDWs and to withstand the injected materials at the anticipated pressure, temperature and other operational conditions. The well must be below the lowermost USDW. | Increase | Decrease (enhanced well construction requirements)<br><br>Increase (waiver to inject above lowermost USDW in limited cases) | Decrease (enhanced well construction requirements)<br><br>Increase (waiver to inject above lowermost USDW in limited cases) | Decrease |
| **4. Injection Well Operation** | | | | |
| Limit injection pressure to avoid initiating new fractures or propagating existing fractures in the confining zone adjacent to the USDWs. | Increase | Increase | Decrease | Decrease |
| **5. Mechanical Integrity Testing (MIT)** | | | | |
| Demonstrate internal mechanical integrity (MI) every 5 years. Conduct a pressure fall-off test every 5 years. | Increase | Increase | Decrease | Decrease |
| **6. Monitoring** | | | | |
| Monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics. Conduct ground water monitoring within the AoR. Report quarterly on the characteristics of injection fluids, injection pressure, flow rate, volume and annular pressure, and the results of MITs. | Increase | Increase | Decrease | Decrease |

| BASELINE | Risk Change Relative to Baseline for RAs Considered | | | |
|---|---|---|---|---|
| | Alternative 1 | Alternative 2 | Alternative 3 | Alternative 4 |
| **7. Well Plugging, Post-Injection Site Care (PISC), and Closure** | | | | |
| Ensure that the well is in a state of static equilibrium and plugged using approved methods. Plugs shall be tagged and tested. Conduct post-injection monitoring to confirm that $CO_2$ movement is limited to intended zones. | Increase | Decrease | Decrease | Decrease |
| **8. Financial Responsibility** | | | | |
| Demonstrate and maintain financial responsibility and resources to plug and abandon the injection well. | Increase | No Change | Decrease | Decrease |
| **9. Emergency and Remedial Response** | | | | |
| No specific requirement. | No Change | No Change | Decrease | Decrease |
| **Overall** | **Increase** | **Decrease** | **Decrease** | **Decrease** |

Note: See Chapter 2 for a detailed description of the components of each regulatory alternative.

### 4.2.1 Site Characterization

Under current regulations, owners and operators of GS wells would need to demonstrate that the injection site is in an area with geologic formations that can receive and confine the injected fluids below USDWs such that these fluids remain isolated in order to ensure protection of USDWs from endangerment. Owners and operators must provide maps and cross sections of local geologic structure, USDWs, and the AoR and characterize the overburden using data on size, capacity, porosity, and permeability and geomechanical information on fractures, stress, rock strength, and in situ fluid pressures within the cap rock and storage reservoir.

Compared to this baseline, RA1 increases risk because the performance standard that wells be sited in a manner that protects USDWs from endangerment is subject to considerable interpretation on the part of the owner and operator and permitting authority; this may result in a certain portion of owners and operators not characterizing the site as thoroughly as described in the baseline, which could potentially result in injection at a site with fewer of the protective safeguards that are necessary, given the unique nature of the $CO_2$ injectate (as described in Section 4.2).

RA2 does prescribe some requirements regarding the geological data to be provided, but these are slightly less prescriptive than the baseline. Given the importance of a detailed site-specific geologic characterization to selecting an adequate GS site, the lack of detail in RA2 may increase risk relative to the baseline.

RA3 and RA4 both have requirements that are more stringent and specific than the baseline. Under these alternatives the owners and operators of GS wells would be required to perform a detailed assessment of the geologic, hydrogeologic, geochemical and geomechanical properties of the proposed GS site to ensure that the wells are sited in appropriate locations and inject into suitable formations. Additionally, some GS owners and operators would have to identify additional zones above the confining zone that will impede vertical fluid movement, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation. Characterizing these layers would be at the Director's discretion in RA3 and required for all GS sites in RA4. Further, many of the specific site characterization requirements

in RA3 and RA4 more adequately address the unique nature of $CO_2$ injection for GS, such as: requirements for structural and hydrogeologic data, seismic history, geomechanical data, and identification and evaluation of faults and fractures. Additionally, RA4 would require owners and operators to further characterize the overburden using geologic cores, outcrop data, 3-dimensional seismic surveys, and well logs and, at the Director's discretion, drill a stratigraphic test well to provide more detailed baseline data on subsurface formations. Because a more detailed site characterization improves the owners and operator's and Director's ability to evaluate the presence (or absence) of necessary protective geologic elements, the greater detail involved in characterizing the site under these RAs will likely decrease risk to USDWs relative to the baseline.

### 4.2.2 Area of Review (AoR) and Corrective Action

Under current Class I non-hazardous regulations, the AoR for a GS site would be either a ¼ mile radius around the injection well or would be delineated by a mathematical formula. Within the delineated AoR, owners and operators must identify all wells that penetrate the injection zone and provide information about each well's type, construction, depth, and plugging, and identify which wells require corrective action. Wells in the AoR that pose a risk to USDWs must be addressed using appropriate corrective action methods.

RA1 does not specify a minimum size of the AoR or methods for delineating the AoR; additionally this RA does not include specific requirements for identifying and addressing improperly plugged wells in the AoR. Due to this lack of specificity and the potential to inadequately address all conduits for fluid movement to USDWs, RA1 may further increase risk relative to the baseline.

Under RA2, owners and operators would define the AoR based on a calculated fixed radius or by modeling. Assuming that some owners and operators choose to develop a model, this represents a slight decrease in risk from baseline. Within the defined AoR, owners and operators must identify all artificial penetrations; determine, based on publicly available data, whether abandoned wells have been plugged in a manner that prevents the movement of $CO_2$ or associated fluids from the storage reservoir; and employ corrective action at those wells that pose a risk to USDWs using appropriate methods determined in consultation with the permitting authority. Because they directly address the potential for USDW contamination via abandoned wells, the additional requirements under RA2 result in a decrease in risk relative to the baseline regulatory requirements.

RA3 and RA4 may further decrease risk by requiring owners and operators to define the AoR using sophisticated computational models based on site specific data that accounts for multiphase flow and the buoyancy of $CO_2$. This type of modeling is the most accurate tool available for predicting the migration of the $CO_2$ plume and associated pressure front in the subsurface until the plume movement ceases and pressures stabilize, or for a fixed time period determined by the Director. (RA4 would require that the models predict plume and pressure front movement over 10,000 years.) Additionally, the use of computational models improves predictions of the extent and direction of the $CO_2$ plume and pressure front to allow better targeting of corrective action and monitoring. Because using a fixed radius would under-represent the size and shape of the large volumes of injected $CO_2$, the requirement to delineate the AoR using computational modeling decreases risk relative to baseline. This is because GS

projects would likely have an AoR much larger and less uniform in size than ¼ mile AoR due to the large volumes injected and buoyancy of $CO_2$.

As in RA2, RA3 and RA4 would require owners and operators to identify all well penetrations in the AoR, determine if they have been plugged in a manner that prevents fluid movement, and apply corrective action to those wells as needed. RA3 and RA4 are more specific in that they require that corrective action be performed using materials that are compatible with $CO_2$, therefore reducing risk of degrading existing well materials that come in contact with injected $CO_2$. These alternatives also allow owners and operators to "phase" corrective action (if allowed by the Director); this is not anticipated to increase or decrease risk relative to the baseline.

Finally, RA3 and RA4 would require owners and operators to periodically reevaluate the AoR over the life of the injection project to account for any operational changes and incorporate monitoring data. Both RA3 and RA4 require this reevaluation at least every five years, or whenever operational changes or monitoring data dictate a need. This reevaluation would help owners and operators to verify that the $CO_2$ plume is moving as predicted or provide an opportunity to adjust the injection operation, monitoring, or corrective action to address changes in the predicted AoR and therefore would reduce risk relative to baseline.

### 4.2.3 Injection Well Construction

For well construction activities, the baseline specifies that GS wells must be below the lowermost USDW and be cased and cemented to prevent movement of fluids into USDWs. RA1, with no explicit technical standards, requires generally that GS wells be constructed in a manner that will protect USDWs from endangerment; thus, the Agency assumes that given the uncertainty in how this standard would be implemented, wells could potentially be constructed without the appropriate materials and methods that specifically address the risks associated with $CO_2$ injection and risk under RA1 increases from baseline.

RA2, RA3, and RA4 would address risk by explicitly requiring that GS wells be constructed and cemented with casing, tubing, and packer that meet API or ASTM International standards and are compatible with $CO_2$. Each RA provides increasing specificity. RA 2 allows the Director's discretion to approve well materials and design. RA3 specifies the use of cemented surface casing (base of the lowermost USDW to surface) and long string casing (cemented from injection zone to surface) must be compatible with fluids with which they may be expected to come into contact. Additionally, RA3 also allows the use of horizontal well drilling techniques for GS wells which helps to reduce the number of injection wells potentially needed at a GS site thereby reducing the number of potential leakage pathways into USDWs. RA4 would require that the surface casing extend 100 feet below the lowermost USDW and the use of specialized, corrosion-resistant materials such as metal alloy casing, specialized tubing, and latex cements. These specific elements, which address the unique characteristics of $CO_2$ in the presence of water and are demonstrated to reduce the chances of compromising well integrity, are therefore expected to decrease risk relative to the baseline.

EPA assumes in the analysis that under RA1 and RA2 operators would inject below the lowermost USDW, except for in limited cases when a waiver of this depth requirement was approved, as discussed further below with regard to RA3. The explicit formal waiver application process and additional permit conditions that directly address the presence of USDWs above and below the injection zone will result in a minimal increase in risk for RAs 1-3 relative to the baseline.

RA4 would require that in all cases, operators inject below the lowermost USDW, as under the baseline scenario. This would apply in most cases to RA3, however, as for RA1 and RA2, owners and operators would have the option in limited circumstances to seek a waiver from this requirement to allow injection into non-USDW formations between USDWs in cases where there are deep USDWs and/or where injection into the lowermost USDW would result in impractical or technically infeasible well construction. The explicit formal waiver application process and additional permit conditions that directly address the presence of USDWs above and below the injection zone will result in a minimal increase in risk for RA3 relative to the baseline. In these limited circumstances owners and operators would be required to submit additional data and be subject to additional requirements above and beyond the RA3 requirements for wells injecting below the lowermost USDWs as added protection. By giving owners and operators the option of injecting above the lowermost USDW via the waiver process, there is an incremental risk increase relative to complete prohibition of the practice as under the baseline and RA4.

### 4.2.4 Injection Well Operation

Under current regulations, injection must be conducted such that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs. .

RA1 applies the performance standard that injection wells must be operated in a manner that protects USDWs from endangerment but does not explicitly limit injection pressure. Therefore, the Agency assumes that in a portion of the cases, appropriate injection pressure limitations may not be employed, suggesting an increase in risk for RA1 from the baseline. RA2 has similar requirements as the baseline but allows for higher injection pressure at the Director's discretion; to the extent that it is possible to allow pressures that increase the risk of fracture, RA2 may potentially increase risk relative to baseline.

RA3 and RA4 require that owners and operators limit injection pressure to less than the fracture pressure of the injection formation in any portion of the area defined by the anticipated pressure front; RA4 additionally considers the capillary entry pressure at any point in the lowermost portion of the confining zone. To the extent that these limitations reduce the chance of initiating new fractures or propagating existing fractures in the injection zone, they decrease risk relative to the baseline.

RA4 additionally requires that the depth be sufficient to retain the $CO_2$ in a supercritical state; this can help reduce potential MI concerns associated with phase changes and decreases risk relative to baseline.

RA3 and RA4 also require that injection wells are equipped with down-hole shut-off systems or other safety mechanisms, e.g., check valves, that engage if any critical operating

parameters are exceeded and describe the remedial actions that owners and operators must take if the devices engage. This requirement under RA3 allows for director's discretion unless wells are located in offshore territorial State waters[2] where they are required because EPA believes that devices besides down-hole shut-off systems, such as check valves, may provide equal protection in some instances and RA3 allows for their use, if approved by the Director, provided they offer an equal level of protection to USDWs as an automatic down-hole shut-off device. By not allowing the director to approve an alternative device in any case, RA4 offers the most protection, but possibly at an unnecessary cost in terms of the increased risk for damage to the wells during operation. The requirement for down-hole safety mechanisms under RA3 and RA4 can help prevent leaks in the well or fractures in the confining layer that may in turn result in fluid movement that endangers a USDW. They also help assure that problems within the well system are addressed immediately, decreasing risk relative to the baseline.

Additionally, RA4 allows the Director to require that an odorant or a tracer be introduced to the injected $CO_2$ to facilitate early detection of leaks or movement outside of the intended injection zone in order to prevent endangerment of USDWs. To the extent that odorants or tracers are detected and result in modifications to the injection operation or early actions, RA4 further decreases risk relative to baseline.

Overall, under RA3 and RA4, there is expected to be a decrease in risk relative to the baseline for injection well operation requirements.

### 4.2.5 Mechanical Integrity Testing

Under the baseline, GS well owners and operators will be required to demonstrate that wells have internal mechanical integrity (MI) (i.e., there is no significant leak in the casing, tubing, or packer) every five years. Additionally, owners and operators may be required to conduct biannual tracer surveys of the bottom-hole cement using a $CO_2$-soluble isotope, and pressure fall-off tests every five years.

The general performance based measure of RA1, to monitor wells in a manner and frequency that protects USDWs from endangerment allows for greater interpretation in setting permit conditions. In some cases, directors may specify mechanical integrity testing (MIT) types and frequencies that are less protective than baseline requirements. Therefore, under RA1 there is a potential increase in the relative risk to the baseline for MIT requirements.

RA2 does not specify a testing frequency; rather, it provides flexibility to permitting authorities to specify MIT methods and testing frequencies that are appropriate to the specific project. As such, the Agency assumes that Directors may choose a testing interval of more than 5 years which could potentially allow MI problems to go undetected for longer periods of time; therefore, RA2 potentially increases risk from baseline.

Under RA3 and RA4, owners and operators must demonstrate internal MI by continuously monitoring injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long string casing. Continuous monitoring can provide

[2] Requirements specific to ocean injection wells in the Federal outer continental shelf are to be proposed under a separate regulation by the Minerals Management Service, and are not included in the GS Rule.

almost immediate warning that there is a problem with the injection well's internal MI, which is one of the most significant concerns, given the corrosive nature of $CO_2$. This requirement would directly address the unique nature of $CO_2$ injection for GS and therefore is expected to decrease risk from baseline.

Under RA3 and RA4, owners and operators must demonstrate external MI using an approved tracer survey such as an oxygen-activation log or temperature or noise logs. The Director also has the discretion to require a casing inspection log to determine the presence or absence of any casing corrosion. The external MIT requirements in these RAs differ in their frequency: they must be performed at least annually in RA3 and twice annually in RA4.

The more specific MIT requirements and the greater frequency of testing in RA3 and RA4 decrease risk from the baseline by providing earlier indication of any MI problems, and potentially to a greater degree in RA4, given the shorter frequencies.

### 4.2.6 Testing, Monitoring, and Reporting

Under the baseline, owners and operators of GS wells would monitor the nature of injected fluids; conduct ground water monitoring within the AoR (at the Director's discretion); and report quarterly on these results and on the characteristics of injection fluids, injection pressure, flow rate, volume and annular pressure, and the results of MITs.

RA1 would leave the specific monitoring requirements to the discretion of the Director; potentially reducing the amount of monitoring performed relative to the baseline and thus would mitigate less risk than the baseline scenario.

Under RA2, owners and operators would monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics. Owners and operators would report annually on the characteristics of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, and on the results of MITs. Because ground water monitoring would not be performed under RA2, EPA assumes that this alternative would increase risk relative to baseline because it eliminates an opportunity to detect unacceptable movement of $CO_2$ or other fluids.

Under RA3, owners and operators would develop, implement, and periodically review a plan for conducting testing and monitoring that is tailored to the site. This RA includes additional monitoring, including injectate monitoring; corrosion monitoring of the well's tubular, mechanical and cement components; pressure fall-off testing; $CO_2$ plume and pressure front tracking; and ground water quality monitoring. Under RA3, owners and operators will report operating and monitoring results twice per year in operating reports, unless the monthly MIT or other periodic tests revealed operations were somehow compromised, in which case 24 hour notification is required. Because the required monitoring plan and these monitoring requirements are tailored to the risks associated with injection of large volumes of $CO_2$ and to the specific aspects of the site and operational conditions, RA3 is expected to mitigate more risk than the baseline requirements.

RA4 includes all of the monitoring requirements in RA3, with additional specificity on some elements. In addition to corrosion monitoring, owners and operators would need to

demonstrate compatibility of well materials to the injected $CO_2$. Owners and operators would perform a pressure fall-off test annually instead of every 5 years as with RA3. The ground water monitoring requirements are more specific than under RA3, requiring that the monitoring wells are constructed with corrosion-resistant materials. It requires that the surface air and soil gas monitoring regime include all artificial penetrations within the AoR and other sensitive areas, e.g., in buildings and manmade surface structures that are intended for human occupancy. Finally, under RA4, owners and operators would submit monitoring reports every month. With additional monitoring requirements that are tailored to the GS site and address the specific contamination concerns associated with GS, RA4 would also be expected to mitigate more risk than the baseline requirements.

### 4.2.7 Injection Well Plugging, Post-Injection Site Care (PISC), and Site Closure

At the conclusion of injection of $CO_2$ for GS, the injection well must be plugged in a way that ensures that it would not serve as a conduit for future fluid movement. Under the baseline, owners and operators would ensure that the well is in a state of static equilibrium, plug the well using approved methods, and tag and test all plugs. Owners and operators would also conduct post-injection monitoring to confirm that the $CO_2$ movement is limited to intended zones.

RA1 has no specific requirements with respect to plugging and post-injection monitoring and therefore increases risk relative to the baseline. RA2 includes some specific injection well plugging requirements, including ensuring that the well is in a state of static equilibrium, plugging the well using approved methods, and tagging and testing all plugs. This RA also would require owners and operators to conduct post-injection monitoring for 10 years per a Director-approved plan. The inclusion of specific PISC requirements that $CO_2$ movement be monitored following injection activities to ensure that it is limited to intended zones in RA2 would pose a decreased risk relative to the baseline.

RA3 and RA4 contain more specific requirements for well plugging and PISC and site closure. Both alternatives would require owners and operators to flush the well with a buffer fluid, determine bottom-hole reservoir pressure, perform a final external MIT, and plug the well in a manner using approved methods that will prevent the movement of fluid that may endanger USDWs. Additionally, these RAs require owners and operators to develop and implement a plan to conduct PISC monitoring, (which may include pressure monitoring; geophysical monitoring, if appropriate; and geochemical monitoring in and above the injection zone and the USDW) to confirm that $CO_2$ movement is limited to intended zones. The sole difference between the alternatives is the time frame: 50 years for RA3 (the Director has the discretion to shorten or lengthen timeframe based on data submitted as part of the permit application, or collected during PISC) and 100 years for RA4. Following the PISC monitoring, owners and operators would perform a non-endangerment demonstration to ensure that there is no threat to USDWs and that no further monitoring is necessary. At this point, closure of the site is authorized.

The requirements in RA3 and RA4 for PISC monitoring for extended time frames that are tailored to site-specific conditions and the operational history of the injection operation and a final non-endangerment demonstration are specific to the unique nature of GS and are estimated to mitigate more risk than under the baseline regulatory scenario.

### 4.2.8 Financial Responsibility

Under the baseline regulatory scenario, owners and operators must demonstrate that they have the resources necessary to plug and abandon the injection well through a performance bond, or other appropriate means.

RA1 does not have such a requirement, and to the extent that there would not be resources to plug the injection well at the end of injection activities, suggests an increase in risk relative to the baseline. RA2 would require the operator to provide through a performance bond, or other appropriate means, the resources necessary to plug the well; this is the same requirement as in the baseline; thus there is no change relative to baseline.

RA3 and RA4 require the operator to demonstrate and maintain financial responsibility for not only plugging the injection well, but also for all needed corrective action, emergency and remedial response, and PISC and closure. Owners and operators would need to adjust the cost estimates for these activities periodically to account for inflation and other conditions that may affect costs. RA3 and RA4 mitigate more risk relative to the baseline because they provide more assurance that funds will be available to pay for the necessary activities and also provide for funds to address additional protective activities, e.g., corrective action, PISC, and emergency and remedial response.

### 4.2.9 Emergency and Remedial Response

Emergency and remedial response plans outline the specific steps an operator would take in the event of evidence that injected fluids are endangering USDWs. Although injection well owners and operators are required to cease injection and take necessary actions if they discover evidence of USDW endangerment, the Class I non-hazardous regulations do not have a specific requirement to develop and implement such a plan; thus, the baseline is presumed to have no such requirement. RA1 and RA2 have no such requirements and are assumed to present no change in risk relative to the baseline.

RA3 and RA4 would require GS well owners and operators to develop and periodically review an emergency and remedial response plan that describes actions to be taken to address events that may cause an endangerment to a USDW during the construction, operation and PISC periods of a GS project. In the event that there is evidence that the $CO_2$ or pressure front is endangering USDWs, the operator would cease injection, take necessary steps to identify and characterize the extent of any release, and implement the emergency and remedial response plan. By providing a means to address a release of $CO_2$ or endangerment of USDWs, RA3 and RA4 decrease risk relative to the baseline. By following this site specific plan for this possible event, the steps that will be taken will prevent even greater damage and will facilitate prompt well repair if that is necessary.

### 4.2.10 Adaptive Regulatory Process

Under RA 3 and RA4, once the rule is final EPA will continue to collect and review all available information related to GS research to determine the need for modifications of the minimum Federal requirements for Class VI wells. Every six years, the Agency will collect and review data to determine if modifications to the requirements are necessary. By allowing for the

possible inclusion of added requirements (or modification of existing requirements) to ensure the safe injection and sequestering of $CO_2$, RA3 and RA4 would result in a decrease in risk relative to the baseline regulatory requirements. RA1 and RA2 does not explicitly specify the inclusion of periodic evaluation for Class VI wells, thus there would be no change in risk relative to the baseline.

### 4.2.11 Overall Estimate of Change in Risk

Sections 4.2.1 through 4.2.11 describe the change in the direction of risk based on consideration of each regulatory alternative 1 – 4 relative to the baseline regulatory requirements. These changes were assessed for each component category of the GS Rule and RAs. An overall assessment of the direction of risk change for each regulatory alternative as a whole relative to the baseline requires consideration of the relative importance of each component to the risk mitigation provided by the alternative.

As shown in Exhibit 4.1, EPA estimates that under RA1, risk will move from the baseline in the direction of increase for eight of the ten components assessed; no change in risk is estimated related to emergency and remedial response. Thus, EPA estimates an overall increase in risk relative to the baseline for RA1.

Under RA2, EPA estimates that risk will increase for four of the eleven programmatic components of the GS rule (geologic characterization, injection well operation, MIT, and monitoring); that it will decrease in three categories (AoR /corrective action, well construction, and well plugging/PISC); and that it will not change from the baseline relative to four categories (financial responsibility, emergency and remedial response, injection depth waivers, and the adaptive rulemaking process). Although this alternative generally has many of the same requirements as the baseline, RA2 allows the Director to exercise discretion to modify these requirements. This introduces the potential for some permit standards to be less stringent than under the baseline. However, given the importance of the AoR/corrective action and construction components (which decrease risk relative to the baseline), it is expected that the overall resulting change in risk will be a slight decrease in comparison to the baseline.

Both RA3 and RA4 uniformly decrease risk across all regulatory components, indicating an overall decrease in risk under both regulatory alternatives. This is primarily attributed to the additional specificity in each of these alternatives that are tailored to address the unique nature of GS. However, in many instances the requirements under RA4 are more prescriptive or specify better technologies than under RA3; this results in the potential for risk reduction to be greatest under RA4.

## 4.3 Ancillary Benefits

In addition to the direct benefits associated with the GS Rule, the Agency has identified potential benefits in the protections provided to affected entities that are not directly addressed under the authority of the UIC Program as prescribed under the SDWA, which is limited to protection of USDWs. These ancillary protections apply to categories such as human health and welfare, the atmosphere, ecological receptors, surface water, and the physical environment. Risk to these entities from GS is not well understood; however, to the extent that such risk exists, the GS Rule mitigates it by requiring measures to protect USDWs from contamination. These measures include prevention of fluid migration away from the storage formation and injection site and extensive monitoring both during operations and after injection has ceased. These ancillary benefits are summarized below and are described in greater detail in the *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide* (USEPA, 2010c).

*Human Health/Welfare*

By requiring owners and operators to employ measures to protect USDWs from endangerment, the GS Rule mitigates the risk of illness associated with ingestion of acidic or brackish water or water that may be contaminated by materials that are mobilized from the soil/rock matrix. These measures include monitoring requirements and appropriate operational thresholds that decrease the potential for large scale $CO_2$ leaks. As $CO_2$ is an asphyxiant, humans can experience adverse health effects at elevated $CO_2$ concentrations (Raschi et al., 1997), and extremely high concentrations (above 30 percent) can result in fatality. Although the likelihood of $CO_2$ release from a GS operation is not understood in quantified terms, the GS Rule mitigates this risk.

Cultural and recreational resources may also be preserved by the GS Rule. Requirements for geological characterization of the well site and monitoring of the movement of the $CO_2$ plume will help maintain the physical integrity of the project surface area by mitigating potential risk of uplift of the surface topography or induced seismicity. Ecological resources that are used as recreation resources, such as rivers and lakes, will also experience reduced risk of contamination as a result of the rule by confining the $CO_2$ and brine below USDWs. The GS Rule may also mitigate potential risk to forests and other flora by protecting it from the harmful effects of exposure to elevated $CO_2$ levels.

Contaminated ground and surface water could have effects on surface and subsurface economic resources. The site characterization and monitoring aspects of the GS Rule mitigate this risk by ensuring fluid isolation. This ancillary benefit to the rule extends to forestry, agricultural, and other surface industries, which could experience reduced yields and diminished utility of land if ground or surface water is contaminated by $CO_2$, brine, or mobilized contaminants. It also mitigates risk to subsurface resources such as oil and gas reservoirs, which could be affected by pressure from $CO_2$ plumes.

*Surface Water*

Through geologic siting and well construction standards that prevent fluid movement in the subsurface and monitoring standards that would provide early warning of leakage out of intended zones, the GS Rule mitigates potential risk of contamination of surface water from GS

operations. Specifically, the GS Rule mitigates the risk of water quality degradation that is associated with $CO_2$ contamination, including: increased salinity, increased acidity, and mobilization of metals and impurities. It also mitigates the risk that pressure from $CO_2$ injection will affect regional ground water flow, which could affect the availability of water in certain areas.

*Ecological Receptors*

By requiring measures to contain the $CO_2$ and preventing fluid movement away from the injection site and storage formation, the GS Rule helps to mitigate the risk that some animal species could experience negative health effects associated with $CO_2$ exposure. Acidification of surface water due to $CO_2$ contamination could kill species sensitive to changes in pH living in or consuming the water, and species that dwell in the soil may be especially vulnerable to the effects of contaminated surface water and soil. $CO_2$ would also lower carbonate levels in water which would significantly affect calcifying aquatic organisms, which could be unable to form shells in acidic water.

*Atmosphere*

The GS Rule's requirements that reduce the likelihood of $CO_2$ migrating to USDWs will mitigate the risk of sequestered $CO_2$ escaping to the atmosphere, helping to ensure that the benefits of reduced $CO_2$ emissions to the atmosphere with regard to climate change are maintained. The well plugging and PISC requirements in the GS Rule further reduce the potential for leakage of $CO_2$ into the atmosphere and ensure effective long-term storage.

Additionally, plants relying on a water source that is impacted by injected $CO_2$ may be intolerant of the pH change or high concentrations of $CO_2$, which can inhibit root respiration and hinder oxygen uptake and plant growth. In the case of $CO_2$ contamination of plant life, animal species depending on these plants would also suffer detrimental health effects. The extensive geologic siting process, well construction, and monitoring requirements associated with the GS Rule mitigate these potential risks by guarding against $CO_2$ leakage.

*Physical Environment*

Uplift and induced seismic activity as a result of subsurface pressure changes associated with injecting large volumes of $CO_2$ could have significant financial ramifications as well as negative effects on human health. Subsurface pressure changes that exceed a formation's geomechanical strength could cause fracturing or reactivate faults and increase the potential for the aforementioned effects. The GS Rule helps to mitigate this kind of risk through evaluation of subsurface geomechanics, the presence of transmissive faults and fractures, and the seismic history of the site; injection pressure limitations; and monitoring of the $CO_2$ plume and pressure changes.

*Social Cost of Carbon*

The GS rule has many requirements that help ensure that $CO_2$ is not being lost from GS sites to the atmosphere. They include pressure integrity requirements for injection wells, various types of $CO_2$ detection and monitoring requirements, remedial action requirements, and required

minimum criteria for GS sites. These requirements provide assurance that sequestered $CO_2$ remains underground, which in turn provide benefits in terms of avoided emissions from GS sites. In other words, if $CO_2$ leaked out of a given GS site, a net reduction in emissions would not be realized. Therefore, ensuring that sequestered $CO_2$ remains underground has a net benefit. The cost to society of $CO_2$ emissions (and thus the value of avoided emissions) can be measured in dollars using an emerging metric called the Social Cost of Carbon (SCC). The SCC estimates allow benefits from reduced emissions in any future year to be estimated by multiplying the change in emissions in that year by the SCC value appropriate for that year. SCC estimates represent the dollar value of a one-ton change in $CO_2$ emissions and reflect underlying assumptions about the growth of emissions and changes in socio-economic trajectories. In February 2010, an interagency working group published SCC estimates for use in regulatory impact analyses of government regulations.

The interagency group selected four $CO_2$ SCC estimates for use in regulatory analyses. For 2010, these estimates are $5, $21, $35, and $65 (in 2007 dollars). The first three estimates are based on the average SCC across models and socio-economic and emissions scenarios at the 5, 3, and 2.5 percent discount rates, respectively. The fourth value, which corresponds to the 95th percentile SCC estimate at a 3 percent discount rate, represents higher-than-expected impacts from temperature change further out in the tails of the SCC distribution. The central value is the average SCC across models at the 3 percent discount rate. For purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasized the importance and value of considering the full range. These SCC estimates also grow over time. For instance, the central value increases to $24 per ton of $CO_2$ in 2015 and $26 per ton of $CO_2$ in 2020.

Due to the fact that this final rule does not require owners or operators to mitigate climate impacts through geologic sequestration of $CO_2$, the benefits (which can be measured using SCC) associated with geologic sequestration may be better ascribed to regulations that require and/or provide incentives for geologic sequestration. However, without the requirements of the GS Rule, a regulatory framework would not be in place to help ensure that $CO_2$ is not being lost from GS sites to the atmosphere. Therefore, a small (but unquantified) portion of the benefits of those other regulations may be attributable to the GS Rule.

## 4.4 Uncertainty in Benefits Estimates

In the absence of data allowing a quantitative assessment of GS rule benefits, the assessment of relative risks (and associated benefit potential) posed by each alternative considered is subjective. The four regulatory alternatives considered in this analysis represent increasing levels of regulatory certainty that are assumed to correlate with relative risk. This assumption is based on the potential differences in interpretations that can be made when sole discretion is given to different permitting authorities. The interpretation of how this discretion will be utilized is the major driver of uncertainty within the relative risk estimates presented in this chapter. EPA's experience within the UIC Program suggests that in those areas where discretion is allowed there are distinct differences in interpretation among permitting authorities nationally. The magnitude and impact of such differences is difficult to predict for the GS rule, but EPA believes its general interpretation of a decrease in potential risks in correlation to decreasing regulatory discretion is justified.

# 5. Cost Analysis

## 5.1 Introduction

This chapter presents an estimate of the national costs of the Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide ($CO_2$) Geologic Sequestration (GS) Wells (the GS Rule), as well as a brief qualitative discussion comparing costs to the benefits anticipated to accrue as a result of the GS Rule. This national cost estimate, prepared by the United States Environmental Protection Agency (EPA), is a summation of costs to owners and operators of GS wells and to the permitting authorities for complying with and implementing the GS Rule requirements. To develop this estimate, EPA calculated the incremental cost for GS Rule components that expand current GS operating practices to mitigate the risks to underground sources of drinking water (USDWs) that are particular to injection of $CO_2$ for the purposes of long-term storage. The GS Rule defines a new class of injection well (Class VI), along with technical criteria that tailor the existing UIC Program regulatory framework to address the unique nature of $CO_2$ injection for long-term storage in anticipation of the eventual use of GS to reduce $CO_2$ emissions to the atmosphere. Technical components of the GS Rule include geologic site characterization; area of review (AoR) and corrective action; injection well construction; injection well operation; mechanical integrity testing (MIT); monitoring; well plugging, post-injection site care (PISC) and site closure; financial responsibility; and emergency and remedial response.

Although the national costs estimated in this Cost Analysis are representative of costs that EPA expects owners and operators and permitting authorities to incur under the GS Rule, assumptions were made to facilitate development of a reasonably simple, transparent model. The cost model elements and assumptions therefore may not correspond directly with all rule requirements; for example, the Cost Analysis makes assumptions about the number of monitoring wells to be constructed although, in reality, the owners and operators and Director will determine this requirement on a site specific basis. The GS Rule language for some components provides for discretion on the part of the UIC Program Director and for site specific variability, therefore EPA has predicted how the Directors will apply this latitude for the purpose of estimating costs. EPA considered the various hydrogeologic conditions that might prevail in baseline projects and the level of stringency in protective measures that Directors would perceive as necessary for measures that are less than prescriptive in the GS Rule.

The detailed descriptions and analyses presented in this chapter focus on the selected regulatory alternative (Regulatory Alternative 3, or RA3); however, assumptions and cost estimates for the baseline (RA 0) and the other three RAs considered (RAs 1, 2, and 4) are presented in the exhibits in this chapter. Incremental costs with respect to the baseline are shown for the selected RA as well as the other alternatives considered during the regulatory development process. In addition, some exhibits include cost elements that apply to at least one alternative but not to the selected alternative, RA3. Furthermore, some exhibits include costs that correspond to activities that the owners and operators will undertake under any regulatory scenario (i.e., lease of land or pore space) but are outside the authority of the Safe Drinking Water Act (SDWA) and therefore are not attributable to the GS Rule; these are included in estimates of total costs but not in the incremental rule costs.

Owner and operator costs are estimated based on the scale of $CO_2$ injection into the subsurface and the type of formation serving as a reservoir. At the time of this rulemaking, EPA anticipates the following types of GS projects will predominate in the near and predictable future: pilot-scale projects in saline reservoirs and large-scale projects in saline and oil and gas reservoirs. Permitting authority costs include a variety of implementation and oversight activities such as training, data system updates, primacy applications, permit reviews and approvals (including waiver application review), consultations, and report reviews (i.e., monitoring results), as well as all associated recordkeeping.

EPA estimated owner and operator costs for the technical rule components using equipment price lists and quotes, wage rates from government sources (e.g., Bureau of Labor Statistics (BLS)) and industry sources, stakeholder input, and information developed for similar analyses (e.g., the UIC Program Information Collection Request (ICR)). The national costs are estimated using a spreadsheet model specifically developed for the GS Rule. The main advantage to this modeling approach is that it effectively captures point estimates of all cost information and presents them in a transparent manner. This information forms the basis for examining impacts of the GS Rule on owners and operators of GS wells.

The remainder of this chapter is organized as follows:

- **Section 5.2** describes the general costing methodology and compliance assumptions used to estimate national costs for the GS Rule.
- **Section 5.3** describes the methodology for projecting costs over a 50-year period according to the GS Rule compliance schedule, estimating the present value of each cost, and annualizing each cost over this period.
- **Section 5.4** describes the methodology for developing costs for all rule components.
- **Section 5.5** presents consumer cost estimates.
- **Section 5.6** presents the total annualized costs for the GS Rule and compares them to estimates for the other regulatory alternatives considered.
- **Section 5.7** qualitatively compares the estimated costs for the GS Rule to the anticipated benefits.
- **Section 5.8** discusses other economic measures.
- **Section 5.9** presents a discussion of non-quantified costs and uncertainties in cost.

## 5.2 General Cost Assumptions and Methodology

The GS Rule Cost Model incorporates several data elements, including unit costs for each compliance activity, the baseline number of projects deploying or in operation during each year

of the 50-year period of analysis, labor rates (discussed in Section 5.2.1), and general and administrative (G&A) costs (Section 5.2.2).

The cost model comprises the following components: characteristic profiles for the five types of projects that represent the 29[1] projects of the cost analysis baseline; unit costs for each compliance activity; a site selection factor to account for the cost of geologic site characterization of sites that turn out to be unusable[2]; an ER Applicability factor to account for how costs apply differently to transitioning GS projects (projects converting from existing Class II enhanced recovery (ER) operations to long-term storage operations) compared to saline projects; an application factor[3] and a schedule specific to each RA for each compliance activity; calculation of the costs for each compliance activity in nondiscounted, present value, and annualized dollars; and summation of these costs by rule component and by cost type (one-time, capital, and operations and maintenance (O&M) expenditures).

The five project type profiles contain characteristics that define each project type represented in the 29 baseline projects, included in Appendix A to this Cost Analysis. Some of these characteristics vary by reservoir formation: the depth of the injection zone (IZ) and the primary containment formation are deepest in saline formations, and shallower in oil and gas reservoirs. Additionally, limited projects with an approved waiver to inject between USDWs are likely to be shallower than those with injection zones below the lowermost USDW. Other characteristics vary by the GS project scale: the injection period for all pilot-scale projects is assumed to be 4 years, and for large-scale saline projects is 40 years. The injection period for existing Class II ER projects that plans to transition to a Class VI project for the primary purpose of long-term storage is 10 years (after 20 years of Class II ER). The assumptions used in developing the GS Rule baseline are described in Chapter 3 (Baseline Analysis) of the Cost Analysis.

The model is based on an algorithm for each compliance activity, which multiplies the unit cost by certain variables from the project type profiles and by the factors appropriate for a given project type (RA application factor, site selection factor, enhanced recovery application factor) to produce a project level cost (as opposed to a rule level cost) for each compliance activity. Descriptions of the unit costs, application factors, and algorithms developed in this analysis are provided in Appendix B, and the detailed derivation and sources of the unit costs are presented in the *Geologic $CO_2$ Sequestration Technology and Cost Analysis* (EPA, 2010a).

The model then multiplies the project level cost for each compliance activity by the corresponding number of respondents for that cost type, project type, and year to produce an

[1] This number does not represent 29 specific projects, but rather a modeled probability of projects that in total adds up to 29. Due to the fractional probability of certain types of projects occurring at certain times, fractions of projects will be referred to thought this chapter.

[2] The site selection factor applies to only the geologic site characterization costs. For saline projects, the factor is 25%. This multiplies the geologic site characterization unit costs by four to account for the assumption that one out of four sites that are geologically characterized is determined to be suitable for GS. Put another way, an operator will on average have to characterize four sites to find one suitable one. For ER projects, the site selection factor is 100% (all sites chosen for GS using ER sites are assumed to be suitable sites).

[3] The application factor is a percentage between 0 and 100 percent that is EPA's best estimate of the percentage of owners and operators, or the extent to which all owners and operators, will engage in a given compliance activity; it takes into account those aspects of the rule that allow for Director discretion and site specific variability, as well as general trends in the methods or equipment used by the GS industry.

annual rule cost for each compliance activity in each of the 50 years in the analysis period. The model calculates these annual estimates in nondiscounted dollars and in present value and annualized dollars discounted at both 3 percent and 7 percent. The model then summarizes the GS Rule costs for these activities for the 50-year period of analysis by rule component and further by cost type: one-time, capital, and O&M expenditures.

Lastly, the model compares the baseline regulatory scenario (RA0) to each of the RAs (RA1 – RA4) to derive the incremental costs attributed to the GS Rule. The regulatory baseline, for the purpose of this analysis, consists of EPA estimates of the decisions regarding GS projects that permitting authorities as well as owners and operators would have made under current UIC Program regulations. EPA assumes that, absent a GS Rule, permitting authorities would issue permits with conditions that are similar in stringency to those for Class I industrial waste disposal wells. A review of permits issued to early pilot-scale projects indicates that this is the case. Current permits require that these projects have siting, construction, operating (i.e., injection below the lowermost USDW), and monitoring and testing requirements that match Class I requirements. Consistent with *UIC Program Guidance # 83* (EPA, 2007), some of these wells are classified as Class V experimental technology wells; however they have permit conditions that meet the requirements of Class I non-hazardous wells.

### 5.2.1 Labor Rates

For costing purposes, EPA estimated the labor needs and hourly labor rates for two occupations: geoscientists and mining and geological engineers (see Exhibit 5.1). EPA obtained the rates for geoscientists from the American Association of Petroleum Geologists' (AAPG's) 2008-2009 annual salary survey. Assuming 15-19 years of experience, the hourly rate is $67.02 (based on an annual salary of $139,400).[4] EPA obtained rates for mining and geological engineers from the Society for Petroleum Engineers (SPE) annual survey. For a reservoir engineer with 11-15 years of experience, the hourly rate is $69.14 (based on an annual salary of $143,800).[5] EPA multiplied these rates by a loading factor of 1.6, as suggested by EPA's 2005 *ICR Handbook*, to account for overhead and benefits. Thus, the loaded labor rate for geoscientists is $107.23, and the rate for engineers is $110.62.

For this analysis, EPA assumed that the average hourly labor rate for a State employee is $30.90, based on the BLS average hourly wage for workers in the life, physical, and social science occupations in 2008.[6] This rate was multiplied by 1.6 to get a loaded rate of $49.44. The base hourly labor rate for EPA Regions directly implementing the Class VI program in States without primacy is $31.34. This rate is based on Federal employee pay scales issued by the U.S. Office of Personnel and Management[7] (OPM) and was multiplied by 1.6 for a loaded rate of $50.14.

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[4] http://www. aapg. org/explorer/salarysurvey. cfm

[5] Society for Petroleum Engineers Annual Membership Salary Survey Highlight Report. Prepared by Western Management Group. September 2008. p. 12
http://www. spe. org/spe-site/spe/spe/career/salary_survey/08SalarySurveyHighlights. pdf

[6] Occupational Employment and Wages, 2008. Table 1. National employment and wage data from the Occupational Employment Statistics survey by occupation, May 2008. http://www. bls. gov/news. release/pdf/ocwage. pdf

[7] Salary Table 2008-GS, Incorporating the 2. 5 Percent General Schedule Increase, Effective 2008. Hourly/Overtime Rates by Grade and Step. Grade 12, Step 5. http://www. opm. gov/oca/08tables/html/gs_h. asp

In developing the permitting authority costs, EPA estimated that 32 of the 57 States, Territories, and Tribes that currently participate in the UIC Program will have primacy for Class VI wells. EPA based this estimate on the number of States with existing Class II programs because of the likelihood that oil and gas reservoirs will be used for the primary purpose of long-term storage once oil and gas production has ceased plus additional States for which GS projects are already planned or operating. Federal and Primacy Agency costs are provided in Section 5.4.11.

**Exhibit 5.1 Loaded Labor Rates by Standard Occupational Classification (SOC) and Government Schedule Codes- 2008$**

| Source | Occupation | Mean Hourly Labor Rate |
|---|---|---|
| AAPG | Geoscientist | $107.23 |
| SPE | Mining & Geological Engineers | $110.62 |
| OPM | Federal Employee, GS 12 - Step 5 | $50.14 |
| BLS | State employee, life, physical, and social sciences | $49.44 |

Source: GS Cost Model

### 5.2.2 General and Administrative Costs

There are G&A costs that will be required during the life of the project that are incurred in day to day operations for all owners and operators, such as the costs for computers, telephones, lighting, office supplies, and maintenance and periodic replacement of such items. EPA estimates that G&A costs for the electric power generation, mining, and petroleum industries are 20% on average for all costs; therefore, the cost model multiplies the subtotal for each rule component by 1.20 to derive a total that includes G&A. The annualized costs for owners and operators summarized by rule component and by cost type include G&A costs. Permitting authority costs associated with G&A are included in Agency and State labor rates; thus, the annualized State/Agency totals also include G&A.

## 5.3 Projecting and Discounting National Costs

Cost estimates must be expressed in common units across the period of analysis so they can be summed and annualized. For the GS Rule and each RA considered, some activities occur once, such as the initial characterization of the geologic formations of the project site. Other activities, such as injectate analysis reports, will occur periodically throughout each year, and still others, such as mechanical integrity tests of the well or AoR reevaluations, are assumed to occur annually or less frequently (depending on the RA) during operations.

Project level costs are projected over a 50-year instead of a 25-year time period, as is normally performed for EPA drinking water regulations. EPA elected to increase the analysis period to better reflect the lifecycle costs of GS projects. These costs are present value (PV) costs calculated using discount rates of 3 and 7 percent as recommended by Office of Management and Budget (OMB) guidance.[8] However, to make the analysis results more comparable to the majority of other SDWA rulemakings, the PV costs for the 50-year analysis are then annualized over just the first 25 years of that period.[9]

A summary of these adjustments is as follows:

- Project all nondiscounted project costs over a 50-year time horizon based on the schedule for each compliance activity.
- Calculate total present value rule costs using 3 and 7 percent discount rates.
- Annualize the rule costs over 25 years using the same discount rates.

Appendix C contains results from each step above for the selected alternative (RA3) and for RAs 0, 1, 2, and 4.

## 5.4 Derivation of Costs for Owners and Operators of GS Wells and the Permitting Authority

This section presents the methodology and unit costs used to derive project and rule level costs for owners and operators of GS wells and UIC Program Directors to perform the activities required by the GS Rule, and a brief summary of the compliance activities comprising each rule component. This section includes an administrative subsection (5.4.1) in addition to the technical components introduced in Chapters 1, 2, and 4 of this Cost Analysis, shown below in subsections 5.4.2 – 5.4.11. A detailed summary of the GS Rule (Class VI) regulatory requirements is provided in Chapter 2 by rule component.

[8] The choice of an appropriate discount rate is a complex and controversial issue among economists and policy makers. Therefore, EPA compares streams of future national level costs using two alternative discount rates, 3 and 7 percent. The underlying logic for each discount rate can be found in *Guidelines for Preparing Economic Analyses* (EPA, 2000).

[9] Annualizing 50 years of costs over just 25 years has the effect of making costs appear greater, but in this case most costs are actually incurred over the first 25 years so annualizing over that period avoids making costs appear artificially low.

5.4.1 Rule Implementation and Annual Administration

5.4.2 Geologic Site Characterization

5.4.3 Area of Review and Corrective Action

5.4.4 Injection Well Construction

5.4.5 Injection Well Operation

5.4.6 Mechanical Integrity Testing

5.4.7 Monitoring

5.4.8 Well Plugging and Post-Injection Site Care

5.4.9 Financial Responsibility

5.4.10 Emergency and Remedial Response Plans

5.4.11 Permitting Authority Costs

This chapter uses information presented in Chapter 3 as a starting point for analysis of owners and operators of GS wells that are subject to each rule component and associated compliance activities. Exhibit 5.2 presents data from the characteristic profiles of the five project types, which are referenced throughout this section, and summarizes the operating variables that drive costs for the baseline projects. For example, the cost associated with permit issuance is uniform for all formation types, but costs related to storage capacity, depth of injection interval, and storage efficiency are affected by the geology of the reservoir and containment formations.

## Exhibit 5.2 Project Characteristics By Formation Type and Size

| Characteristic | Type of Project | | | | |
|---|---|---|---|---|---|
| | Saline | | | Enhanced Recovery | |
| | Pilot | Large | Large Waivered | ER | ER Waivered |
| Depth to Top of Injection Interval (ft) | 7,900 | 7,900 | 4,400 | 5,700 | 3,312 |
| Depth to Bottom of Injection Interval (ft) | 8,500 | 8,500 | 5,000 | 5,800 | 3,412 |
| Metric tonnes capacity at 100% storage efficiency | 30,022,272 | 737,154,000 | 737,154,000 | 32,574,981 | 29,860,399 |
| Storage efficiency | 10.0% | 10.0% | 10.0% | 49.4% | 49.4% |
| Area of Review ($mi^2$) [4] | 0.9 | 23.3 | 23.8 | 8.4 | 8.2 |
| Total Number of wells in Area of Review | 5 | 116 | 119 | 167 | 165 |
| Injection Wells Required (total) | 3 | 4 | 4 | 17 | 16 |
| Tubing Diameter (inches) | 6 | 6 | 6 | 4 | 4 |
| Depth of Stratigraphic Tests (ft.) | 2,400 | 9,350 | 5,500 | 2,400 | 2,400 |
| Number of Monitoring Wells above Injection Zone[1] | 1.0 | 5.8 | 8.7 | 2.1 | 3.1 |
| Number of Monitoring Wells into Injection Zone[1] | 1.0 | 5.8 | 8.7 | 2.1 | 3.1 |
| Depth of Monitoring Wells[2] (feet) | 5,783 | 5,783 | 4,783 | 4,192 | 3,266 |
| Long-string Casing of Monitoring Wells (diam. inches) | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 |
| Injection Period (years)[3] | 4 | 40 | 40 | 10 | 10 |

Source: Appendix A

Notes:

(1) The number of monitoring wells per site varies according to the RA and the size of the project area assumed for a representative project. Shown are the required number of wells in the pro forma of each project type for the selected RA (RA3).

(2) Well depths shown represent the typical (mean) monitoring well depth. Shown are the figures for RA3. Under RA3 and RA4, one half of the monitoring wells would be drilled to the bottom of the injection zone, while the other monitoring wells for RA3 and RA4, and all monitoring wells for RA1 and RA2, would be drilled to a depth halfway between the bottom of the lowest USDW and the top of the containment formation.

(3) GS projects in oil and gas reservoirs are assumed to operate for 30 years: 20 years under the existing UIC class II well regulations while the site is still used primarily for oil/gas production, and for the remaining 10 years under class VI for the primary purpose of long-term storage. This cost analysis includes costs for ER projects beginning with their transition from production to GS, i.e., 20 years into the 30 year injection period.

(4) The Area of Review is the size of the area estimated to encompass the plume throughout the project lifecycle.

(5) Projects that receive approval of a waiver of the requirement to inject below the lowermost USDW have reduced depth and a higher number of monitoring wells; this information is provided in the pro forma sheets presented in Appendix A of this Cost Analysis.

Sections 5.4.1 – 5.4.10 give a brief overview and unit costs of the activities that comprise each rule component. Section 5.4.11 provides a description of the compliance activities and associated costs for permitting authorities. An important distinction to note about the figures presented in Section 5.4 is that they provide both total and incremental costs incurred by owners and operators and the permitting authority during GS projects. The incremental, or rule, costs are those costs incurred to comply with regulatory requirements beyond those currently practiced by owners and operators of GS wells under existing UIC regulations for Class I non-hazardous wells.

### 5.4.1 Rule Implementation and Annual Administration

All owners and operators of GS wells subject to the GS Rule will incur one-time costs that include time for staff to become familiar with GS Rule provisions and to train employees on these activities. Owners and operators of all 29 projects subject to the GS Rule will perform implementation activities. The labor rates presented in Section 5.2.1 are used along with estimates of labor hours to generate implementation costs for all owners and operators. Based on previous experience with rule implementation, EPA estimates that each owner and operator will require a total of 80 hours to read and understand the rule, and a total of 16 hours to train personnel. These costs are included in the cost for filing a permit application, included in this analysis in Injection Well Construction costs (see Section 5.4.4). Costs for enforcement of the GS Rule are not included in this analysis but are understood to be the same for the rule as in the baseline regulatory scenario, resulting in no additional incremental cost for the GS Rule.

### 5.4.2 Geologic Site Characterization

The primary purpose of geologic site characterization is to determine whether a site is suitable and safe for injection and sequestration. The characterization process includes site evaluation and tests to support permit applications. It also involves the development of a baseline for the conditions (pressure, temperature, $CO_2$ flux, etc.) in the AoR to allow long-term monitoring to be successful. Geologic site characterization is designed to provide the geologic and hydrologic data needed to design the subsurface infrastructure, develop reservoir models, and design a monitoring program.

Under the GS Rule, all owners and operators of GS wells subject to the GS Rule will perform geologic site characterization in Year 1 of the project (not all projects will start at the same time). It is assumed that not all sites characterized will be suitable for GS; therefore a site selection success factor has been applied to the geologic site characterization unit costs to account for this extra cost. For saline projects, the analysis assumes that one in four sites characterized will be suitable for deployment. For sites transitioning from existing Class II (primary purpose is ER) to Class VI (primary purpose is long-term storage), which are already characterized as suitable for ER in advance of any effort for the purpose of GS, this analysis assumes that all sites characterized for GS will be suitable. Exhibit 5.3 presents the owner and operator burden and costs for the baseline, the GS Rule, and each RA considered for Geologic Site Characterization unit costs. The detailed calculations used to develop unit costs are presented in Appendix C of the Cost Analysis.

# Exhibit 5.3 Owner and Operator Burden and Unit Cost Estimates for Geologic Site Characterization (2008$)

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project - Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Develop maps and cross sections of local geologic structure. | $107.23 | 60 | $6,434 | N/A | RA0 | $ 25,736 | $ 25,736 | $ 51,471 | $ - | $ - |
| | | | | | RA1 | $ 6,434 | $ 6,434 | $ 12,868 | $ - | $ - |
| | | | | | RA2 | $ 12,868 | $ 12,868 | $ 25,736 | $ - | $ - |
| | | | | | RA3 | $ 25,736 | $ 25,736 | $ 51,471 | $ - | $ - |
| | | | | | RA4 | $ 25,736 | $ 25,736 | $ 51,471 | $ - | $ - |
| Conduct 3D seismic survey to identify faults and fractures in primary and secondary containment units. | N/A | N/A | N/A | $104,000/ square mile | RA0 | $ 1,839,242 | $ 9,687,400 | $19,697,002 | $ 310,826 | $ 616,490 |
| | | | | | RA1 | $ 919,621 | $ 4,843,700 | $ 9,848,501 | $ 155,413 | $ 308,245 |
| | | | | | RA2 | $ 1,839,242 | $ 9,687,400 | $19,697,002 | $ 310,826 | $ 616,490 |
| | | | | | RA3 | $ 2,758,863 | $14,531,099 | $29,545,503 | $ 466,239 | $ 924,735 |
| | | | | | RA4 | $ 3,678,484 | $19,374,799 | $39,394,004 | $ 621,652 | $ 1,232,980 |
| Obtain and analyze seismic (earthquake) history. | $107.23 | 60 | $6,434 | N/A | RA0 | $ 19,302 | $ 19,302 | $ 38,604 | $ - | $ - |
| | | | | | RA1 | $ 6,434 | $ 6,434 | $ 12,868 | $ - | $ - |
| | | | | | RA2 | $ 12,868 | $ 12,868 | $ 25,736 | $ - | $ - |
| | | | | | RA3 | $ 25,736 | $ 25,736 | $ 51,471 | $ - | $ - |
| | | | | | RA4 | $ 25,736 | $ 25,736 | $ 51,471 | $ - | $ - |
| Remote (aerial) survey of land, land uses, structures etc. | N/A | N/A | N/A | $415/square mile $3,100/site | RA0 | $ 11,660 | $ 67,257 | $ 137,246 | $ 752 | $ 1,490 |
| | | | | | RA1 | $ 11,660 | $ 67,257 | $ 137,246 | $ 752 | $ 1,490 |
| | | | | | RA2 | $ 11,660 | $ 67,257 | $ 137,246 | $ 752 | $ 1,490 |
| | | | | | RA3 | $ 11,660 | $ 67,257 | $ 137,246 | $ 752 | $ 1,490 |
| | | | | | RA4 | $ 11,660 | $ 67,257 | $ 137,246 | $ 752 | $ 1,490 |
| Obtain data on area, thickness, capacity, porosity and permeability of receiving formations and confining systems. | $107.23 | 24 | $2,574 | N/A | RA0 | $ 10,294 | $ 10,294 | $ 20,589 | $ 1,287 | $ 2,574 |
| | | | | | RA1 | $ 10,294 | $ 10,294 | $ 20,589 | $ 1,287 | $ 2,574 |
| | | | | | RA2 | $ 10,294 | $ 10,294 | $ 20,589 | $ 1,287 | $ 2,574 |
| | | | | | RA3 | $ 10,294 | $ 10,294 | $ 20,589 | $ 1,287 | $ 2,574 |
| | | | | | RA4 | $ 10,294 | $ 10,294 | $ 20,589 | $ 1,287 | $ 2,574 |
| Obtain geomechanical information on fractures, stress, rock strength, in situ fluid pressures (from existing data and literature). | $107.23 | 120 | $12,868 | N/A | RA0 | $ 25,736 | $ 25,736 | $ 51,471 | $ 643 | $ 1,287 |
| | | | | | RA1 | $ 25,736 | $ 25,736 | $ 51,471 | $ 643 | $ 1,287 |
| | | | | | RA2 | $ 25,736 | $ 25,736 | $ 51,471 | $ 643 | $ 1,287 |
| | | | | | RA3 | $ 38,604 | $ 38,604 | $ 77,207 | $ 965 | $ 1,930 |
| | | | | | RA4 | $ 51,471 | $ 51,471 | $ 102,943 | $ 1,287 | $ 2,574 |
| Obtain geomechanical information on fractures, stress, rock strength, in situ fluid pressures (new cores and tests). | N/A | N/A | N/A | $78/ foot (depth) $3,100/core | RA0 | $ 205,800 | $ 747,900 | $ 895,200 | $ 51,450 | $ 102,900 |
| | | | | | RA1 | $ 205,800 | $ 747,900 | $ 895,200 | $ 51,450 | $ 102,900 |
| | | | | | RA2 | $ 205,800 | $ 747,900 | $ 895,200 | $ 51,450 | $ 102,900 |
| | | | | | RA3 | $ 411,600 | $ 1,495,800 | $ 1,790,400 | $ 102,900 | $ 205,800 |
| | | | | | RA4 | $ 823,200 | $ 2,991,600 | $ 3,580,800 | $ 205,800 | $ 411,600 |
| List names and depth of all potentially affected Underground Sources of Drinking Water (USDWs). | $107.23 | 24 | $2,574 | N/A | RA0 | $ 10,294 | $ 10,294 | $ 20,589 | $ 257 | $ 515 |
| | | | | | RA1 | $ 10,294 | $ 10,294 | $ 20,589 | $ 257 | $ 515 |
| | | | | | RA2 | $ 10,294 | $ 10,294 | $ 20,589 | $ 257 | $ 515 |
| | | | | | RA3 | $ 10,294 | $ 10,294 | $ 20,589 | $ 257 | $ 515 |
| | | | | | RA4 | $ 10,294 | $ 10,294 | $ 20,589 | $ 257 | $ 515 |
| Provide geochemical information and maps/cross section on subsurface aquifers. | $107.23 | 60 | $6,434 | N/A | RA0 | $ 12,868 | $ 12,868 | $ 51,471 | $ 1,608 | $ 6,434 |
| | | | | | RA1 | $ 6,434 | $ 6,434 | $ 25,736 | $ 804 | $ 3,217 |
| | | | | | RA2 | $ 6,434 | $ 6,434 | $ 25,736 | $ 804 | $ 3,217 |
| | | | | | RA3 | $ 25,736 | $ 25,736 | $ 102,943 | $ 3,217 | $ 12,868 |
| | | | | | RA4 | $ 25,736 | $ 25,736 | $ 102,943 | $ 3,217 | $ 12,868 |
| Provide information on water-rock-CO2 geochemistry and mineral reactions. | $107.23 | 240 | $25,736 | $10,300/ site | RA0 | $ 36,036 | $ 36,036 | $ 108,107 | $ 9,009 | $ 27,027 |
| | | | | | RA1 | $ 36,036 | $ 36,036 | $ 108,107 | $ 9,009 | $ 27,027 |
| | | | | | RA2 | $ 72,071 | $ 72,071 | $ 216,214 | $ 18,018 | $ 54,054 |
| | | | | | RA3 | $ 72,071 | $ 72,071 | $ 216,214 | $ 18,018 | $ 54,054 |
| | | | | | RA4 | $ 144,143 | $ 144,143 | $ 432,428 | $ 36,036 | $ 108,107 |
| Develop list of penetrations into injection zone within AoR (from well history data bases). | $107.23 | 12 hours/ square mile | $1,287/ square mile | N/A | RA0 | $ 4,879 | $ 119,805 | $ 245,255 | $ 1,075 | $ 2,119 |
| | | | | | RA1 | $ 4,879 | $ 119,805 | $ 245,255 | $ 1,075 | $ 2,119 |
| | | | | | RA2 | $ 4,879 | $ 119,805 | $ 245,255 | $ 1,075 | $ 2,119 |
| | | | | | RA3 | $ 4,879 | $ 119,805 | $ 245,255 | $ 1,075 | $ 2,119 |
| | | | | | RA4 | $ 4,879 | $ 119,805 | $ 245,255 | $ 1,075 | $ 2,119 |
| Develop list of penetrations into containment systems within AoR (from well history data bases). | $107.23 | 12 hours/ square mile | $1,287/ square mile | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ 4,879 | $ 119,805 | $ 245,255 | $ 1,075 | $ 2,119 |
| | | | | | RA4 | $ 4,879 | $ 119,805 | $ 245,255 | $ 1,075 | $ 2,119 |
| Develop list of water wells within AoR (from public data). | $107.23 | 36 hours/ square mile | $3,860/ square mile | N/A | RA0 | $ 3,659 | $ 89,853 | $ 183,941 | $ 806 | $ 1,589 |
| | | | | | RA1 | $ 3,659 | $ 89,853 | $ 183,941 | $ 806 | $ 1,589 |
| | | | | | RA2 | $ 3,659 | $ 89,853 | $ 183,941 | $ 806 | $ 1,589 |
| | | | | | RA3 | $ 3,659 | $ 89,853 | $ 183,941 | $ 806 | $ 1,589 |
| | | | | | RA4 | $ 14,638 | $ 359,414 | $ 735,766 | $ 3,224 | $ 6,357 |
| Prepare geologic characterization report demonstrating: suitability of receiving zone, storage capacity and injectivity, trapping mechanism free of nonsealing faults, competent confining system, etc. | $107.23 | 240 | $25,736 | N/A | RA0 | $ 102,943 | $ 102,943 | $ 257,357 | $ 25,736 | $ 64,339 |
| | | | | | RA1 | $ 102,943 | $ 102,943 | $ 257,357 | $ 25,736 | $ 64,339 |
| | | | | | RA2 | $ 102,943 | $ 102,943 | $ 257,357 | $ 25,736 | $ 64,339 |
| | | | | | RA3 | $ 102,943 | $ 102,943 | $ 257,357 | $ 25,736 | $ 64,339 |
| | | | | | RA4 | $ 102,943 | $ 102,943 | $ 257,357 | $ 25,736 | $ 64,339 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

#### 5.4.2.1 Annualized Costs for Geologic Site Characterization

Annualized costs for owners and operators under the geologic site characterization rule component for the baseline and RAs 1- 4 are presented in Exhibit 5.4.

**Exhibit 5.4 Owner and Operator Cost Estimates for Geologic Site Characterization – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate | |
|---|---|---|
| | 3% | 7% |
| Baseline | $ 6.70 | $ 8.35 |
| RA1 | $ 4.12 | $ 5.13 |
| Incremental RA1 | $ (2.58) | $ (3.22) |
| RA2 | $ 7.42 | $ 9.25 |
| Incremental RA2 | $ 0.72 | $ 0.90 |
| RA3 | $ 11.30 | $ 14.10 |
| Incremental RA3 | $ 4.61 | $ 5.75 |
| RA4 | $ 14.34 | $ 17.87 |
| Incremental RA4 | $ 7.64 | $ 9.52 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.3 Area of Review and Corrective Action

Owners and operators of GS wells will use computational models to determine, in three dimensions, the extent of the AoR. The models will account for the physical and chemical properties of all phases of the injected $CO_2$ and the associated pressure front and will be based on information collected on site during geologic site characterization and during development of estimates for operating conditions.

Owners and operators must identify all wells within the AoR that penetrate the injection zone or confining zone and determine which need to be addressed through appropriate corrective action. Old wells may provide conduits for the escape of injected $CO_2$ or formation fluids into overlying units or USDWs. In the case of saline formations, there may be few if any existing wellbores; however, in oil and gas reservoirs there will likely be many existing wellbores.

Corrective action on wells in the AoR may involve the removal of existing plugs and casing strings, and recompleting the well. This may involve the use of $CO_2$ resistant cements in portions of the well.

It is assumed that each well owner and operator will need to remediate 10 percent of old wells within the AoR. AoR costs will be incurred in Year 1 of each project, before the injection wells are put online, and at recurring intervals as the AoR is re-evaluated and potentially expanded or where phased corrective action is allowed. (The recurring cost for updating the AoR using computational models of $CO_2$ fluid flows is included in the ongoing costs for monitoring in Section 5.4.7). Exhibit 5.5 presents the owner and operator burden and costs for the baseline, the

GS Rule, and each RA considered for AoR and Corrective Action unit costs. The detailed calculations used to develop unit costs are presented in Appendix C of the Cost Analysis.

## Exhibit 5.5 Owner and Operator Burden and Unit Cost Estimates for AoR and Corrective Action (2008$)

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project - Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Simple fluid flow calculations to predict CO2 fluid flow. | $110.62 | 36 hours/site 12 hours/injection well | $3,982/ site + $1,327/ injection well | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ 3,982 | $ 4,646 | $ 4,646 | $ 13,275 | $ 12,611 |
| | | | | | RA2 | $ 3,982 | $ 4,646 | $ 4,646 | $ 13,275 | $ 12,611 |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Complex modeling of CO2 fluid flows and migration (reservoir simulations) over 100 years, and prepare AOR/Corrective Action plan. | $110.62 | 180 hours/site 24 hours/injection well | $19,912/ site + $2,655/ injection well | N/A | RA0 | $ 27,877 | $ 30,532 | $ 30,532 | $ 65,047 | $ 62,392 |
| | | | | | RA1 | $ 13,939 | $ 15,266 | $ 15,266 | $ 32,523 | $ 31,196 |
| | | | | | RA2 | $ 13,939 | $ 15,266 | $ 15,266 | $ 32,523 | $ 31,196 |
| | | | | | RA3 | $ 30,532 | $ 34,072 | $ 34,072 | $ 80,092 | $ 76,552 |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Complex modeling of CO2 fluid flows and migration (reservoir simulations) over 10,000 years, and prepare AOR/Corrective Action plan. | $110.62 | 180 hours/site 44 hours/injection well | $19,912/ site + $4,867/ injection well | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ 34,515 | $ 39,382 | $ 39,382 | $ 102,659 | $ 97,792 |
| Aerial search for old wells (artificial penetrations). This includes helicopter magnetic survey and follow-up ground survey. | N/A | N/A | N/A | $5,200/site $13,230/square mile | RA0 | $ 4,435 | $ 78,285 | $ 80,099 | $ 2,892 | $ 2,853 |
| | | | | | RA1 | $ 4,435 | $ 78,285 | $ 80,099 | $ 2,892 | $ 2,853 |
| | | | | | RA2 | $ 4,435 | $ 78,285 | $ 80,099 | $ 2,892 | $ 2,853 |
| | | | | | RA3 | $ 4,435 | $ 78,285 | $ 80,099 | $ 2,892 | $ 2,853 |
| | | | | | RA4 | $ 17,742 | $ 313,141 | $ 320,397 | $ 11,568 | $ 11,413 |
| Evaluate integrity of construction and record of completion and/or plugging of existing wells that penetrate containment system. | $110.62 | 24 hours/site 6 hours/well | $2,655/ site + $664/ well | N/A | RA0 | $ 3,203 | $ 18,023 | $ 18,387 | $ 9,126 | $ 9,001 |
| | | | | | RA1 | $ 3,203 | $ 18,023 | $ 18,387 | $ 9,126 | $ 9,001 |
| | | | | | RA2 | $ 3,203 | $ 18,023 | $ 18,387 | $ 9,126 | $ 9,001 |
| | | | | | RA3 | $ 3,203 | $ 18,023 | $ 18,387 | $ 9,126 | $ 9,001 |
| | | | | | RA4 | $ 3,203 | $ 18,023 | $ 18,387 | $ 9,126 | $ 9,001 |
| Evaluate integrity of construction and record of completion and/or plugging of existing shallow wells that pose a threat to USDWs. | $110.62 | 6 hours/well | $664/ well | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ 2,517 | $ 61,797 | $ 63,253 | $ 2,217 | $ 2,186 |
| Remediate old wells in AoR that pose a risk to USDWs. Use two cement plugs: one in producing formation and one for surface to bottom of USDWs, fill the remainder of the borehole with mud. | N/A | N/A | N/A | $56,100/oil or gas well $20,700/water well | RA0 | $ 19,879 | $ 488,097 | $ 499,599 | $ 877,823 | $ 865,507 |
| | | | | | RA1 | $ 19,879 | $ 488,097 | $ 499,599 | $ 877,823 | $ 865,507 |
| | | | | | RA2 | $ 19,879 | $ 488,097 | $ 499,599 | $ 877,823 | $ 865,507 |
| | | | | | RA3 | $ 19,879 | $ 488,097 | $ 499,599 | $ 877,823 | $ 865,507 |
| | | | | | RA4 | $ 19,879 | $ 488,097 | $ 499,599 | $ 877,823 | $ 865,507 |
| Remediate old wells in AoR that lack high quality cementing information. Use two cement plugs: one in producing formation and one for surface to bottom of USDWs, fill the remainder of the borehole with mud. | N/A | N/A | N/A | $56,100/oil or gas well $20,700/water well | RA0 | $ 7,455 | $ 183,036 | $ 374,699 | $ 329,184 | $ 649,130 |
| | | | | | RA1 | $ 7,455 | $ 183,036 | $ 374,699 | $ 329,184 | $ 649,130 |
| | | | | | RA2 | $ 7,455 | $ 183,036 | $ 374,699 | $ 329,184 | $ 649,130 |
| | | | | | RA3 | $ 14,909 | $ 366,073 | $ 749,398 | $ 658,367 | $ 1,298,260 |
| | | | | | RA4 | $ 14,909 | $ 366,073 | $ 749,398 | $ 658,367 | $ 1,298,260 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

### 5.4.3.1 Annualized Costs for Area of Review and Corrective Action

Annualized costs for owners and operators under the AoR and Corrective Action rule component for the baseline and RAs 1- 4 are presented in Exhibit 5.6.

**Exhibit 5.6 Owner and Operator Cost Estimates for AoR and Corrective Action – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate | |
|---|---|---|
| | 3% | 7% |
| **Baseline** | $ 1.09 | $ 0.98 |
| **RA1** | $ 1.14 | $ 1.04 |
| **Incremental RA1** | $ 0.06 | $ 0.05 |
| **RA2** | $ 1.14 | $ 1.04 |
| **Incremental RA2** | $ 0.06 | $ 0.05 |
| **RA3** | $ 1.46 | $ 1.32 |
| **Incremental RA3** | $ 0.38 | $ 0.34 |
| **RA4** | $ 1.55 | $ 1.46 |
| **Incremental RA4** | $ 0.46 | $ 0.47 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.4 Injection Well Construction

The technologies for drilling and equipping oil and gas wells and injection wells are well established. Advanced technologies are being developed and used across the country to enhance the production of oil and gas. These include horizontal drilling and multi-stage fracturing in shale formations, high tech stimulation and completion methods in tight gas reservoirs, and directional and deepwater wells offshore. Many ER projects using $CO_2$ are now active, especially in the Permian Basin of West Texas, and technologies have been developed to complete, produce, and maintain injection and production wells using this medium for long periods of time.

The design of a GS injection well is similar to that of a conventional gas injection well or a gas storage well, with the exception that much of the down-hole equipment must be upgraded for high pressure and corrosion resistance (IPCC, 2005). Upgrades include special casing and tubing, safety valves, cements, and blowout preventers. GS well owners and operators must construct their injection wells using materials and cements that are compatible with the $CO_2$ stream and/or other fluids with which they may come into contact. EPA assumes in this analysis that under RA1 and RA2 owners and operators would inject below the lowermost USDW, except for in limited cases when a waiver of this requirement was approved, as discussed further in Chapter 4, Section 4.2.4 with regard to RA3. Capital costs of injection well construction will be incurred by GS well owners and operators in Year 1 of each project, before injection begins.

Owners and operators of GS wells will need to obtain the right of way for surface use for injection and monitoring wells, and for subsurface or pore space use. While subsurface and pore space rights are an expense that is outside the authority of the Safe Drinking Water Act (SDWA) and therefore are not attributable to the GS Rule, they are included in the analysis because they are part of the total cost of a GS project, but in incremental (baseline minus RA), they are zero. These one-time costs will be incurred by GS well owners and operators prior to commencing the project, in Year 1 of the project.

Each owner and operator will have to apply for a UIC Program permit for their well. The permit application is complex and often includes several volumes of geologic data, maps and cross sections, schematics, monitoring and testing plans, and plans for well plugging, PISC, and

emergency and remedial response. The *Geologic $CO_2$ Sequestration Technology and Cost Analysis* (EPA, 2010a) describes all of the documentation included in the permit application. Facility construction permits will also be necessary for air emissions and water use incurred during construction. Also included in this item is the development of a corrosion control program for the well. Owners and operators are assumed to incur this cost in Year 1 of the project, before well construction begins.

Owners and operators will need to install monitoring equipment on each injection well to monitor injected volume, pressure, flow rate, and annulus pressure. Owners and operators will incur the costs of installing the monitoring equipment during Year 1 of the project, as wells are being constructed.

To meet the GS Rule requirements, owners and operators will be required to monitor ground water quality above the confining zone to verify isolation of the injection fluid. To this end, owners and operators will be required to construct one monitoring well above the injection zone per two square miles of AOR; for monitoring wells into the injection zone, the Agency assumes one monitoring well per four square miles. EPA assumes monitoring wells into the injection zone will also be used to sample above the injection zone (see Exhibit 5.2 for the required number of wells in the pro forma of each project type for the selected alternative, RA3). As is the case with injection wells, costs for monitoring wells are well established in the industry. Capital costs for monitoring wells will be incurred in Year 1 of each project, as the wells are being constructed.

Owners and operators will also need to build onsite pipelines to conduct the $CO_2$ from the distribution piping to the injection well. The basis for these costs is well understood because they are used in the oil and gas industry. It is estimated that the average saline formation GS project site will need to install 48 inch-miles of pipeline, and the average oil and gas reservoir project will need to install 59 inch-miles of pipeline. $CO_2$ pipeline costs are predominantly capital costs and will be incurred in Year 1 of each project. As with lease costs, the pipeline costs are outside the scope of the SDWA and are not attributable to the GS Rule; they are included in total project costs for completeness, but on an incremental (rule) basis they are zero.

Exhibit 5.7 presents the owner and operator burden and costs for the baseline, the GS Rule, and each RA considered for Injection Well Construction unit costs. The detailed calculations used to develop unit costs are presented in Appendix C of the Cost Analysis.

# Exhibit 5.7 Owner and Operator Burden and Unit Cost Estimates for Injection Well Construction (2008$)

| Compliance Activity | Labor Cost ($/hour) A | Labor Burden (hours) B | Labor Cost ($) C = B*A | Non-labor unit Cost[1] D | Regulatory Alternative E | Project Cost Pilot Project - Saline F | Project Cost Large Project - Saline G | Project Cost Large Waivered Project - Saline H | Project Cost Large Project - ER I | Project Cost Large Waivered Project - ER J |
|---|---|---|---|---|---|---|---|---|---|---|
| Conduct front-end engineering and design (general and injection wells), pre-op logging, sampling, and testing. Includes baseline pressure fall-off test. | N/A | N/A | N/A | $207,000/site $43,470/injection well | RA0 | $ 337,410 | $ 380,880 | $ 380,880 | $ 945,990 | $ 902,520 |
| | | | | | RA1 | $ 337,410 | $ 380,880 | $ 380,880 | $ 945,990 | $ 902,520 |
| | | | | | RA2 | $ 337,410 | $ 380,880 | $ 380,880 | $ 945,990 | $ 902,520 |
| | | | | | RA3 | $ 337,410 | $ 380,880 | $ 380,880 | $ 945,990 | $ 902,520 |
| | | | | | RA4 | $ 337,410 | $ 380,880 | $ 380,880 | $ 945,990 | $ 902,520 |
| Obtain rights-of-way for surface uses (equipment, injection wells). Pipeline rights-of-way are included in pipeline costs. Half of cost is legal fees for developer, other half is payment to landowner. | N/A | N/A | N/A | $20,700/injection well | RA0 | $ 62,100 | $ 82,800 | $ 82,800 | $ 175,950 | $ 165,600 |
| | | | | | RA1 | $ 62,100 | $ 82,800 | $ 82,800 | $ 175,950 | $ 165,600 |
| | | | | | RA2 | $ 62,100 | $ 82,800 | $ 82,800 | $ 175,950 | $ 165,600 |
| | | | | | RA3 | $ 62,100 | $ 82,800 | $ 82,800 | $ 175,950 | $ 165,600 |
| | | | | | RA4 | $ 62,100 | $ 82,800 | $ 82,800 | $ 175,950 | $ 165,600 |
| Lease rights for subsurface (pore space) use. Additional injection fees are included under O&M costs. | N/A | N/A | N/A | $52/acre | RA0 | $ 31,548 | $ 774,624 | $ 792,878 | $ 208,433 | $ 205,508 |
| | | | | | RA1 | $ 31,548 | $ 774,624 | $ 792,878 | $ 208,433 | $ 205,508 |
| | | | | | RA2 | $ 31,548 | $ 774,624 | $ 792,878 | $ 208,433 | $ 205,508 |
| | | | | | RA3 | $ 31,548 | $ 774,624 | $ 792,878 | $ 208,433 | $ 205,508 |
| | | | | | RA4 | $ 31,548 | $ 774,624 | $ 792,878 | $ 208,433 | $ 205,508 |
| Land use, air emissions, water discharge permits. | N/A | N/A | N/A | $103,400/site $20,700/sq. mile | RA0 | $ 123,023 | $ 585,213 | $ 596,566 | $ 276,259 | $ 273,834 |
| | | | | | RA1 | $ 123,023 | $ 585,213 | $ 596,566 | $ 276,259 | $ 273,834 |
| | | | | | RA2 | $ 123,023 | $ 585,213 | $ 596,566 | $ 276,259 | $ 273,834 |
| | | | | | RA3 | $ 123,023 | $ 585,213 | $ 596,566 | $ 276,259 | $ 273,834 |
| | | | | | RA4 | $ 123,023 | $ 585,213 | $ 596,566 | $ 276,259 | $ 273,834 |
| UIC permit filing, including preparation of attachments and required plans (see T&C Document for detail). | N/A | N/A | N/A | $10,400/site $6,000/injection well | RA0 | $ 39,020 | $ 45,020 | $ 135,060 | $ 75,020 | $ 219,060 |
| | | | | | RA1 | $ 39,020 | $ 45,020 | $ 135,060 | $ 75,020 | $ 219,060 |
| | | | | | RA2 | $ 39,020 | $ 45,020 | $ 135,060 | $ 75,020 | $ 219,060 |
| | | | | | RA3 | $ 39,020 | $ 45,020 | $ 135,060 | $ 75,020 | $ 219,060 |
| | | | | | RA4 | $ 39,020 | $ 45,020 | $ 135,060 | $ 75,020 | $ 219,060 |
| Standard injection well cost (from look up table). | N/A | N/A | N/A | $220-$290/foot (depth) down to 9,000 feet | RA0 | $ 7,189,653 | $ 9,586,205 | $ 4,647,171 | $ 2,406,404 | $ 1,332,265 |
| | | | | | RA1 | $ 7,189,653 | $ 9,586,205 | $ 4,647,171 | $ 2,406,404 | $ 1,332,265 |
| | | | | | RA2 | $ 7,189,653 | $ 9,586,205 | $ 4,647,171 | $ 2,406,404 | $ 1,332,265 |
| | | | | | RA3 | $ 7,189,653 | $ 9,586,205 | $ 4,647,171 | $ 2,406,404 | $ 1,332,265 |
| | | | | | RA4 | $ 7,189,653 | $ 9,586,205 | $ 4,647,171 | $ 2,406,404 | $ 1,332,265 |
| Corrosion resistant tubing. | N/A | N/A | N/A | $1.15/foot (length)-inch(diameter) | RA0 | $ 175,950 | $ 234,600 | $ 138,000 | $ 453,560 | $ 251,106 |
| | | | | | RA1 | $ 43,988 | $ 58,650 | $ 34,500 | $ 113,390 | $ 62,776 |
| | | | | | RA2 | $ 175,950 | $ 234,600 | $ 138,000 | $ 453,560 | $ 251,106 |
| | | | | | RA3 | $ 175,950 | $ 234,600 | $ 138,000 | $ 453,560 | $ 251,106 |
| | | | | | RA4 | $ 175,950 | $ 234,600 | $ 138,000 | $ 453,560 | $ 251,106 |
| Corrosion resistant casing: low alloy for RA2 and RA3, high alloy for RA4. | N/A | N/A | N/A | RA 2 & 3: $1.81/foot (length) - inch (diameter) | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ 481,913 | $ 642,550 | $ 814,500 | $ - | $ - |
| | | | | | RA3 | $ 481,913 | $ 642,550 | $ 814,500 | $ - | $ - |
| | | | | | RA4 | $ 718,875 | $ 958,500 | $ 1,215,000 | $ - | $ - |
| Cement well from surface through base of lowermost USDW and throughout injection zone. | N/A | N/A | N/A | $1.20/foot (length) - inch (diameter) | RA0 | $ 27,900 | $ 37,200 | $ 120,000 | $ - | $ - |
| | | | | | RA1 | $ 27,900 | $ 37,200 | $ 120,000 | $ - | $ - |
| | | | | | RA2 | $ 27,900 | $ 37,200 | $ 120,000 | $ - | $ - |
| | | | | | RA3 | $ 111,600 | $ 148,800 | $ 480,000 | $ - | $ - |
| | | | | | RA4 | $ 111,600 | $ 148,800 | $ 480,000 | $ - | $ - |
| Use CO2-resistant cement. | N/A | N/A | N/A | adds 25% to total cementing cost | RA0 | $ 6,975 | $ 9,300 | $ 30,000 | $ - | $ - |
| | | | | | RA1 | $ 6,975 | $ 9,300 | $ 30,000 | $ - | $ - |
| | | | | | RA2 | $ 27,900 | $ 37,200 | $ 120,000 | $ - | $ - |
| | | | | | RA3 | $ 27,900 | $ 37,200 | $ 120,000 | $ - | $ - |
| | | | | | RA4 | $ 27,900 | $ 37,200 | $ 120,000 | $ - | $ - |
| Injection pressure limited to 90% of fracture pressure of injection formation. | N/A | N/A | N/A | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Pumps. | N/A | N/A | N/A | $20,700/well site $1,550/HP of pump | RA0 | $ 512,071 | $ 1,187,640 | $ 1,187,640 | $ 1,316,124 | $ 1,215,072 |
| | | | | | RA1 | $ 512,071 | $ 1,187,640 | $ 1,187,640 | $ 1,316,124 | $ 1,215,072 |
| | | | | | RA2 | $ 512,071 | $ 1,187,640 | $ 1,187,640 | $ 1,316,124 | $ 1,215,072 |
| | | | | | RA3 | $ 512,071 | $ 1,187,640 | $ 1,187,640 | $ 1,316,124 | $ 1,215,072 |
| | | | | | RA4 | $ 512,071 | $ 1,187,640 | $ 1,187,640 | $ 1,316,124 | $ 1,215,072 |
| Wellhead and Control Equipment. | N/A | N/A | N/A | $520*(maximum tons per day injected/we | RA0 | $ 86,508 | $ 166,379 | $ 166,379 | $ 273,515 | $ 253,383 |
| | | | | | RA1 | $ 86,508 | $ 166,379 | $ 166,379 | $ 273,515 | $ 253,383 |
| | | | | | RA2 | $ 86,508 | $ 166,379 | $ 166,379 | $ 273,515 | $ 253,383 |
| | | | | | RA3 | $ 86,508 | $ 166,379 | $ 166,379 | $ 273,515 | $ 253,383 |
| | | | | | RA4 | $ 86,508 | $ 166,379 | $ 166,379 | $ 273,515 | $ 253,383 |

| Compliance Activity | Labor Cost ($/hour) A | Labor Burden (hours) B | Labor Cost ($) C = B*A | Non-labor unit Cost[1] D | Regulatory Alternative E | Project Cost Pilot Project - Saline F | Project Cost Large Project - Saline G | Project Cost Large Waivered Project - Saline H | Project Cost Large Project - ER I | Project Cost Large Waivered Project - ER J |
|---|---|---|---|---|---|---|---|---|---|---|
| All elements of pipeline costs. | N/A | N/A | N/A | $83,000/inch (diameter) - mile (length) | RA0 | $ 671,497 | $ 4,004,349 | $ 4,051,254 | $ 4,929,421 | $ 4,763,220 |
| | | | | | RA1 | $ 671,497 | $ 4,004,349 | $ 4,051,254 | $ 4,929,421 | $ 4,763,220 |
| | | | | | RA2 | $ 671,497 | $ 4,004,349 | $ 4,051,254 | $ 4,929,421 | $ 4,763,220 |
| | | | | | RA3 | $ 671,497 | $ 4,004,349 | $ 4,051,254 | $ 4,929,421 | $ 4,763,220 |
| | | | | | RA4 | $ 671,497 | $ 4,004,349 | $ 4,051,254 | $ 4,929,421 | $ 4,763,220 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

#### 5.4.4.1 Annualized Costs for Injection Well Construction

Annualized costs for owners and operators under the injection well construction component for the baseline and RAs 1- 4 are presented in Exhibit 5.8.

**Exhibit 5.8 Owner and Operator Cost Estimates for Injection Well Construction – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate 3% | Discount Rate 7% |
|---|---|---|
| **Baseline** | $ 16.17 | $ 17.04 |
| **RA1** | $ 16.53 | $ 17.45 |
| **Incremental RA1** | $ 0.36 | $ 0.40 |
| **RA2** | $ 17.28 | $ 18.29 |
| **Incremental RA2** | $ 1.12 | $ 1.25 |
| **RA3** | $ 17.37 | $ 18.40 |
| **Incremental RA3** | $ 1.20 | $ 1.36 |
| **RA4** | $ 16.89 | $ 17.95 |
| **Incremental RA4** | $ 0.72 | $ 0.91 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.5 Injection Well Operation

Owners and operators will incur annual costs for operating the injection and monitoring wells beginning in Year 2 of the project and will continue to incur these costs throughout the life of the injection period. Throughout injection, owners and operators will need to monitor injection rates, pressures, and volumes to assure that the well is operating within permitted parameters and does not fracture the injection zone. Other operating costs include regular maintenance of the well, electric costs for the pumps, land leases, insurance, providing reports to regulators, and contributions to a long-term monitoring, insurance, and remediation fund in proportion to the amount of $CO_2$ injected. EPA assumes that under RA1, RA2, and RA3, owners and operators would inject below the lowermost USDW, except for in limited cases when a waiver of this requirement was approved. This is discussed further in Chapter 4, Section 4.2.4.

At the director's discretion, owners and operators must also install down-hole devices (automatic shut-offs, check valves, or other, the selection of which is site specific and subject to the Director's discretion) that allow the well to be shut-in or injection stopped if conditions become unsafe or well integrity fails. Down-hole devices are required for all offshore wells located in State Territorial waters. Most down-hole monitoring costs will be capital costs and will be incurred in Year 1 of each project. This equipment, which is co-installed with monitoring devices, is accounted for under Section 5.4.7, Monitoring.

Exhibit 5.9 presents the owner and operator burden and costs for the baseline, the GS Rule, and each RA considered for Injection Well Operation unit costs. The detailed calculations used to develop unit costs are presented in Appendix C of the Cost Analysis.

# Exhibit 5.9 Owner and Operator Burden and Unit Cost Estimates for Well Operation (2008$)

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project - Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Develop a corrosion monitoring and prevention program. | $110.62 | 24 | $2,655 | N/A | RA0 | $ 664 | $ 664 | $ 664 | $ 664 | $ 664 |
| | | | | | RA1 | $ 664 | $ 664 | $ 664 | $ 664 | $ 664 |
| | | | | | RA2 | $ 1,327 | $ 1,327 | $ 1,327 | $ 1,327 | $ 1,327 |
| | | | | | RA3 | $ 2,655 | $ 2,655 | $ 2,655 | $ 2,655 | $ 2,655 |
| | | | | | RA4 | $ 2,655 | $ 2,655 | $ 2,655 | $ 2,655 | $ 2,655 |
| Corrosion monitoring: analysis of injectate stream and measurement of corrosion of well material coupons. | $110.62 | 6 hours/ well | $664 | $25/ well $300/sample | RA0 | $ 1,417 | $ 1,889 | $ 1,889 | $ 8,027 | $ 7,555 |
| | | | | | RA1 | $ 1,417 | $ 1,889 | $ 1,889 | $ 8,027 | $ 7,555 |
| | | | | | RA2 | $ 2,833 | $ 3,777 | $ 3,777 | $ 16,054 | $ 15,110 |
| | | | | | RA3 | $ 5,666 | $ 7,555 | $ 7,555 | $ 32,109 | $ 30,220 |
| | | | | | RA4 | $ 5,666 | $ 7,555 | $ 7,555 | $ 32,109 | $ 30,220 |
| Continuous measurement / monitoring equipment: injected volumes, pressure, flow rates and annulus pressure. | N/A | N/A | N/A | $15,500/well | RA0 | $ 46,500 | $ 62,000 | $ 62,000 | $ 263,500 | $ 248,000 |
| | | | | | RA1 | $ 46,500 | $ 62,000 | $ 62,000 | $ 263,500 | $ 248,000 |
| | | | | | RA2 | $ 46,500 | $ 62,000 | $ 62,000 | $ 263,500 | $ 248,000 |
| | | | | | RA3 | $ 46,500 | $ 62,000 | $ 62,000 | $ 263,500 | $ 248,000 |
| | | | | | RA4 | $ 46,500 | $ 62,000 | $ 62,000 | $ 263,500 | $ 248,000 |
| Equipment to add tracers. | N/A | N/A | N/A | $10,400/well | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ 7,800 | $ 10,400 | $ 10,400 | $ 44,200 | $ 41,600 |
| | | | | | RA3 | $ 7,800 | $ 10,400 | $ 10,400 | $ 44,200 | $ 41,600 |
| | | | | | RA4 | $ 15,600 | $ 20,800 | $ 20,800 | $ 88,400 | $ 83,200 |
| Electricity cost for pumps and equipment. | N/A | N/A | N/A | $0.066/KWh | RA0 | $ 142,666 | $ 350,296 | $ 350,296 | $ 305,713 | $ 280,236 |
| | | | | | RA1 | $ 142,666 | $ 350,296 | $ 350,296 | $ 305,713 | $ 280,236 |
| | | | | | RA2 | $ 142,666 | $ 350,296 | $ 350,296 | $ 305,713 | $ 280,236 |
| | | | | | RA3 | $ 142,666 | $ 350,296 | $ 350,296 | $ 305,713 | $ 280,236 |
| | | | | | RA4 | $ 142,666 | $ 350,296 | $ 350,296 | $ 305,713 | $ 280,236 |
| Injection well O&M. | N/A | N/A | N/A | $77,500/ injection well $3.10/foot (depth)/ injection well | RA0 | $ 311,550 | $ 415,400 | $ 372,000 | $ 1,623,160 | $ 1,409,224 |
| | | | | | RA1 | $ 311,550 | $ 415,400 | $ 372,000 | $ 1,623,160 | $ 1,409,224 |
| | | | | | RA2 | $ 311,550 | $ 415,400 | $ 372,000 | $ 1,623,160 | $ 1,409,224 |
| | | | | | RA3 | $ 311,550 | $ 415,400 | $ 372,000 | $ 1,623,160 | $ 1,409,224 |
| | | | | | RA4 | $ 311,550 | $ 415,400 | $ 372,000 | $ 1,623,160 | $ 1,409,224 |
| Pay rent for land use and rights-of-way. | N/A | N/A | N/A | $5.20/acre | RA0 | $ 3,155 | $ 77,462 | $ 79,288 | $ 27,791 | $ 27,401 |
| | | | | | RA1 | $ 3,155 | $ 77,462 | $ 79,288 | $ 27,791 | $ 27,401 |
| | | | | | RA2 | $ 3,155 | $ 77,462 | $ 79,288 | $ 27,791 | $ 27,401 |
| | | | | | RA3 | $ 3,155 | $ 77,462 | $ 79,288 | $ 27,791 | $ 27,401 |
| | | | | | RA4 | $ 3,155 | $ 77,462 | $ 79,288 | $ 27,791 | $ 27,401 |
| Pore space use costs. | N/A | N/A | N/A | $0.36/metric ton | RA0 | $ 270,200 | $ 663,439 | $ 663,439 | $ 579,001 | $ 530,751 |
| | | | | | RA1 | $ 270,200 | $ 663,439 | $ 663,439 | $ 579,001 | $ 530,751 |
| | | | | | RA2 | $ 270,200 | $ 663,439 | $ 663,439 | $ 579,001 | $ 530,751 |
| | | | | | RA3 | $ 270,200 | $ 663,439 | $ 663,439 | $ 579,001 | $ 530,751 |
| | | | | | RA4 | $ 270,200 | $ 663,439 | $ 663,439 | $ 579,001 | $ 530,751 |
| Property Taxes & Insurance. | N/A | N/A | N/A | $0.03/$1 CAPEX | RA0 | $ 265,328 | $ 502,925 | $ 384,826 | $ 296,776 | $ 253,389 |
| | | | | | RA1 | $ 265,174 | $ 541,926 | $ 454,403 | $ 294,084 | $ 259,864 |
| | | | | | RA2 | $ 284,452 | $ 567,630 | $ 485,012 | $ 305,856 | $ 266,988 |
| | | | | | RA3 | $ 328,058 | $ 765,830 | $ 638,672 | $ 347,748 | $ 306,313 |
| | | | | | RA4 | $ 335,824 | $ 777,616 | $ 652,994 | $ 350,045 | $ 308,521 |
| Tracers in injected fluid. | N/A | N/A | N/A | $0.05/ton of CO2 injected | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ 9,382 | $ 23,036 | $ 23,036 | $ 20,104 | $ 18,429 |
| | | | | | RA3 | $ 9,382 | $ 23,036 | $ 23,036 | $ 20,104 | $ 18,429 |
| | | | | | RA4 | $ 18,764 | $ 46,072 | $ 46,072 | $ 40,208 | $ 36,858 |
| Contribution to Long-term Monitoring, Insurance, and Remediation Fund. | N/A | N/A | N/A | $0.10/unit CO2 injected | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Repair and replace wells and equipment. | N/A | N/A | N/A | 1% of initial well and equipment cost | RA0 | $ 88,443 | $ 167,642 | $ 128,275 | $ 98,925 | $ 84,463 |
| | | | | | RA1 | $ 88,391 | $ 180,642 | $ 151,468 | $ 98,028 | $ 86,621 |
| | | | | | RA2 | $ 94,817 | $ 189,210 | $ 161,671 | $ 101,952 | $ 88,996 |
| | | | | | RA3 | $ 109,353 | $ 255,277 | $ 212,891 | $ 115,916 | $ 102,104 |
| | | | | | RA4 | $ 111,941 | $ 259,205 | $ 217,665 | $ 116,682 | $ 102,840 |
| General failure of containment at site: cost to remove and relocate the CO2. | N/A | N/A | N/A | 1.5% of total capital costs | RA0 | $ 33,166 | $ 6,287 | $ 4,810 | $ 14,839 | $ 12,669 |
| | | | | | RA1 | $ 33,147 | $ 6,774 | $ 5,680 | $ 14,704 | $ 12,993 |
| | | | | | RA2 | $ 33,779 | $ 6,741 | $ 5,760 | $ 14,528 | $ 12,682 |
| | | | | | RA3 | $ 32,806 | $ 7,658 | $ 6,387 | $ 13,910 | $ 12,253 |
| | | | | | RA4 | $ 31,484 | $ 7,290 | $ 6,122 | $ 13,127 | $ 11,570 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

#### 5.4.5.1 Annualized Costs for Injection Well Operation

Annualized costs for owners and operators under the well operation rule component for the baseline and RA 1- 4 are presented in Exhibit 5.10.

**Exhibit 5.10 Owner and Operator Cost Estimates for Well Operation – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate | |
|---|---|---|
| | 3% | 7% |
| **Baseline** | $ 41.81 | $ 28.23 |
| **RA1** | $ 44.62 | $ 30.17 |
| **Incremental RA1** | $ 2.81 | $ 1.94 |
| **RA2** | $ 45.87 | $ 31.03 |
| **Incremental RA2** | $ 4.06 | $ 2.80 |
| **RA3** | $ 50.27 | $ 34.16 |
| **Incremental RA3** | $ 8.46 | $ 5.92 |
| **RA4** | $ 48.51 | $ 32.99 |
| **Incremental RA4** | $ 6.70 | $ 4.75 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.6 Mechanical Integrity Testing

Under the GS Rule, owners and operators must demonstrate internal mechanical integrity by continuously monitoring injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long string casing. GS owners and operators will need to install monitoring equipment on each well to monitor these parameters. Costs for installing the monitoring equipment are accounted for under the injection well construction rule component, but because this equipment is used to monitor both well operation and integrity, equipment costs are accounted for under the monitoring rule component (see Section 5.4.7).

Owners and operators will demonstrate external mechanical integrity at least once per year using a tracer survey of the bottom-hole cement (using a $CO_2$ -soluble tracer or a suitable alternative method (e.g., Oxygen Activation Log (OAL)), a temperature or noise logs or other tests suitable to wells injecting liquid/super critical $CO_2$ fluids as approved by the permitting authority), or if required by the director a casing inspection log; or, another suitable method required and/or approved by the Director. Owners and operators will perform an initial external MIT after completion of well construction and prior to beginning operation in Year 2, and at least once per year throughout the life of the well. Exhibit 5.11 presents the owner and operator burden and costs for the baseline, the GS Rule, and each RA considered for MIT unit costs. The detailed calculations used to develop unit costs are presented in Appendix C of the Cost Analysis.

## Exhibit 5.11 Owner and Operator Burden and Unit Cost Estimates for Conducting MIT (2008$)

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project - Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Internal Mechanical integrity pressure test. | N/A | N/A | N/A | $2,070/ injection well | RA0 | $ 6,210 | $ 8,280 | $ 8,280 | $ 35,190 | $ 33,120 |
| | | | | | RA1 | $ 6,210 | $ 8,280 | $ 8,280 | $ 35,190 | $ 33,120 |
| | | | | | RA2 | $ 6,210 | $ 8,280 | $ 8,280 | $ 35,190 | $ 33,120 |
| | | | | | RA3 | $ 6,210 | $ 8,280 | $ 8,280 | $ 35,190 | $ 33,120 |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Casing inspection log. | N/A | N/A | N/A | $2,070/ injection well $4/foot (depth) | RA0 | $ - | $ - | $ - | $ - | $ 259,661 |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ 259,661 |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ 259,661 |
| | | | | | RA3 | $ 28,009 | $ 37,345 | $ 22,820 | $ 111,095 | $ 259,661 |
| | | | | | RA4 | $ 112,035 | $ 149,380 | $ 91,280 | $ 444,380 | $ 259,661 |
| Conduct a tracer survey of the bottom-hole cement using a CO2-soluble isotope. | N/A | N/A | N/A | $5,200/ injection well | RA0 | $ 3,900 | $ 5,200 | $ 7,800 | $ 22,100 | $ 31,200 |
| | | | | | RA1 | $ 3,900 | $ 5,200 | $ 7,800 | $ 22,100 | $ 31,200 |
| | | | | | RA2 | $ 3,900 | $ 5,200 | $ 7,800 | $ 22,100 | $ 31,200 |
| | | | | | RA3 | $ 7,800 | $ 10,400 | $ 15,600 | $ 44,200 | $ 62,400 |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Conduct a tracer survey of the bottom-hole cement using a CO2-soluble isotope. | N/A | N/A | N/A | $5,200/ injection well | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ 7,800 | $ 10,400 | $ 15,600 | $ 44,200 | $ 62,400 |
| External mechanical integrity tests to detect flow adjacent to well using temperature or noise log at least annually. | N/A | N/A | N/A | $2,070/ injection well $4/foot (depth) | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ 56,018 | $ 74,690 | $ 68,460 | $ 222,190 | $ 194,746 |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| External mechanical integrity tests to detect flow adjacent to well using temperature or noise log at least every 6 months. | N/A | N/A | N/A | $2,070/ injectionwell $4/foot (depth) | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ 56,018 | $ 74,690 | $ 68,460 | $ 222,190 | $ 194,746 |
| Conduct pressure fall-off test. | N/A | N/A | N/A | $2,070/ injection well | RA0 | $ 3,105 | $ 4,140 | $ 6,210 | $ 17,595 | $ 24,840 |
| | | | | | RA1 | $ 3,105 | $ 4,140 | $ 6,210 | $ 17,595 | $ 24,840 |
| | | | | | RA2 | $ 3,105 | $ 4,140 | $ 6,210 | $ 17,595 | $ 24,840 |
| | | | | | RA3 | $ 6,210 | $ 8,280 | $ 12,420 | $ 35,190 | $ 49,680 |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Conduct pressure fall-off test. | N/A | N/A | N/A | $2,070/ injection well | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ 6,210 | $ 8,280 | $ 8,280 | $ 35,190 | $ 33,120 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

### 5.4.6.1 Annualized Costs for Mechanical Integrity Testing

Annualized costs for owners and operators under the MIT rule component for the baseline and RA 1- 4 are presented in Exhibit 5.12.

**Exhibit 5.12 Owner and Operator Cost Estimates for MIT – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate | |
|---|---|---|
| | 3% | 7% |
| **Baseline** | $ 0.15 | $ 0.09 |
| **RA1** | $ 0.22 | $ 0.13 |
| **Incremental RA1** | $ 0.07 | $ 0.04 |
| **RA2** | $ 0.22 | $ 0.13 |
| **Incremental RA2** | $ 0.07 | $ 0.04 |
| **RA3** | $ 2.73 | $ 1.71 |
| **Incremental RA3** | $ 2.57 | $ 1.62 |
| **RA4** | $ 8.87 | $ 5.64 |
| **Incremental RA4** | $ 8.72 | $ 5.54 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.7 Monitoring

To ensure that the $CO_2$ remains safely sequestered in the injection zone and will not endanger USDWs, owners and operators will implement an extensive monitoring program. The monitoring program will be necessary to: supply the information that provides for an ongoing assessment of risk to USDWs, provide real time feedback for assessing parameters of the injection process, provide early warnings of failure, and verify that the $CO_2$ plume is behaving as expected.

Under the GS Rule, owners and operators must monitor the nature of the injectate and continuously monitor injection pressure, rates, and volumes, as well as the pressure on the annulus. Owners and operators must also monitor the well materials for signs of corrosion; this is addressed in Section 5.4.5 (Well Operation).

Owners and operators of GS wells must also track the position of the $CO_2$ plume and pressure front; this can be done by monitoring pressure changes above and within the confining zone, and, if appropriate, by using geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or other down-hole $CO_2$ detection tools). Owners and operators must also conduct a pressure fall-off test at least once every five years for RA0– RA3, and every six months for RA4 (the cost of this test is included with MIT costs in Section 5.4.6).

The GS Rule requires owners and operators to monitor ground water quality and geochemical changes above the confining zone using a network of monitoring wells and to track changes relative to baseline geochemical data. For oil and gas reservoirs, owners and operators will need to install U-tube sensors to detect oil movement in the bottom of the formation. Costs for installing the monitoring equipment and costs for the monitoring equipment itself are accounted for under this monitoring component. For the purposes of this analysis, monitoring equipment has been categorized into subsurface equipment (installed in wells) and surface equipment. Monitoring wells may have permanently installed down-hole equipment to measure pressure, temperature, resistivity, salinity, pH, pressure, and temperature. This equipment is used to monitor well operation and integrity. An additional cost for ER projects only is the installation and maintenance of a U-tube for sensing movement of oil away from the injection formation.

Some surface monitoring technologies require specific equipment to be installed. Most surface monitoring costs will be non-equipment or labor costs to conduct the surveys and analyze the data. Seismic monitoring and monitoring of $CO_2$ flux from the surface will require installation of monitoring equipment. Surface or near-surface monitoring equipment installation costs (if this monitoring is required by the Director) will be incurred in Year 1 of each project.

Additionally, the GS Rule requires that owners and operators update the AoR using computational (complex) modeling of the $CO_2$ fluid flow at minimum every 5 years. EPA also assumes that owners and operators under RA0-RA3 would develop a 100-year forecast and under the more stringent RA4 would develop a 10,000-year forecast. Owners and operators will also need to develop, review, and possibly revise their corrective action plans, monitoring and testing, well plugging, PISC and site closure, and emergency and remedial response plans as needed based on changes in the AoR.

Exhibit 5.13 presents the owner and operator burden and costs for the baseline, the GS Rule, and each RA considered for monitoring unit costs. The detailed calculations used to develop unit costs are presented in Appendix C of the Cost Analysis.

# Exhibit 5.13 Owner and Operator Burden and Unit Cost Estimates for Monitoring (2008$)

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project - Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Develop geochemical baseline for injection zones and confining zone. Assumes 4 samples per injection well. | N/A | N/A | N/A | $200/sample | RA 0 | $ 621 | $ 828 | $ 1,242 | $ 3,519 | $ 4,968 |
| | | | | | RA 1 | $ 621 | $ 828 | $ 1,242 | $ 3,519 | $ 4,968 |
| | | | | | RA 2 | $ 1,242 | $ 1,656 | $ 2,484 | $ 7,038 | $ 9,936 |
| | | | | | RA 3 | $ 2,484 | $ 3,312 | $ 4,968 | $ 14,076 | $ 19,872 |
| | | | | | RA 4 | $ 2,484 | $ 3,312 | $ 4,968 | $ 14,076 | $ 19,872 |
| Develop baseline of surface air CO2 flux for leakage monitoring. | N/A | N/A | N/A | $35,000/station | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Conduct front-end engineering and design for monitoring wells stopping above the confining zone. | N/A | N/A | N/A | $20,000/site $5,000/ monitoring well | RA 0 | $ 6,475 | $ 20,304 | $ 27,869 | $ 10,603 | $ 13,317 |
| | | | | | RA 1 | $ 12,950 | $ 40,609 | $ 55,738 | $ 21,206 | $ 26,634 |
| | | | | | RA 2 | $ 12,950 | $ 40,609 | $ 55,738 | $ 21,206 | $ 26,634 |
| | | | | | RA 3 | $ 25,900 | $ 50,959 | $ 66,088 | $ 31,556 | $ 36,984 |
| | | | | | RA 4 | $ 25,900 | $ 50,959 | $ 66,088 | $ 31,556 | $ 36,984 |
| Conduct front-end engineering and design for monitoring wells drilling into the injection zone. | N/A | N/A | N/A | $5,000/ monitoring well | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ 5,200 | $ 30,259 | $ 45,388 | $ 10,856 | $ 16,284 |
| | | | | | RA 4 | $ 5,200 | $ 30,259 | $ 45,388 | $ 10,856 | $ 16,284 |
| Obtain rights-of-way for surface uses (monitoring wells stopping above confining zone). | N/A | N/A | N/A | $10,000/ monitoring well | RA 0 | $ 2,600 | $ 30,259 | $ 45,388 | $ 10,856 | $ 16,284 |
| | | | | | RA 1 | $ 5,200 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA 2 | $ 5,200 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA 3 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA 4 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| Obtain rights-of-way for surface uses (monitoring wells drilling into injection zone). | N/A | N/A | N/A | $10,000/ monitoring well | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ 90,776 | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA 4 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| Obtain rights-of-way for surface uses (monitoring sites). | N/A | N/A | N/A | $5,000/air monitoring station site | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Check valve (Director discretion to require down-hole shut-off valve, but expected to be check valves in all but the most exceptional cases). | N/A | N/A | N/A | $15,000/site $2/foot (depth) | RA 0 | $ 375 | $ 500 | $ 500 | $ 2,125 | $ 2,000 |
| | | | | | RA 1 | $ 375 | $ 500 | $ 500 | $ 2,125 | $ 2,000 |
| | | | | | RA 2 | $ 375 | $ 500 | $ 500 | $ 2,125 | $ 2,000 |
| | | | | | RA 3 | $ 375 | $ 500 | $ 500 | $ 2,125 | $ 2,000 |
| | | | | | RA 4 | $ 1,500 | $ 2,000 | $ 2,000 | $ 8,500 | $ 8,000 |
| Standard monitoring well stopping above the confining zone (used look up table). Standard monitoring wells for ER projects stop below the | N/A | N/A | N/A | $100-$130/foot (depth) down to 9,000 feet | RA 0 | $ 121,625 | $ 1,415,472 | $ 2,241,164 | $ 218,156 | $ 308,552 |
| | | | | | RA 1 | $ 243,250 | $ 2,830,944 | $ 4,482,328 | $ 436,313 | $ 617,103 |
| | | | | | RA 2 | $ 243,250 | $ 2,830,944 | $ 4,482,328 | $ 436,313 | $ 617,103 |
| | | | | | RA 3 | $ 486,501 | $ 2,830,944 | $ 4,482,328 | $ 436,313 | $ 617,103 |
| | | | | | RA 4 | $ 486,501 | $ 2,830,944 | $ 4,482,328 | $ 436,313 | $ 617,103 |
| Standard monitoring well drilled into the injection zone (used look up table; applies to RA3-4 only). | N/A | N/A | N/A | $100-$130/foot (depth) down to 9,000 feet | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ 1,095,384 | $ 6,374,033 | $ 4,576,692 | $ 1,303,421 | $ 1,133,776 |
| | | | | | RA 4 | $ 1,095,384 | $ 6,374,033 | $ 4,576,692 | $ 1,303,421 | $ 1,133,776 |
| Pressure, temperature, and resistivity gauges and related equipment for monitoring wells stopping above the injection zone (application factor | N/A | N/A | N/A | $10,000/ monitoring well | RA 0 | $ 2,600 | $ 30,259 | $ 90,776 | $ 10,856 | $ 32,568 |
| | | | | | RA 1 | $ 5,200 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| | | | | | RA 2 | $ 5,200 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| | | | | | RA 3 | $ 10,400 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| | | | | | RA 4 | $ 10,400 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| Pressure, temperature, and resistivity gauges and related equipment for monitoring wells drilling into the injection zone (application factor reflects | N/A | N/A | N/A | $10,000/ monitoring well | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA 4 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| Salinity, CO2, tracer, etc. monitoring equipment for wells stopping above the injection zone (portion of equipment may be at surface such as for periodic in situ sampling using | N/A | N/A | N/A | $10,000/ monitoring well | RA 0 | $ 2,600 | $ 30,259 | $ 90,776 | $ 10,856 | $ 32,568 |
| | | | | | RA 1 | $ 5,200 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| | | | | | RA 2 | $ 5,200 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| | | | | | RA 3 | $ 10,400 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| | | | | | RA 4 | $ 10,400 | $ 60,518 | $ 181,553 | $ 21,712 | $ 65,135 |
| Salinity, CO2, tracer, etc. monitoring equipment for wells drilling into the injection zone (portion of equipment may be at surface such as for periodic in situ sampling using U-tubes; | N/A | N/A | N/A | $10,000/ monitoring well | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA 4 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project - Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| ER only. U-tube for sensing oil movement away from bottom of formation. Applies to 1 of every 4 monitoring wells drilled into the injection zone. | N/A | N/A | N/A | $30,000/ monitoring well $18/foot (depth) | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ 10,550 | $ 30,485 |
| | | | | | RA 2 | $ - | $ - | $ - | $ 10,550 | $ 30,485 |
| | | | | | RA 3 | $ - | $ - | $ - | $ 44,050 | $ 127,286 |
| | | | | | RA 4 | $ - | $ - | $ - | $ 44,050 | $ 127,286 |
| Develop plan and implement Eddy Covariance air monitoring. | $107.23 | 40 | $4,289 | $75,000/ monitoring site | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Develop plan and implement Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation. | N/A | N/A | N/A | $10,000/square mile | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Develop plan and implement LIDAR airborne survey to detect surface leaks. Works best where vegetation is sparse. Costs are for planning | N/A | N/A | N/A | $10,000/square mile | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Develop plan and implement soil zone monitoring. | $107.23 | 40 | $4,289 | $6,000/site | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Develop plan and implement vadose zone monitoring wells to sample gas above water table. | $107.23 | 40 | $4,289 | $8,000/site | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Develop a monitoring and testing plan, an emergency response plan, a post-injection site care and site closure plan and implement monitoring | $107.23 | 55 | $5,898 | $80,000/site | RA 0 | $ 21,072 | $ 21,072 | $ 31,608 | $ 21,072 | $ 31,608 |
| | | | | | RA 1 | $ 21,072 | $ 21,072 | $ 31,608 | $ 21,072 | $ 31,608 |
| | | | | | RA 2 | $ 42,145 | $ 42,145 | $ 63,217 | $ 42,145 | $ 63,217 |
| | | | | | RA 3 | $ 85,898 | $ 85,898 | $ 128,847 | $ 85,898 | $ 128,847 |
| | | | | | RA 4 | $ 85,898 | $ 85,898 | $ 128,847 | $ 85,898 | $ 128,847 |
| Conduct periodic monitoring of groundwater quality and geochemistry. | $110.62 | 0.5 hr/sample | $55.31/sample | $200/sample | RA 0 | $ 255 | $ 2,971 | $ 6,685 | $ 1,066 | $ 2,399 |
| | | | | | RA 1 | $ 511 | $ 3,227 | $ 7,260 | $ 1,321 | $ 2,973 |
| | | | | | RA 2 | $ 1,021 | $ 6,453 | $ 14,520 | $ 2,643 | $ 5,946 |
| | | | | | RA 3 | $ 2,042 | $ 11,885 | $ 26,742 | $ 4,264 | $ 9,594 |
| | | | | | RA 4 | $ 2,042 | $ 11,885 | $ 26,742 | $ 4,264 | $ 9,594 |
| Surface microseismic detection equipment: geophone arrays in monitoring wells. | N/A | N/A | N/A | $50,000/ monitoring site | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ 13,000 | $ 65,000 | $ 65,000 | $ 26,000 | $ 26,000 |
| Monitoring well O&M for wells stopping above the injection zone. | N/A | N/A | N/A | $25,000/ monitoring well $3/foot (depth) | RA 0 | $ 9,963 | $ 115,943 | $ 177,297 | $ 38,037 | $ 56,114 |
| | | | | | RA 1 | $ 19,925 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| | | | | | RA 2 | $ 19,925 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| | | | | | RA 3 | $ 39,850 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| | | | | | RA 4 | $ 39,850 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| Monitoring well O&M for wells drilling into the injection zone. | N/A | N/A | N/A | $25,000/ monitoring well $3/foot (depth) | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ 25,893 | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ 25,893 | $ - | $ - | $ - |
| | | | | | RA 3 | $ 51,785 | $ 301,336 | $ 357,301 | $ 91,445 | $ 113,984 |
| | | | | | RA 4 | $ 51,785 | $ 301,336 | $ 357,301 | $ 91,445 | $ 113,984 |
| ER only. U-tube O&M for 1 of 4 monitoring wells drilled into the injection zone. | $110.62 | 96 hours/ sample | $10,619.52/sample | $12,400/ sample | RA 0 | $ - | $ - | $ - | $ 2,500 | $ 5,000 |
| | | | | | RA 1 | $ - | $ - | $ - | $ 6,627 | $ 14,882 |
| | | | | | RA 2 | $ - | $ - | $ - | $ 6,627 | $ 14,882 |
| | | | | | RA 3 | $ - | $ - | $ - | $ 16,795 | $ 40,386 |
| | | | | | RA 4 | $ - | $ - | $ - | $ 16,795 | $ 40,386 |
| Annual cost of air and soil surveys: Eddy Covariance. | N/A | N/A | N/A | $10,000/ station | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |
| Annual cost of air and soil surveys: Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation. | N/A | N/A | N/A | $5,000/ site $6,250/ square mile | RA 0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA 4 | $ - | $ - | $ - | $ - | $ - |

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project - Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Annual cost of air and soil surveys: LIDAR airborne survey to detect surface leaks. Works best where vegetation is sparse. | N/A | N/A | N/A | $5,000/ site $6,250/ square mile | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Annual cost of air and soil surveys: soil zone monitoring. | N/A | N/A | N/A | $300/sample | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Annual cost of air and soil surveys: vadose zone monitoring wells to sample gas above water table. | N/A | N/A | N/A | $300/sample | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Annual cost of air and soil surveys: monitoring wells for gas samples from water table. | N/A | N/A | N/A | $1,200/sample | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Annual cost of passive seismic equipment. | N/A | N/A | N/A | $10,500/ station | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ 2,625 | $ 13,125 | $ 13,125 | $ 5,250 | $ 5,250 |
| Periodic seismic surveys: 3D. | N/A | N/A | N/A | $104,000/ square mile | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ 229,905 | $ 1,210,925 | $ 1,231,063 | $ 621,652 | $ 616,490 |
| | | | | | RA3 | $ 229,905 | $ 1,210,925 | $ 1,231,063 | $ 621,652 | $ 616,490 |
| | | | | | RA4 | $ 459,811 | $ 2,421,850 | $ 2,462,125 | $ 1,243,304 | $ 1,232,980 |
| Complex modeling of fluid flows and migration (reservoir simulations) over 100 years (RA0-3) or 10,000 years (RA4). Includes AoR and | $110.62 | 180 hours/ project site + 70 or 90 hours/well | $19,911.60 per project site + $9,956 per well | N/A | RA0 | $ 10,288 | $ 12,058 | $ 18,087 | $ 35,068 | $ 49,947 |
| | | | | | RA1 | $ 10,288 | $ 12,058 | $ 18,087 | $ 35,068 | $ 49,947 |
| | | | | | RA2 | $ 10,288 | $ 12,058 | $ 18,087 | $ 35,068 | $ 49,947 |
| | | | | | RA3 | $ 43,143 | $ 50,887 | $ 76,331 | $ 151,555 | $ 215,717 |
| | | | | | RA4 | $ 49,781 | $ 59,737 | $ 89,605 | $ 189,167 | $ 268,816 |
| Annual reports to regulators and recordkeeping for all data gathering activities. | $110.62 | 44 | $4,867 | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ 4,867 | $ 4,867 | $ 4,867 | $ 4,867 | $ 4,867 |
| | | | | | RA2 | $ 4,867 | $ 4,867 | $ 4,867 | $ 4,867 | $ 4,867 |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Semi-Annual (RA3) or quarterly (RA0) reports to regulators and recordkeeping for all data gathering activities. | $110.62 | 33 | $3,651 | N/A | RA0 | $ 1,079 | $ 1,079 | $ 1,079 | $ 1,079 | $ 1,079 |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ 3,651 | $ 3,651 | $ 3,651 | $ 3,651 | $ 3,651 |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |
| Monthly reports to regulators and recordkeeping for all data gathering activities and recordkeeping. | $110.62 | 11 | $1,217 | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ 1,217 | $ 1,217 | $ 1,217 | $ 1,217 | $ 1,217 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

### 5.4.7.1 Annualized Costs for Monitoring

Annualized costs for owners and operators under the monitoring rule component for the baseline and RAs 1- 4 are presented in Exhibit 5.14.

**Exhibit 5.14 Owner and Operator Cost Estimates for Monitoring – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate | |
|---|---|---|
| | 3% | 7% |
| **Baseline** | $ 3.39 | $ 2.90 |
| **RA1** | $ 7.07 | $ 6.08 |
| **Incremental RA1** | $ 3.67 | $ 3.19 |
| **RA2** | $ 11.43 | $ 8.96 |
| **Incremental RA2** | $ 8.03 | $ 6.07 |
| **RA3** | $ 21.95 | $ 18.65 |
| **Incremental RA3** | $ 18.56 | $ 15.76 |
| **RA4** | $ 24.43 | $ 20.06 |
| **Incremental RA4** | $ 21.04 | $ 17.16 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.8 Well Plugging and Post-injection Site Care

Following cessation of injection, owners and operators must plug injection wells to ensure that they do not become conduits for fluid movement. To do this, owners and operators will flush the well with a buffer fluid, perform a final external mechanical integrity test, and plug the well in a manner that will prevent the movement of fluid that may endanger USDWs. EPA assumes that injection wells will be plugged 1 year after completion of the injection phase.

Following injection, owners and operators must perform PISC to show the position of the $CO_2$ plume and pressure front and ensure that they will no longer pose an endangerment to USDWs. Under RAs 0-2, PISC must be performed for at least 10 years. For RA3 the default PISC period is 50 years; data submitted as part of the permit application, or collected during PISC and submitted to the Director can be used to request a shorter PISC period, subject to Director approval. Under RA4, PISC must be performed for 100 years (unless the Director approves a shorter time frame). However, this cost analysis considers only the costs that are incurred in the 50-year period of analysis from 2011 to 2060. PISC costs that are incurred in this period may include monitoring well O&M, seismic surveys, and air and soil tests, along with an updated demonstration of the financial capacity to plug the well.

PISC monitoring costs are generally assumed to be incurred at 5-year intervals from the year the injection is stopped until the end of the post-injection monitoring period (50 years for RA3), a portion of which is captured in the 50 year period of this Cost Analysis.

At the end of the PISC monitoring period, owners and operators must perform a non-endangerment demonstration showing that the $CO_2$ plume and pressure front have stabilized and that no additional monitoring is needed to assure that the project does not pose an endangerment to USDWs. If, based on this demonstration, the Director authorizes closure of the site, closure activities would include plugging the monitoring wells, removing surface equipment, and restoring the land.

Exhibit 5.15 presents the owner and operator burden and costs for the baseline, the GS Rule, and each RA considered for Well Plugging and PISC unit costs. Detailed calculations used to develop unit costs are presented in Appendix C of the Cost Analysis.

## Exhibit 5.15 Owner and Operator Burden and Unit Cost Estimates for Well Plugging and PISC (2008$)

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Flush wells with a buffer fluid before plugging. | N/A | N/A | N/A | $1,000/ injection well $0.085/foot (depth) | RA0 | $ 1,292 | $ 1,723 | $ 1,425 | $ 6,345 | $ 5,160 |
| | | | | | RA1 | $ 1,292 | $ 1,723 | $ 1,425 | $ 6,345 | $ 5,160 |
| | | | | | RA2 | $ 2,584 | $ 3,445 | $ 2,850 | $ 12,691 | $ 10,320 |
| | | | | | RA3 | $ 5,168 | $ 6,890 | $ 5,700 | $ 25,381 | $ 20,640 |
| | | | | | RA4 | $ 5,168 | $ 6,890 | $ 5,700 | $ 25,381 | $ 20,640 |
| Plug injection wells. Use two cement plugs: one in producing formation and one for surface to bottom of USDWs, fill the remainder of the borehole with | N/A | N/A | N/A | $24,900/ injection well | RA0 | $ 56,025 | $ 74,700 | $ 74,700 | $ 317,475 | $ 298,800 |
| | | | | | RA1 | $ 56,025 | $ 74,700 | $ 74,700 | $ 317,475 | $ 298,800 |
| | | | | | RA2 | $ 56,025 | $ 74,700 | $ 74,700 | $ 317,475 | $ 298,800 |
| | | | | | RA3 | $ 74,700 | $ 99,600 | $ 99,600 | $ 423,300 | $ 398,400 |
| | | | | | RA4 | $ 74,700 | $ 99,600 | $ 99,600 | $ 423,300 | $ 398,400 |
| Perform a mechanical integrity test prior to plugging to evaluate integrity of casing and cement to remain in ground. | N/A | N/A | N/A | $2,070/ injection well $4.15/foot (depth) | RA0 | $ 28,009 | $ 37,345 | $ 22,820 | $ 111,095 | $ 64,915 |
| | | | | | RA1 | $ 28,009 | $ 37,345 | $ 22,820 | $ 111,095 | $ 64,915 |
| | | | | | RA2 | $ 56,018 | $ 74,690 | $ 45,640 | $ 222,190 | $ 129,831 |
| | | | | | RA3 | $ 112,035 | $ 149,380 | $ 91,280 | $ 444,380 | $ 259,661 |
| | | | | | RA4 | $ 112,035 | $ 149,380 | $ 91,280 | $ 444,380 | $ 259,661 |
| Plug monitoring wells stopping above injection zone. Use one cement plug from the surface to the bottom of UDSWs, fill the remainder of the borehole with mud. | N/A | N/A | N/A | $12,400/ monitoring well | RA0 | $ 3,100 | $ 36,078 | $ 54,117 | $ 12,944 | $ 19,415 |
| | | | | | RA1 | $ 6,200 | $ 72,155 | $ 108,233 | $ 25,887 | $ 38,831 |
| | | | | | RA2 | $ 6,200 | $ 72,155 | $ 108,233 | $ 25,887 | $ 38,831 |
| | | | | | RA3 | $ 12,400 | $ 72,155 | $ 108,233 | $ 25,887 | $ 38,831 |
| | | | | | RA4 | $ 12,400 | $ 72,155 | $ 108,233 | $ 25,887 | $ 38,831 |
| Plug monitoring wells drilling into injection zone. Use one cement plug from the surface to the bottom of UDSWs, fill the remainder of the borehole with mud. | N/A | N/A | N/A | $12,400/ monitoring well | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ 12,400 | $ 72,155 | $ 108,233 | $ 25,887 | $ 38,831 |
| | | | | | RA4 | $ 12,400 | $ 72,155 | $ 108,233 | $ 25,887 | $ 38,831 |
| Remove surface equipment and structures; restore vegetation (injection wells). | N/A | N/A | N/A | $25,900/ injection well | RA0 | $ 77,700 | $ 103,600 | $ 103,600 | $ 440,300 | $ 414,400 |
| | | | | | RA1 | $ 77,700 | $ 103,600 | $ 103,600 | $ 440,300 | $ 414,400 |
| | | | | | RA2 | $ 77,700 | $ 103,600 | $ 103,600 | $ 440,300 | $ 414,400 |
| | | | | | RA3 | $ 77,700 | $ 103,600 | $ 103,600 | $ 440,300 | $ 414,400 |
| | | | | | RA4 | $ 77,700 | $ 103,600 | $ 103,600 | $ 440,300 | $ 414,400 |
| Remove surface equipment and structures; restore vegetation (monitoring well stopping above injection zone). | N/A | N/A | N/A | $10,400/ monitoring well $5,200/ monitoring station | RA0 | $ 2,600 | $ 30,259 | $ 45,388 | $ 10,856 | $ 16,284 |
| | | | | | RA1 | $ 5,200 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA2 | $ 5,200 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA3 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA4 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| Remove surface equipment and structures; restore vegetation (monitoring wells drilling into injection zone). | N/A | N/A | N/A | $10,400/ monitoring well | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| | | | | | RA4 | $ 10,400 | $ 60,518 | $ 90,776 | $ 21,712 | $ 32,568 |
| Document plugging and closure process (well plugging, post-injection plans, notification of intent to close, and post closure report). | $110.62 | 120 | $13,275 | N/A | RA0 | $ 6,637 | $ 6,637 | $ 6,637 | $ 6,637 | $ 6,637 |
| | | | | | RA1 | $ 6,637 | $ 6,637 | $ 6,637 | $ 6,637 | $ 6,637 |
| | | | | | RA2 | $ 6,637 | $ 6,637 | $ 6,637 | $ 6,637 | $ 6,637 |
| | | | | | RA3 | $ 13,275 | $ 13,275 | $ 13,275 | $ 13,275 | $ 13,275 |
| | | | | | RA4 | $ 13,275 | $ 13,275 | $ 13,275 | $ 13,275 | $ 13,275 |
| Post-closure O&M for monitoring wells stopping above injection zone (continues until plume has stabilized). | N/A | N/A | N/A | $25,900/ monitoring well $3.10/foot (depth)/ monitoring well | RA0 | $ 9,963 | $ 115,943 | $ 177,297 | $ 38,037 | $ 56,114 |
| | | | | | RA1 | $ 19,925 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| | | | | | RA2 | $ 19,925 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| | | | | | RA3 | $ 39,850 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| | | | | | RA4 | $ 39,850 | $ 231,887 | $ 354,595 | $ 76,075 | $ 112,228 |
| Post-closure O&M for monitoring wells drilling into injection zone (continues until plume has stabilized). | N/A | N/A | N/A | $25,000/ monitoring well $3/foot (depth)/ monitoring well | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ 51,785 | $ 301,336 | $ 357,301 | $ 91,445 | $ 113,984 |
| | | | | | RA4 | $ 51,785 | $ 301,336 | $ 357,301 | $ 91,445 | $ 113,984 |
| Post-injection air and soil surveys. | N/A | N/A | N/A | $10,400/ station | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA4 | $ - | $ - | $ - | $ - | $ - |

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Post-injection seismic survey. | N/A | N/A | N/A | $104,000/ square mile | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA3 | $ 229,905 | $ 1,210,925 | $ 1,231,063 | $ 621,652 | $ 616,490 |
| | | | | | RA4 | $ 459,811 | $ 2,421,850 | $ 2,462,125 | $ 1,243,304 | $ 1,232,980 |
| Periodic post-injection monitoring reports to regulators. | $110.62 | 40 | $4,425 | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ 4,425 | $ 4,425 | $ 4,425 | $ 4,425 | $ 4,425 |
| | | | | | RA3 | $ 4,425 | $ 4,425 | $ 4,425 | $ 4,425 | $ 4,425 |
| | | | | | RA4 | $ 4,425 | $ 4,425 | $ 4,425 | $ 4,425 | $ 4,425 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

### 5.4.8.1 Annualized Costs for Well Plugging and PISC

Annualized costs for owners and operators under the well-plugging and PISC component of the GS Rule for the baseline and RA 1- 4 are presented in Exhibit 5.16.

**Exhibit 5.16 Owner and Operator Cost Estimates for Well Plugging and PISC – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate 3% | Discount Rate 7% |
|---|---|---|
| **Baseline** | $ 0.59 | $ 0.24 |
| **RA1** | $ 0.86 | $ 0.33 |
| **Incremental RA1** | $ 0.27 | $ 0.09 |
| **RA2** | $ 0.91 | $ 0.35 |
| **Incremental RA2** | $ 0.33 | $ 0.12 |
| **RA3** | $ 2.76 | $ 1.01 |
| **Incremental RA3** | $ 2.17 | $ 0.77 |
| **RA4** | $ 3.26 | $ 1.18 |
| **Incremental RA4** | $ 2.67 | $ 0.95 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.9 Financial Responsibility

Under RA1 owners and operators have no requirement to demonstrate financial responsibility; under RA2 and the baseline (RA0) the owner and operator would provide financial assurance through a performance bond, or other appropriate means, of the resources necessary to plug the well.

RA3 and RA4 require the owners and operators to demonstrate and maintain financial responsibility for not only plugging the injection well, but also for all needed corrective action, emergency and remedial response, and PISC and closure (accounting for inflation). EPA assumes that owners and operators will post a performance bond and periodically re-evaluate the costs during the injection and PISC phases of the project. Financial responsibility following the injection phase is assumed to be demonstrated by posting a second bond when the wells are plugged in addition to the first bond posted prior to deployment. All GS well owners and operators are required to demonstrate financial responsibility. Exhibit 5.15 presents the owner and operator burden and costs for the baseline, the GS Rule, and each RA considered for Financial Responsibility unit costs.

### Exhibit 5.17 Owner and Operator Burden and Unit Cost Estimates for Financial Responsibility (2008$)

| Compliance Activity | Labor Cost ($/hour) | Labor Burden (hours) | Labor Cost ($) | Non-labor unit Cost[1] | Regulatory Alternative | Project Cost Pilot Project Saline | Project Cost Large Project - Saline | Project Cost Large Waivered Project - Saline | Project Cost Large Project - ER | Project Cost Large Waivered Project - ER |
|---|---|---|---|---|---|---|---|---|---|---|
| | A | B | C = B*A | D | E | F | G | H | I | J |
| Performance bond or demonstrate financial ability (accounting for inflation) to close site. | $110.62 | 8 | $885 | N/A | RA0 | $ 885 | $ 885 | $ 885 | $ 885 | $ 885 |
| | | | | | RA1 | $ 885 | $ 885 | $ 885 | $ 885 | $ 885 |
| | | | | | RA2 | $ 885 | $ 885 | $ 885 | $ 885 | $ 885 |
| | | | | | RA3 | $ 885 | $ 885 | $ 885 | $ 885 | $ 885 |
| | | | | | RA4 | $ 885 | $ 885 | $ 885 | $ 885 | $ 885 |
| Performance bond or demonstrate financial ability (accounting for inflation) for post-injection monitoring and remediation. | $110.62 | 4 | $442 | N/A | RA0 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA1 | $ - | $ - | $ - | $ - | $ - |
| | | | | | RA2 | $ 442 | $ 442 | $ 442 | $ 442 | $ 442 |
| | | | | | RA3 | $ 442 | $ 442 | $ 442 | $ 442 | $ 442 |
| | | | | | RA4 | $ 442 | $ 442 | $ 442 | $ 442 | $ 442 |

Source: GS Cost Model

**Notes:**

(1) Some cost components include labor burden that is not explicitly shown here.

**Sources:**

(A) Owner and operator labor cost from Exhibit 5.1.

(B), (D) Owner and operator burden and non-labor unit cost estimates reflect EPA's best professional judgment.

(E) As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(F)-(J) Nondiscounted Project level cost estimates from final GS Rule cost model, which are also presented in Appendix C of the Cost Analysis.

#### 5.4.9.1 Annualized Costs for Financial Responsibility

Annualized costs for owners and operators under the financial responsibility rule component for the baseline and RA 1- 4 are presented in Exhibit 5.18 (unlike the other annualized cost tables, Exhibit 5.18 is in 2008 dollars, not millions of 2008 dollars).

**Exhibit 5.18 Owner and Operator Cost Estimates for Financial Responsibility – Annualized Values Using a 3% and 7% Discount Rate (2008$)**

| Regulatory Alternative | Discount Rate | |
|---|---|---|
| | 3% | 7% |
| **Baseline** | $ 549 | $ 257 |
| **RA1** | $ 574 | $ 267 |
| **Incremental RA1** | $ 26 | $ 9 |
| **RA2** | $ 1,118 | $ 809 |
| **Incremental RA2** | $ 569 | $ 552 |
| **RA3** | $ 1,118 | $ 809 |
| **Incremental RA3** | $ 569 | $ 552 |
| **RA4** | $ 1,066 | $ 775 |
| **Incremental RA4** | $ 518 | $ 518 |

Source: Appendix C, Exhibit C.67/C.68

### 5.4.10 Emergency and Remedial Response Plans

GS well owners and operators must develop and implement an emergency and remedial response plan that describes actions to be taken to address movement of injection or formation fluids that may endanger USDWs. If there is evidence of potential endangerment of USDWs, the owner and operator will be required to cease injection, investigate and identify the release, and implement the emergency and remedial response plan. Some incidents could require replacement of well equipment, or remediation or removal of the $CO_2$. A percentage of the capital costs for well operation for each project is assumed to be contributed annually to a fund to account for the possible need for well remediation during operation.

Emergency and remedial response plans must be submitted as an attachment to the UIC Program permit application; as such these costs are included along with the permit application fee, as described in Section 5.4.4. Implementation of the plan is included in the cost items associated with well remediation, presented in Section 5.4.5. In addition, emergency and remedial response plans must be reviewed at least every five years, usually in association with AoR reevaluation. Costs for any necessary plan revision are included in the costs for AoR modeling in Section 5.4.3.

Annualized costs for owners and operators under the emergency and remedial response rule component for the baseline and RAs 1- 4 are included in the costs presented in Exhibits 5.6, 5.8, and 5.10.

### 5.4.11 Permitting Authority Costs

The following subsections provide a description of the permitting authority's oversight responsibilities for the GS Rule, organized by rule component. Exhibits 5.19 and 5.20 at the end of this section provide project level and annualized cost estimates for the permitting authority, respectively.

#### 5.4.11.1 Rule Implementation and Annual Administration

The permitting authority will incur administrative costs while implementing the GS Rule. These implementation costs are not directly required by specific provisions of GS Rule RAs but will be necessary for the permitting authority to ensure that the provisions of the GS Rule are properly carried out. The permitting authority will need to allocate time for their staff to establish and then maintain the programs necessary to comply with the GS Rule, including developing and/or modifying data management systems to track new required owner and operator reports to the permitting authority. Permitting authority staff at the State level will need to prepare primacy applications, which will be reviewed and approved by EPA. To manage data submitted by owners and operators, the permitting authority will also need to modify or develop data management systems. Finally, the permitting authority will need to provide technical assistance when owners and operators request help in implementing the GS Rule.

In addition to these one-time costs, the permitting authority will need to expend resources for ongoing administrative activities. On an annual basis, the permitting authority will provide technical assistance to well owners and operators and to their own staff as needed. Exhibit 5.19 lists these annual activities with their respective costs and burden.

#### 5.4.11.2 Geologic Site Characterization

The permitting authority will incur costs associated with reviewing geological data submitted by owners and operators to determine whether a proposed site is suitable for injection of large volumes of $CO_2$, such as maps and cross sections, geomechanical data, structural data, and seismic data. The permitting authority will review the owners and operators' site data beginning in Year 1 of the project.

#### 5.4.11.3 Area of Review and Corrective Action

The permitting authority costs associated with AoR and Corrective Action requirements include review of the owner and operator's proposed AoR and corrective action, which will be submitted in compliance with §146.84. The permitting authority will review one plan per GS site as they are received from owners and operators during the compliance period. The permitting authority will also review owner- and operator-submitted AoR modeling results and the status of corrective action in Year 1 and the AoR reevaluations and modified AoR and corrective action plans that owners and operators periodically submit over the course of the injection project.

#### 5.4.11.4 Injection Well Construction

Permitting authority activities associated with the well construction requirements of the GS Rule include review of owner- and operator-submitted construction schematics and procedures to assure that the injection well is properly designed to withstand injection of large volumes of $CO_2$.

As they review information on the geology of the site, the AoR, and construction procedures described above, the permitting authority will also review the other components of the permit application, including proposed monitoring plans, contingency plans, well plugging and PISC and site closure plans, and financial responsibility information. Additionally, in limited

cases, the permitting authority will also need to review applications for waivers that allow a project to inject above the lowermost USDW. In the case of States with primacy, such waivers will be reviewed at both the State and Federal level.

This cost analysis assumes that the permitting authority will review permit applications and associated materials in Year 1 of the project, and for some cost items (e.g., AoR evaluations and financial responsibility determinations) will review updates to the material periodically, or in specific project phases such as prior to plugging of the well for updated PISC and site closure plans.

#### 5.4.11.5 Injection Well Operation

The permitting authority will not incur any cost or burden associated with operation of injection wells.

#### 5.4.11.6 Mechanical Integrity Testing

At the Director's discretion, permitting authorities may visit the project site and witness the MITs. (The burden associated with reviewing MIT reports is captured under monitoring, below).

#### 5.4.11.7 Monitoring

EPA assumes that the permitting authority will incur burden associated with reviewing the annual, semi-annual, quarterly, or monthly monitoring reports submitted by well owners and operators, including injectate monitoring results, plume tracking data, ground water monitoring, MIT results, or other testing performed since the last report. Although reports may occur at different frequencies, the cost of reviewing them is considered on an annual basis. The permitting authority will review monitoring reports beginning in Year 2 of each project.

#### 5.4.11.8 Well Plugging and PISC

Permitting authority costs related to well plugging and PISC requirements include review and approval of the initial plans submitted with permit applications (which are estimated to occur in Year 1) and reviewing periodic updates to plans (which will occur periodically throughout the injection phase).

Permitting authorities will also review owners and operators' notification of intent to plug their wells and final updates to the closure plan; and reports documenting the well plugging process. The permitting authority may, at its discretion, witness the well plugging process or post-plugging MITs. This Cost Analysis does not include costs for this discretionary item.

During the PISC period, the permitting authority will incur costs related to review of post-injection monitoring reports. Permitting authorities will also review non-endangerment demonstrations following post-injection monitoring; this analysis includes such costs only as incurred within the 50-year period of analysis.

#### 5.4.11.9 Financial Responsibility

The permitting authority must review the financial assurance demonstrations provided by GS well owners and operators with their permit applications and any updated estimates submitted.

#### 5.4.11.10 Emergency and Remedial Response Plans

The permitting authority will review emergency and remedial response plans submitted by owners and operators along with other attachments to the permit application, which is included in the costs for reviewing permit applications. In addition, the permitting authority may need to respond to incidences where there is evidence of $CO_2$ leakage or other endangerment to USDWs; this cost incurrence is subject to a high degree of uncertainty and is not included in this analysis.

# Exhibit 5.19 Permitting Authority Burden and Unit Cost Estimates (2008$)

| Compliance Activity | State Labor Cost ($/hour) A | Federal Labor Cost ($/hour) B | Regulatory Alternative C | One-time labor burden (hrs) D | State Cost E=A*C*0.56 | Federal Cost F=B*C*0.44 | Weighted Project Cost[2] G=E+F |
|---|---|---|---|---|---|---|---|
| Administration (Staff Training, Rule Implementation). | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 12 | $ 593 | $ - | $ 593 |
| | | | RA2 | 12 | $ 593 | $ - | $ 593 |
| | | | RA3 | 12 | $ 593 | $ - | $ 593 |
| | | | RA4 | 12 | $ 593 | $ - | $ 593 |
| Federal Systems Updates. | $49.44 | $50.14 | RA0 | 4160 | $ - | $ 208,599 | $ 208,599 |
| | | | RA1 | 4160 | $ - | $ 208,599 | $ 208,599 |
| | | | RA2 | 4160 | $ - | $ 208,599 | $ 208,599 |
| | | | RA3 | 4160 | $ - | $ 208,599 | $ 208,599 |
| | | | RA4 | 4160 | $ - | $ 208,599 | $ 208,599 |
| Review information required in general UIC permit (Includes initial review of closure and post-closure plans). | $49.44 | $50.14 | RA0 | 40 | $ 1,110 | $ 880 | $ 1,990 |
| | | | RA1 | 40 | $ 1,110 | $ 880 | $ 1,990 |
| | | | RA2 | 40 | $ 1,110 | $ 880 | $ 1,990 |
| | | | RA3 | 40 | $ 1,110 | $ 880 | $ 1,990 |
| | | | RA4 | 40 | $ 1,110 | $ 880 | $ 1,990 |
| Permitting Authority: review waiver applications. | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 80 | $ 2,220 | $ 1,759 | $ 3,980 |
| | | | RA2 | 80 | $ 2,220 | $ 1,759 | $ 3,980 |
| | | | RA3 | 80 | $ 2,220 | $ 1,759 | $ 3,980 |
| | | | RA4 | 0 | $ - | $ - | $ - |
| Federal level: review waiver applications for those originally reviewed by State/Tribe/Territory having primacy. | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 80 | $ - | $ 2,252 | $ 2,252 |
| | | | RA2 | 80 | $ - | $ 2,252 | $ 2,252 |
| | | | RA3 | 80 | $ - | $ 2,252 | $ 2,252 |
| | | | RA4 | 0 | $ - | $ - | $ - |
| Review financial assurance of capacity to properly close, plug, and abandon well. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review financial assurance of capacity to provide post-closure care. | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 0 | $ - | $ - | $ - |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Second review of proposed closure plan required by §146.92(b). | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Second review of proposed post-closure care plan required by §146.93(a). | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 0 | $ - | $ - | $ - |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review emergency response plan required by §146.94(a). | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review proposed remedial response plan required by §146.94(b). | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review information required in § 146.82(c)1 prior to issuing permit. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |

| Compliance Activity | State Labor Cost ($/hour) A | Federal Labor Cost ($/hour) B | Regulatory Alternative C | One-time labor burden (hrs) D | State Cost E=A*C*0.56 | Federal Cost F=B*C*0.44 | Weighted Project Cost[2] G=E+F |
|---|---|---|---|---|---|---|---|
| Review information required under § 146.86(b)(1) to determine and specify casing and cementing requirements.2 | $49.44 | $50.14 | RA0 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA1 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review information required under § 146.86(c)(2) to determine and specify tubing and packer requirements.3 | $49.44 | $50.14 | RA0 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA1 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Evaluate mechanical integrity based on monitoring tests conducted since the last such evaluation and other mechanical integrity data. | $49.44 | $50.14 | RA0 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA1 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA2 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA3 | 3 | $ 83 | $ 66 | $ 149 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Witness logging and testing. | $49.44 | $50.14 | RA0 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA1 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA2 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA3 | 3 | $ 83 | $ 66 | $ 149 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review construction procedures. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review proposed injection procedure. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review schematics of proposed wells. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review contingency plans. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review plans (including maps) for meeting monitoring requirements. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review the corrective action proposed to be taken under §146.84 for wells within the area of review which penetrate the injection zone but are not properly completed or plugged. | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Review of the information described in § 146.82(c) prior to granting approval for plugging and abandonment of a well.1 | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Analyze the pressure decay and the transient pressures recorded by owner/operator pursuant to §146.90(e) and determine whether the injection activity has conformed with predicted values[§ 146.92(e)(1)].5 | $49.44 | $50.14 | RA0 | 12 | $ 333 | $ 264 | $ 597 |
| | | | RA1 | 12 | $ 333 | $ 264 | $ 597 |
| | | | RA2 | 12 | $ 333 | $ 264 | $ 597 |
| | | | RA3 | 24 | $ 666 | $ 528 | $ 1,194 |
| | | | RA4 | 24 | $ 666 | $ 528 | $ 1,194 |

| Compliance Activity | State Labor Cost ($/hour) A | Federal Labor Cost ($/hour) B | Regulatory Alternative C | One-time labor burden (hrs) D | State Cost E=A*C*0.56 | Federal Cost F=B*C*0.44 | Weighted Project Cost[2] G=E+F |
|---|---|---|---|---|---|---|---|
| Review of each project's annual reports submitted by all operators of Class VI wells [§ 146.91]1 and recordkeeping. | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA2 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA3 | 0 | $ - | $ - | $ - |
| | | | RA4 | 0 | $ - | $ - | $ - |
| Review of each project's semi-annual (RA3) or quarterly (RA0) reports submitted by all operators of Class VI wells [§ 146.91]2 and recordkeeping. | $49.44 | $50.14 | RA0 | 4 | $ 97 | $ 77 | $ 174 |
| | | | RA1 | 0 | $ - | $ - | $ - |
| | | | RA2 | 0 | $ - | $ - | $ - |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 0 | $ - | $ - | $ - |
| Review of each project's monthly reports submitted by all operators of Class VI wells [§ 146.91]3 and recordkeeping. | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 0 | $ - | $ - | $ - |
| | | | RA2 | 0 | $ - | $ - | $ - |
| | | | RA3 | 0 | $ - | $ - | $ - |
| | | | RA4 | 12 | $ 338 | $ 268 | $ 605 |
| Review AoR modeling update (simple model). | $49.44 | $50.14 | RA0 | 0 | $ - | $ - | $ - |
| | | | RA1 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA2 | 1 | $ 28 | $ 22 | $ 50 |
| | | | RA3 | 0 | $ - | $ - | $ - |
| | | | RA4 | 0 | $ - | $ - | $ - |
| Review AoR modeling update (complex model). | $49.44 | $50.14 | RA0 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA1 | 2 | $ 56 | $ 44 | $ 99 |
| | | | RA2 | 2 | $ 56 | $ 44 | $ 99 |
| | | | RA3 | 4 | $ 111 | $ 88 | $ 199 |
| | | | RA4 | 4 | $ 111 | $ 88 | $ 199 |
| Prepare / Review primacy applications. | $49.44 | $50.14 | RA0 | 0 / 0 | $ - | $ - | $ - |
| | | | RA1 | 1040 / 90 | $ 51,418 | $ 4,513 | $ 55,931 |
| | | | RA2 | 1040 / 90 | $ 51,418 | $ 4,513 | $ 55,931 |
| | | | RA3 | 1040 / 90 | $ 51,418 | $ 4,513 | $ 55,931 |
| | | | RA4 | 1040 / 90 | $ 51,418 | $ 4,513 | $ 55,931 |

Source: GS Cost Model

**Notes:**

(1) The project cost is independent of the project siting or size and constant across the various project types.

(2) Weighted permitting authority cost based on assumption of 56% of states currently active in the UIC program obtaining primacy for proposed Class VI wells (Section 5.2.1).

(3) Preparation of primacy applications is estimated to require 1040 hours by states, and 90 hours for EPA regional and headquarters offices to review.

**Sources:**

(A), (B) Permitting authority labor rate from Section 5.2.1.

(C) Burden and unit cost estimates reflect EPA's best professional judgment.

(D) Alternatives having the same application factor are grouped together. As described in Section 5.2, application factors represent the Agency's best estimate of the percentage of projects to which a given activity is expected to apply, or the extent to which each project under a given alternative is expected to engage in the activity (see Section 5.2).

(E), (F) Nondiscounted Project level cost estimates from GS Rule Cost Model.

## Exhibit 5.20 Permitting Authority Cost Estimates – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)

| Regulatory Alternative | State | Federal | Total | State | Federal | Total |
|---|---|---|---|---|---|---|
| | 3% | | | 7% | | |
| **Baseline** | $0.00 | $0.32 | $0.32 | $0.00 | $0.27 | $0.27 |
| **RA1** | $0.10 | $0.33 | $0.43 | $0.15 | $0.28 | $0.43 |
| **Incremental RA1** | $0.10 | $0.01 | $0.11 | $0.14 | $0.01 | $0.16 |
| **RA2** | $0.10 | $0.33 | $0.43 | $0.15 | $0.28 | $0.43 |
| **Incremental RA2** | $0.10 | $0.01 | $0.11 | $0.14 | $0.01 | $0.16 |
| **RA3** | $0.10 | $0.33 | $0.43 | $0.15 | $0.28 | $0.43 |
| **Incremental RA3** | $0.10 | $0.01 | $0.11 | $0.14 | $0.01 | $0.16 |
| **RA4** | $0.10 | $0.33 | $0.44 | $0.15 | $0.29 | $0.44 |
| **Incremental RA4** | $0.10 | $0.01 | $0.11 | $0.15 | $0.02 | $0.16 |

Source: Appendix C, Exhibit C.67/C.68

## 5.5 Estimated Costs to Households

EPA assumes that the increased costs for operation of GS wells under the GS Rule will be passed on, in whole or in part, to consumers. However, the impact on any individual household is expected to be very minor. Quantification of exact household costs is not possible due to the representative nature of the costing estimates. The representative project estimates used in this cost analysis are not connected to specific industry profiles that would include numbers and distributions of customers that could be used in household cost calculations. However, assumptions about the broader industry profile (i.e., types and characteristics of projects) can be used to qualitatively evaluate costs. In particular, the 29 projects estimated to be subject to the requirements of the GS Rule as part of this Cost Analysis are assumed to be sponsored by the energy sector. Because of the current government focus on the energy sector, there are many factors that will work to mitigate costs that are passed on to consumers.

As the major producers of $CO_2$, it is expected that large energy producers such as coal fired power plants will sponsor the majority of GS projects and therefore incur most of the costs of sequestration. Because of their roles as energy suppliers, these types of producers would be able to spread any cost increases across very large numbers of consumers. This is the major factor that works to minimize individual household cost increases. These potential increases may be further minimized depending on the regional or local regulatory structures in place. Energy prices are capped or subsidized in some areas based on the level of deregulation and resulting policies that are in place. In addition, many of the projects estimated as part of the project baseline are pilot-scale and as such may be subject to significant subsidies under various government programs to promote climate change mitigation technologies. The actual funding of these and other government programs (i.e., price limits or supports) will still be borne by consumers but most likely as part of a much larger tax base, especially for national programs. Overall, these considerations imply that any household costs resulting from the GS Rule will be minimal.

## 5.6 Comparison of Annualized Incremental Costs for All Regulatory Alternatives Considered

Exhibit 5.21 below summarizes the incremental costs of the GS Rule for each RA considered during the rule development process. Estimates represent those costs that EPA expects owners and operators and permitting authorities to incur for the 29 estimated baseline projects during the 50-year period of analysis.

Relative to the baseline regulatory scenario[10], Alternatives 1 through 4 have increasing incremental costs that range from $4.8 million to $48.1 million in annualized 2008$ (using a 3 percent discount rate). The incremental cost for the GS Rule (RA3) is approximately $38.1 million (using a 3 percent discount rate).

[10] As explained in the introductory paragraph of Chapter 4 of this Cost Analysis, the baseline regulatory scenario consists of Class I regulations for non-hazardous wells.

**Exhibit 5.21 Incremental Rule Costs for All Regulatory Alternatives Considered – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | Discount Rate | |
|---|---|---|
| | 3% | 7% |
| RA1 Incremental | $ 4.8 | $ 2.6 |
| RA2 Incremental | $ 14.5 | $ 11.4 |
| RA3 Incremental | $ 38.1 | $ 31.7 |
| RA4 Incremental | $ 48.1 | $ 39.5 |

Source: Appendix C, Exhibit C.74/C.75

### 5.6.1 Costs Summed by Type of Expenditure

As shown in Exhibit 5.22, operations and maintenance expenditures represent approximately 67% of the total incremental cost of the GS Rule (at 3% discounting). One-time costs, such as initial mapping of the project site geology and identification of existing penetrations in the projected AoR are approximately 17%. Capital expenditures represent the smallest portion of total cost at approximately 16%.

Sometimes costs annualized at 3% are higher than those at 7%, and vice versa. EPA notes that when calculating annualized costs, there is an inflection point where the annualization step can compensate for the difference in present values after the initial discounting step. The capital costs occur predominantly early in the analysis period; as a result, the discounting step for several of these cost items is only discounting at an average of 5-10 years, while the annualization is applied over 25 years. Whereas the values discounted using a 3 percent discount rate are higher than the same cost stream discounted using 7 percent, the annualization step moves the results in the other direction, i.e., towards the condition of the 7-percent discounted values being greater than the 3-percent values. In some cases the annualization step can more than compensate for the original difference in favor of a larger 3 percent present value and result in 7 percent annualized estimates greater than those using 3 percent. For O&M costs, which occur throughout the period of analysis and therefore are not subject to as great an annualization effect, the reverse generally can be seen; the annualized estimates are mostly greater based on a 3% discount rate as compared to a 7% discount rate.

**Exhibit 5.22 Incremental Rule Costs – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative | One-Time Discount Rate | | Capital Discount Rate | | O&M Discount Rate | | Total Discount Rate | |
|---|---|---|---|---|---|---|---|---|
| | 3% | 7% | 3% | 7% | 3% | 7% | 3% | 7% |
| RA1 Incremental | $ (2.1) | $ (2.8) | $ 1.2 | $ 1.5 | $ 5.6 | $ 4.0 | $ 4.8 | $ 2.6 |
| RA2 Incremental | $ 1.3 | $ 1.4 | $ 2.0 | $ 2.3 | $ 11.2 | $ 7.7 | $ 14.5 | $ 11.4 |
| RA3 Incremental | $ 6.6 | $ 7.0 | $ 6.0 | $ 7.0 | $ 25.4 | $ 17.7 | $ 38.1 | $ 31.7 |
| RA4 Incremental | $ 9.5 | $ 10.7 | $ 5.4 | $ 6.4 | $ 33.1 | $ 22.3 | $ 48.1 | $ 39.5 |

Source: Appendix C, Exhibit C.74/C.75

### 5.6.2 Costs Summed by Rule Component

Exhibit 5.23 provides a summary by rule component of the annualized costs (at discount rates of 3 and 7 percent) for each RA considered during the rule development process. It includes estimates of total and incremental costs that EPA expects owners and operators and permitting authorities to incur for the 29 estimated baseline projects over the 50-year period of analysis.

For RA 1 - 4, the most significant incremental rule costs (i.e., after subtracting baseline costs) are associated with monitoring. For RA 1 - 3, well operation is the second most significant incremental rule cost (for RA4, MIT is the second most significant incremental rule costs at 3% discounting, and Geologic Site Characterization at 7% discount rate). Monitoring represents a range from 44% to 77% of total incremental rule costs at three percent discounting. Well operation costs represent a range from 14% to 59% at 3 percent discounting.

The estimated cost for the GS Rule is the incremental cost for RA3 (approximately $38.1 million at 3% discount rate), which lies between the least costly and most costly RAs. The selection of RA3 for the final Rule is consistent with the results of the comparison of incremental costs and anticipated benefits of the rule, as discussed in Section 5.7, which also discusses these incremental costs as they relate to mitigation of the risk to USDWs related to GS.

**Exhibit 5.23 Total and Incremental Rule Costs by Regulatory Alternative and Rule Component – Annualized Values Using a 3% and 7% Discount Rate ($Millions, 2008$)**

| Regulatory Alternative/ Discount Rate | Geologic Site Characterization | Monitoring | Injection Well Construction | Area of Review | Well Operation | MIT | Well Plugging & Post Injection Site Care | Financial Responsibility | Permitting Authority Costs | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|
| **Baseline** | | | | | | | | | | |
| 3% | $ 6.7 | $ 3.4 | $ 16.2 | $ 1.1 | $ 41.8 | $ 0.2 | $ 0.6 | $ 0.0 | $ 0.3 | $ 70.2 |
| 7% | $ 8.3 | $ 2.9 | $ 17.0 | $ 1.0 | $ 28.2 | $ 0.1 | $ 0.2 | $ 0.0 | $ 0.3 | $ 58.1 |
| **RA1** | | | | | | | | | | |
| 3% | $ 4.1 | $ 7.1 | $ 16.5 | $ 1.1 | $ 44.6 | $ 0.2 | $ 0.9 | $ 0.0 | $ 0.4 | $ 75.0 |
| 7% | $ 5.1 | $ 6.1 | $ 17.4 | $ 1.0 | $ 30.2 | $ 0.1 | $ 0.3 | $ 0.0 | $ 0.4 | $ 60.8 |
| **Incremental RA1** | | | | | | | | | | |
| 3% | $ (2.6) | $ 3.7 | $ 0.4 | $ 0.1 | $ 2.8 | $ 0.1 | $ 0.3 | $ 0.0 | $ 0.1 | $ 4.8 |
| 7% | $ (3.2) | $ 3.2 | $ 0.4 | $ 0.1 | $ 1.9 | $ 0.0 | $ 0.1 | $ 0.0 | $ 0.2 | $ 2.6 |
| **RA2** | | | | | | | | | | |
| 3% | $ 7.4 | $ 11.4 | $ 17.3 | $ 1.1 | $ 45.9 | $ 0.2 | $ 0.9 | $ 0.0 | $ 0.4 | $ 84.7 |
| 7% | $ 9.2 | $ 9.0 | $ 18.3 | $ 1.0 | $ 31.0 | $ 0.1 | $ 0.4 | $ 0.0 | $ 0.4 | $ 69.5 |
| **Incremental RA2** | | | | | | | | | | |
| 3% | $ 0.7 | $ 8.0 | $ 1.1 | $ 0.1 | $ 4.1 | $ 0.1 | $ 0.3 | $ 0.0 | $ 0.1 | $ 14.5 |
| 7% | $ 0.9 | $ 6.1 | $ 1.2 | $ 0.1 | $ 2.8 | $ 0.0 | $ 0.1 | $ 0.0 | $ 0.2 | $ 11.4 |
| **RA3** | | | | | | | | | | |
| 3% | $ 11.3 | $ 22.0 | $ 17.4 | $ 1.5 | $ 50.3 | $ 2.7 | $ 2.8 | $ 0.0 | $ 0.4 | $ 108.3 |
| 7% | $ 14.1 | $ 18.7 | $ 18.4 | $ 1.3 | $ 34.2 | $ 1.7 | $ 1.0 | $ 0.0 | $ 0.4 | $ 89.8 |
| **Incremental RA3** | | | | | | | | | | |
| 3% | $ 4.6 | $ 18.6 | $ 1.2 | $ 0.4 | $ 8.5 | $ 2.6 | $ 2.2 | $ 0.0 | $ 0.1 | $ 38.1 |
| 7% | $ 5.7 | $ 15.8 | $ 1.4 | $ 0.3 | $ 5.9 | $ 1.6 | $ 0.8 | $ 0.0 | $ 0.2 | $ 31.7 |
| **RA4** | | | | | | | | | | |
| 3% | $ 14.3 | $ 24.4 | $ 16.9 | $ 1.5 | $ 48.5 | $ 8.9 | $ 3.3 | $ 0.0 | $ 0.4 | $ 118.3 |
| 7% | $ 17.9 | $ 20.1 | $ 18.0 | $ 1.5 | $ 33.0 | $ 5.6 | $ 1.2 | $ 0.0 | $ 0.4 | $ 97.6 |
| **Incremental RA4** | | | | | | | | | | |
| 3% | $ 7.6 | $ 21.0 | $ 0.7 | $ 0.5 | $ 6.7 | $ 8.7 | $ 2.7 | $ 0.0 | $ 0.1 | $ 48.1 |
| 7% | $ 9.5 | $ 17.2 | $ 0.9 | $ 0.5 | $ 4.8 | $ 5.5 | $ 0.9 | $ 0.0 | $ 0.2 | $ 39.5 |

Notes:
1) With the exception of the two pilot saline projects in the baseline, the GS Rule Cost Model does not capture the full PISC period for projects under the baseline and RA3, and because these costs mostly occur near (or after) the end of the 50 year period of analysis they are also significantly influenced by the discount rate.
2) Costs related to demonstration of Financial Responsibility are less than $100,000 in annualized terms.
3) Detail may not add due to rounding.
Source: Appendix C, Exhibit C.67/C.68

## 5.7 Comparison of Costs and Benefits

EPA is limited by the purpose, quality, and quantity of data available in developing meaningful benefits analyses. In the absence of additional statistical analyses, only general observations of the data can be made with qualifiers. A quantitative comparison of risk between the alternatives considered for the final Rule would require robust data that would support: 1) direct comparisons of the overall baseline conditions with the overall conditions under each of the alternatives, or 2) comparisons of specific regulatory components (i.e., geologic site characterization) that could be used to compare the baseline and all alternatives. Currently, the risk of contamination of USDWs from GS activities has not been directly measured for any injection parameters or site characteristics. Thus, costs can only be compared to the qualitative relative risks discussed in Ch. 4.

Compared to the baseline condition of the current UIC Program regulations, RA3 offers significantly greater protection to USDWs because that RA (the final Rule) is tailored specifically to GS and includes requirements necessary to prevent endangerment via migration of fluids into USDWs; existing well classes I – V do not specifically address the unique nature of injection of $CO_2$ for the purposes of GS. RA4 has more stringent standards and greater costs compared to the final Rule, but EPA believes that RA4 requirements are beyond what is necessary to provide adequate risk reduction to USDWs. RA1 and RA2 provide lower costs than RA3 but at increased levels of risk to USDWs. Although RA4 has more stringent requirements, EPA does not believe that the increased requirements and the increased costs are necessary to provide protection to USDWs. Therefore EPA believes that RA3 is the best alternative.

## 5.8 Other Economic Measures

The lack of a quantitative risk assessment prevents the use of other economic measures, specifically, a break-even analysis and measures of cost effectiveness based on the value of changes in health conditions.

## 5.9 Non-quantified Costs and Uncertainties in Cost Estimates

### 5.9.1 Non-quantified Costs

The purpose of the GS Rule is to mitigate any risk introduced by GS activities to the quality, and indirectly volume, of current and potential future USDWs. The requirements of the GS Rule are specifically designed to mitigate such risks and to provide some redundancy in these protections. However, should there be an instance of failure to protect a USDW through inappropriate implementation of the GS Rule or GS deployment in a way not consistent with the GS Rule; the cost to society would be either the cost of returning the water to usable quality or the cost of developing an alternative source of drinking water in some cases. There is most likely a very low probability of such a failure being attributable to the GS Rule itself; this would entail the GS Rule being non-implementable or not readily comprehensible for proper implementation, and then either of these circumstances resulting in activity that causes contamination of a USDW.

Should the GS Rule somehow impede GS deployment, then the opportunity costs of not capturing the benefits associated with GS could be attributed to the GS Rule; however, EPA has tried to develop a rule that balances risk with practicability and economic considerations and believes the probability of such impedance is very low. The GS Rule should serve to bolster public confidence in GS by establishing requirements that manage risks to human health and the environment through protection of USDWs. EPA expects the GS Rule to enhance public acceptance of GS technology and provide national consistency and regulatory certainty to owners and operators of GS wells. Thus, EPA believes the GS Rule will not impede deployment of GS projects.

### 5.9.2 Uncertainties in Cost Estimates

As described in the *Geologic $CO_2$ Sequestration Technology and Cost Analysis* (EPA, 2010a) developed in support of this Cost Analysis, many assumptions in the model include uncertainty; the general areas of uncertainty include the project characteristics of the five pro forma projects, the unit costs of technology, the frequency of each compliance activity appropriate for each given project site, estimates of labor burden and hourly wage rates, and changes in costs over time (caused by market forces or improved technology, for example).

EPA considered in particular the uncertainty in three basic assumptions used in the Cost Analysis: 1) the estimated number of projects that will be affected by the GS Rule; 2) the labor rates applied; and 3) the estimated number of monitoring wells to be constructed per project to adequately monitor in a given geologic setting.

Under the current baseline assumption there will be 29 projects affected by the GS rule in the 50-year analysis period, as described in Chapter 3 of this Cost Analysis. If limits on emissions of greenhouse gases were imposed, GS would allow the United States to continue to use fossil fuels to a larger extent than otherwise possible; with the widespread occurrence of saline formations across the United States, GS could be deployed nationwide under such a scenario. Therefore, the number of projects that will deploy from 2011 through 2060 may be significantly underestimated in this analysis if legislation that provides an incentive for GS should be enacted. Alternatively, should the public have a negative perception to GS deployment, the number of projects could be overestimated.

Second, this analysis considered how the Cost Analysis results would change if the labor rates used for Geoscientists and Mining and Geological Engineers (presented in Section 5.2.1 of this Cost Analysis) were significantly underestimated. If a rapid increase in demand for this labor occurred under future climate change legislation and outpaced the development of an equal supply of such labor, some period of increased labor costs would be expected. However, a rapid wide scale increase in deployment is not expected, according to the Joint Global Change Research Institute (Dooley, 2010), therefore the uncertainty in labor costs is not considered to contribute significantly to the uncertainty in this cost analysis.

Third, EPA assumes that the number of monitoring wells per project is correlated to the size of the site, which is the AoR. As shown in Exhibit 5.2, the representative pilot-scale saline project site is assumed to be approximately one square mile and under the selected alternative (RA3) is assumed to have two monitoring wells, one that is drilled into the injection zone (IZ) and one above the IZ. For the representative large-scale saline project, the site is assumed to be

approximately 23 square miles with 12 monitoring wells, six that are drilled into the injection zone and six above the IZ. For the representative transitioning Class II ER project, the site is assumed to be approximately 8 square miles with four monitoring wells, two that are drilled into the IZ and two above the IZ. In the limited circumstances where injection depth waivers are approved, sites are assumed to have 50% more monitoring wells than those estimated above. For the purpose of estimating national costs, however, EPA recognizes that more or fewer monitoring wells may be appropriate depending on project site characteristics. Because the monitoring wells and associated costs represent a significant component of the Cost Analysis, EPA acknowledges that this factor may be significant in the overall uncertainty of the Cost Analysis.

Additional uncertainties correspond more directly to specific assumptions made in constructing the cost model. If the assumptions for such items are incorrect, there may be significant cost implications outside of the general price level uncertainties discussed above. The most prominent examples of these are:

- It is assumed that all projects have access to an existing fluid flow model that can be customized for the project by updating input parameters. If GS well owners and operators have to develop such a model for new projects from scratch, modeling costs may increase by four to five times.

- It is assumed that partially corrosion resistant cement can be used for injection well construction. If GS well owners and operators have to utilize corrosion resistant alloys, construction costs can increase significantly.

- Assumptions made for several cost components and subcomponents are based on industry averages. However, the actual costs of several cost components such as finding wells in AoR, land use and rights, and remediation of failures can vary widely based on site specific characteristics. To the degree that EPA's assumptions about the "representative" projects differs from cost factors of those that eventually deploy, costs for such rule components could be significantly over- or underestimated.

- As detailed in Section 5.0 of the *Geologic $CO_2$ Sequestration Technology and Cost Analysis* (EPA, 2010a), underlying trends in equipments costs will have an impact on costs incurred by owners and operators after the GS Rule is promulgated. Generally speaking, the unit costs for which there is greater certainty are those directly or indirectly related to conventional drilling and completion practices and geophysical techniques used in exploration and development for oil and gas. Some equipment costs, i.e., pipeline, are well known in the industry but vary based on market forces affecting supply and demand for materials and labor.

- Owners and operators would, if directed, develop and implement a plan for surface air monitoring and/or soil gas monitoring to detect leakage of $CO_2$ to ensure that $CO_2$ and any other contaminants moving with the $CO_2$ have not migrated through USDWs. Costs associated with air monitoring are accounted for under the Mandatory Reporting Rule of Greenhouse Gases - Subpart RR (MRR). However, in the event that additional air monitoring is needed for GS wells (beyond what is required under MRR), the GS Rule monitoring costs could be under-estimated.

Based on the considerations discussed above, EPA conducted sensitivity analyses to evaluate the potential impacts of changes in certain key assumptions in the cost analysis. These analyses include:

1) Considering 5 and 54 projects as the lower and upper bound number of projects deployed;

2) An increase of 50% in industry labor rates used; and

3) A 25% increase and decrease in monitoring wells per project site.

To address the uncertainty inherent in projecting the GS baseline, sensitivity analyses that further explore the implications of alternative climate policy scenarios have been performed. These analyses are comparable to analyses performed to support the Regulatory Impact Analysis for Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of $CO_2$ Rule (Subpart RR).[11] The sensitivity analyses consider 5 and 54 projects as the lower and upper bound project numbers to be consistent with the Subpart RR analysis. The sensitivity analysis numbers (5 and 54 projects) are based on projected deployment highlighted in the presidential memorandum establishing the CCS Task Force and an EPA legislative analysis model of deployment under the American Power Act, respectively. As shown in Exhibit 5.24a, assuming 5 pilot saline projects are implemented during the period of analysis results in annualized RA 3 incremental rule costs that are approximately $2.3 million. And, as shown in Exhibit 5.24b, assuming 54 large saline projects are implemented during the period of analysis results in annualized RA 3 incremental rule costs that are approximately $235 million. Consideration of an increase in projects based on climate change legislation could result in a significant increase in rule costs.

In considering the sensitivity of analysis results to changes in labor rates, EPA found that a 50% increase in industry labor rates results in annualized incremental rule costs of $38.6 million based on a 3 percent discount rate, or approximately a 1% increase in costs from the primary analysis. An important caveat to this analysis is that it captures the increase for only those project costs for which a distinct labor component has been defined; for those that have a labor component embedded in the cost, that cost has not been increased by this sensitivity analysis. Therefore, to the degree that labor costs are embedded in project costs, this sensitivity analysis underestimates the extent of increase that a 50% labor increase would induce. The *Geologic $CO_2$ Sequestration Technology and Cost Analysis* (EPA, 2010a) provides detail on how individual compliance and business-as-usual (baseline) activities are defined for costing purposes, and a brief text description accompanies each unit cost algorithm in the matrix presented in Appendix B to this Cost Analysis.

In this Cost Analysis EPA assumes that owners and operators under the GS Rule (RA3) will construct and operate a certain ratio of monitoring wells per project site area depending on project type (see Exhibit 5.2 for the pro forma types used in this analysis) to conduct necessary

[11] Simultaneous development of the Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of $CO_2$ Rule (Subpart RR) and the GS Rule was coordinated by EPA. As a part of the coordinated rule making efforts, EPA developed these sensitivity analyses to ensure consistency of requirements and costs between the two rules.

monitoring of the injected $CO_2$ and its plume. Because the actual number that will be necessary for a given project site is uncertain, EPA tested the sensitivity of cost estimates to the number of monitoring wells by applying a 25 percent decrease and increase of monitoring wells per project site area to the original assumptions for each project type. This change results in annualized incremental rule costs of approximately $33.0 million and $43.1 million, or a 13 percent decrease or increase from the primary analysis results of $38.1 million at a 3% discount rate (as shown in Exhibit 5.26).

An additional analysis EPA performed was a calculation of the rule costs for the baseline 29 projects on the basis of formation type and project scale. To be commensurate with the treatment (annualization) of costs, the injected volumes are discounted, that is, put in present value terms for the amount injected over 50 years, and then annualized over the first 25 years of the analysis period (see Section 5.3 for further explanation of the annualization). The results indicate that the pilot-scale saline projects, which must adhere to the same level of protectiveness as the large-scale projects, don't achieve the same economies of scale as the large-scale projects: pilot-scale saline projects cost significantly more per ton $CO_2$ sequestered (147% more with 3% discounting and 77% more with 7% discounting) than large-scale saline projects.

The results for each sensitivity analysis calculated using 3 and 7 percent discount rates are presented in Appendix C of the Cost Analysis.

### Exhibit 5.24a Total and Incremental Rule Costs by Cost Type, Assuming 5 Pilot Saline Projects are Implemented During the Period of Analysis ($Millions, 2008$)

| Regulatory Alternative | One-Time Costs | | Capital Costs | | O&M Costs | | Total Costs | |
|---|---|---|---|---|---|---|---|---|
| | Cost, 2008$ | Increase or Decrease, $2008[1] | Cost, 2008$ | Increase or Decrease, $2008[1] | Cost, 2008$ | Increase or Decrease, $2008[1] | Cost, 2008$ | Increase or Decrease, $2008[1] |
| **3 Percent Discount Rate** | | | | | | | | |
| **RA0** | $ 1.0 | $ (8.9) | $ 3.0 | $ (12.5) | $ 1.8 | $ (43.0) | $ 5.8 | $ (64.4) |
| **RA1** | $ 0.8 | $ (7.1) | $ 3.0 | $ (13.8) | $ 1.8 | $ (48.6) | $ 5.6 | $ (69.4) |
| **RA1 Incremental** | $ (0.2) | $ 1.9 | $ (0.0) | $ (1.2) | $ 0.0 | $ (5.6) | $ (0.2) | $ (4.9) |
| **RA2** | $ 1.2 | $ (10.1) | $ 3.2 | $ (14.3) | $ 1.9 | $ (54.1) | $ 6.2 | $ (78.5) |
| **RA2 Incremental** | $ 0.1 | $ (1.2) | $ 0.2 | $ (1.8) | $ 0.1 | $ (11.1) | $ 0.4 | $ (14.1) |
| **RA3** | $ 2.0 | $ (14.6) | $ 3.6 | $ (17.9) | $ 2.5 | $ (67.7) | $ 8.1 | $ (100.2) |
| **RA3 Incremental** | $ 0.9 | $ (5.7) | $ 0.6 | $ (5.4) | $ 0.7 | $ (24.7) | $ 2.3 | $ (35.8) |
| **RA4** | $ 2.6 | $ (16.9) | $ 3.7 | $ (17.2) | $ 3.2 | $ (74.7) | $ 9.5 | $ (108.8) |
| **RA4 Incremental** | $ 1.6 | $ (8.0) | $ 0.7 | $ (4.7) | $ 1.4 | $ (31.7) | $ 3.7 | $ (44.4) |
| **7 Percent Discount Rate** | | | | | | | | |
| **RA0** | $ 1.5 | $ (9.8) | $ 4.3 | $ (12.2) | $ 2.2 | $ (28.2) | $ 7.9 | $ (50.2) |
| **RA1** | $ 1.2 | $ (7.2) | $ 4.3 | $ (13.7) | $ 2.2 | $ (32.2) | $ 7.6 | $ (53.1) |
| **RA1 Incremental** | $ (0.3) | $ 2.5 | $ (0.0) | $ (1.5) | $ 0.0 | $ (4.0) | $ (0.3) | $ (2.9) |
| **RA2** | $ 1.7 | $ (10.9) | $ 4.6 | $ (14.2) | $ 2.3 | $ (35.8) | $ 8.5 | $ (61.0) |
| **RA2 Incremental** | $ 0.2 | $ (1.2) | $ 0.3 | $ (2.0) | $ 0.1 | $ (7.6) | $ 0.6 | $ (10.8) |
| **RA3** | $ 2.6 | $ (15.6) | $ 5.2 | $ (18.3) | $ 3.0 | $ (45.1) | $ 10.7 | $ (79.0) |
| **RA3 Incremental** | $ 1.1 | $ (5.9) | $ 0.9 | $ (6.1) | $ 0.8 | $ (16.8) | $ 2.8 | $ (28.8) |
| **RA4** | $ 3.3 | $ (18.6) | $ 5.3 | $ (17.6) | $ 3.6 | $ (49.2) | $ 12.2 | $ (85.4) |
| **RA4 Incremental** | $ 1.9 | $ (8.9) | $ 1.0 | $ (5.4) | $ 1.4 | $ (20.9) | $ 4.3 | $ (35.2) |

[1] As compared to GS Rule deployment schedule of 29 projects.
Source: Appendix C, Exhibit C.81

## Exhibit 5.24b Total and Incremental Rule Costs by Cost Type, Assuming 54 Large Saline Projects are Implemented During the Period of Analysis ($Millions, 2008$)

| Regulatory Alternative | One-Time Costs | | Capital Costs | | O&M Costs | | Total Costs | |
|---|---|---|---|---|---|---|---|---|
| | Cost, 2008$ | Increase or Decrease, $2008[1] | Cost, 2008$ | Increase or Decrease, $2008[1] | Cost, 2008$ | Increase or Decrease, $2008[1] | Cost, 2008$ | Increase or Decrease, $2008[1] |
| **3 Percent Discount Rate** | | | | | | | | |
| **RA0** | $ 64 | $ 54 | $ 98 | $ 82 | $ 300 | $ 255 | $ 462 | $ 391 |
| **RA1** | $ 42 | $ 34 | $ 104 | $ 87 | $ 325 | $ 274 | $ 471 | $ 396 |
| **RA1 Incremental** | $ (23) | $ (21) | $ 6 | $ 5 | $ 25 | $ 20 | $ 9 | $ 4 |
| **RA2** | $ 65 | $ 54 | $ 108 | $ 91 | $ 362 | $ 306 | $ 535 | $ 451 |
| **RA2 Incremental** | $ 1 | $ (0) | $ 10 | $ 8 | $ 62 | $ 51 | $ 74 | $ 59 |
| **RA3** | $ 94 | $ 78 | $ 140 | $ 118 | $ 462 | $ 392 | $ 696 | $ 588 |
| **RA3 Incremental** | $ 30 | $ 23 | $ 42 | $ 36 | $ 162 | $ 137 | $ 235 | $ 196 |
| **RA4** | $ 126 | $ 106 | $ 142 | $ 121 | $ 521 | $ 443 | $ 788 | $ 670 |
| **RA4 Incremental** | $ 61 | $ 52 | $ 44 | $ 39 | $ 222 | $ 188 | $ 327 | $ 279 |
| **7 Percent Discount Rate** | | | | | | | | |
| **RA0** | $ 72 | $ 61 | $ 111 | $ 94 | $ 201 | $ 171 | $ 384 | $ 326 |
| **RA1** | $ 46 | $ 38 | $ 118 | $ 100 | $ 219 | $ 184 | $ 383 | $ 322 |
| **RA1 Incremental** | $ (26) | $ (23) | $ 7 | $ 6 | $ 18 | $ 14 | $ (1) | $ (4) |
| **RA2** | $ 73 | $ 60 | $ 123 | $ 104 | $ 242 | $ 204 | $ 438 | $ 368 |
| **RA2 Incremental** | $ 1 | $ (1) | $ 12 | $ 10 | $ 41 | $ 33 | $ 54 | $ 42 |
| **RA3** | $ 105 | $ 87 | $ 159 | $ 135 | $ 312 | $ 263 | $ 575 | $ 485 |
| **RA3 Incremental** | $ 33 | $ 26 | $ 48 | $ 41 | $ 111 | $ 93 | $ 191 | $ 159 |
| **RA4** | $ 140 | $ 118 | $ 161 | $ 138 | $ 350 | $ 297 | $ 651 | $ 553 |
| **RA4 Incremental** | $ 68 | $ 57 | $ 50 | $ 44 | $ 149 | $ 126 | $ 267 | $ 227 |

[1] As compared to GS Rule deployment schedule of 29 projects.
Source: Appendix C, Exhibit C.82

## Exhibit 5.25 Total and Incremental Rule Costs Based on 50% Increased Labor Rate - Annualized Values Using a 3% Discount Rate ($Millions, 2008$)

| Regulatory Alternative | One-Time Costs | % Change | Capital Costs | % Change | O&M Costs | % Change | Total | % Change |
|---|---|---|---|---|---|---|---|---|
| **RA0** | $ 10.1 | 2% | $ 15.5 | 0% | $ 44.9 | 0% | $ 70.6 | 1% |
| **RA1** | $ 8.1 | 2% | $ 16.7 | 0% | $ 50.6 | 0% | $ 75.4 | 1% |
| **RA1 Incremental** | $ (2.1) | 0% | $ 1.2 | 0% | $ 5.6 | 1% | $ 4.8 | 1% |
| **RA2** | $ 11.5 | 2% | $ 17.5 | 0% | $ 56.2 | 1% | $ 85.2 | 1% |
| **RA2 Incremental** | $ 1.3 | 1% | $ 2.0 | 0% | $ 11.3 | 1% | $ 14.7 | 1% |
| **RA3** | $ 16.9 | 2% | $ 21.5 | 0% | $ 70.8 | 1% | $ 109.2 | 1% |
| **RA3 Incremental** | $ 6.7 | 1% | $ 6.0 | 0% | $ 25.9 | 2% | $ 38.6 | 2% |
| **RA4** | $ 19.9 | 2% | $ 20.9 | 0% | $ 78.6 | 1% | $ 119.4 | 1% |
| **RA4 Incremental** | $ 9.7 | 2% | $ 5.4 | 0% | $ 33.7 | 2% | $ 48.8 | 1% |

% change shows difference between primary analysis and model run using 50% increased labor rate.
Source: Appendix C, Exhibit C.82

## Exhibit 5.26 Total and Incremental Rule Costs, Change in Cost from Primary Analysis Resulting from 25% Increase/Decrease in Monitoring Wells - Annualized Values Using a 3% Discount Rate ($Millions, 2008$)

| Regulatory Alternative | | One-Time Costs | % Change | Capital Costs | % Change | O&M Costs | % Change | Total | % Change |
|---|---|---|---|---|---|---|---|---|---|
| Primary Analysis Assumption | RA0 | $ 10.0 | 0% | $ 15.5 | 0% | $ 44.8 | 0% | $ 70.2 | 0% |
| | RA3 | $ 16.6 | 0% | $ 21.5 | 0% | $ 70.2 | 0% | $ 108.3 | 0% |
| | RA3 Incremental | $ 6.6 | 0% | $ 6.0 | 0% | $ 25.4 | 0% | $ 38.1 | 0% |
| 25% decrease | RA0 | $ 9.9 | -1% | $ 15.3 | -1% | $ 44.0 | -2% | $ 69.2 | -2% |
| | RA3 | $ 16.3 | -2% | $ 20.1 | -6% | $ 65.8 | -6% | $ 102.2 | -6% |
| | RA3 Incremental | $ 6.4 | -4% | $ 4.8 | -20% | $ 21.8 | -14% | $ 33.0 | -13% |
| 25% increase | RA0 | $ 10.0 | 1% | $ 15.7 | 1% | $ 45.6 | 2% | $ 71.3 | 2% |
| | RA3 | $ 16.9 | 2% | $ 22.9 | 6% | $ 74.6 | 6% | $ 114.4 | 6% |
| | RA3 Incremental | $ 6.9 | 4% | $ 7.2 | 20% | $ 29.0 | 14% | $ 43.1 | 13% |

Source: Appendix C, Exhibit C.84

## Exhibit 5.27 Annualized Rule Costs By Project Type Per Metric Tonne and Per Project (2008$)

| Project Type | Metric Tonnes of CO2 Injected (3%)[1] | Metric Tonnes of CO2 Injected (7%)[2] | No. of Projects Deployed | Annualized Incremental Cost by Project Type ($MM) | | Annualized Incremental Rule Cost Per Metric Tonne ($) | | Annualized Incremental Rule Cost Per Project ($MM) | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | 3% | 7% | 3% | 7% | 3% | 7% |
| Pilot Saline | 268,360 | 17,992,359 | 2.0 | 0.8 | 0.8 | 3.11 | 2.73 | 0.42 | 0.40 |
| Large Saline | 20,197,218 | 18,962,247 | 9.4 | 25.4 | 22.8 | 1.26 | 1.54 | 2.70 | 2.42 |
| Large Saline Waivered | 1,122,068 | 969,888 | 0.5 | 4.6 | 4.4 | 4.13 | 5.41 | 8.87 | 8.51 |
| ER | 5,553,462 | 18,962,247 | 13.7 | 5.8 | 2.9 | 1.04 | 1.00 | 0.42 | 0.21 |
| ER Waivered | 282,815 | 969,888 | 0.8 | 1.4 | 0.8 | 5.04 | 5.26 | 1.88 | 1.03 |
| All Formations | 27,423,922 | 18,962,247 | 26.4 | 38.1 | 31.8 | 1.39 | 1.67 | 1.44 | 1.20 |

Source: Appendix C, Exhibit C.77

Note: It is estimated that 25 - 26 of the 29 baseline projects (depending on the RA) will successfully deploy over the 50 year period of analysis. Annualized rule cost per project is based on the number of successfully deployed projects.

[1] Injected volumes are discounted to the first year of the analysis and annualized over 25 years at 3% discounting for comparability to annualized costs.

[2] Injected volumes are discounted to the first year of the analysis and annualized over 25 years at 7% discounting for comparability to annualized costs.

# 6. Economic Impact Analysis

## 6.1 Introduction

As part of the rulemaking process, United States Environmental Protection Agency (EPA) is required to address the direct and indirect burdens that the Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide ($CO_2$) Geologic Sequestration (GS) Wells (GS Rule) may place on certain types of governments, business, and populations. This chapter presents the analyses performed by EPA in accordance with the following 12 Federal mandates:

1. Executive Order 12866: Regulatory Planning and Review.

2. Paperwork Reduction Act (PRA) (a separate Information Collection Request (ICR) document contains the complete analysis).

3. The Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996.

4. Unfunded Mandates Reform Act (UMRA) of 1995.

5. Executive Order 13132 (Federalism).

6. Executive Order 13175 (Consultation and Coordination with Indian Tribal Governments).

7. Executive Order 13045 (Protection of Children from Environmental Health Risks and Safety Risks).

8. Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use).

9. National Technology Transfer and Advancement Act (NTTAA) of 1995.

10. Executive Order 12898 (Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations).

Many of the requirements and EOs listed above call for an explanation of why the rule is necessary, the statutory authority for the rule, and the primary objectives that the rule is intended to achieve (refer to Chapter 2 for more information regarding the objectives of the rule). Others are designed to assess the financial and health effects of the rule on certain subpopulations such as low-income, minority, and tribal populations.

## 6.2 Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action" because it is anticipated to raise novel legal and policy issues, as it is creating a new class of UIC wells to regulate $CO_2$ injection for a new purpose. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

## 6.3 Paperwork Reduction Act

The information collection requirements in this rule will be submitted for approval to the OMB under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq*. The information collection requirements are not enforceable until OMB approves them.

The information collected as a result of this rule will allow EPA and State permitting authorities to review geologic information about a proposed injection project to evaluate its suitability for safe and effective GS. It also allows the Agency to fulfill the requirements of the UIC Program to verify throughout the life of the injection project that protective requirements are in place and that Underground Sources of Drinking Water (USDWs) are protected. The collection requirements are mandatory under the Safe Drinking Water Act (SDWA). (42 U.S.C. 300h *et seq.*).

For the first three years after publication of the final rule in the Federal Register, the major information requirements apply to a total of 38 respondents, for an average of 12.6 respondents per year. The total incremental burden (for owners and operators, permitting authorities, and the Agency) associated with the change in moving from the information requirements of the UIC Program for Class I non-hazardous wells (baseline) to the selected alternative under the GS Rule over the three years covered by the ICR is 53,740 hours, for an average of 17,913 hours per year. The total incremental cost over the three-year clearance period is $36.9 million, for an average of $12.3 million per year (simple average over three years). The average burden hours per response (i.e., the amount of time needed for each activity that requires a collection of information) is 423 hours; the average cost per response is $290,695. The collection requirements are mandatory under SDWA (42 U.S.C. 3501 *et seq.*). Details on the calculation of the rule information collection burden and costs can be found in the ICR (USEPA, 2010b) and Chapter 5 of this Cost Analysis. A summary of the burden and costs of the collection is presented in Exhibit 6-1 below.

**Exhibit 6-1 Average Annual Net Change Burden and Costs for the GS ICR**

| Respondent Type | Annual Respondents | Annual Burden Hours | Cost | | | | Annual Responses |
|---|---|---|---|---|---|---|---|
| | | | Annual Labor Cost | Annual Capital Cost | Annual O&M Cost | Total Annual Cost | |
| **Owners or Operators** | 1.0 | 1,549 | $ 204,574 | $ 5,827,027 | $ 5,454,346 | $ 11,485,946 | 6.9 |
| **Permitting Authorities** | 10.7 | 11,241 | $ 555,763 | $ - | $ - | $ 555,763 | 23.6 |
| **Agency** | 1.0 | 5,123 | $ 256,880 | $ - | $ - | $ 256,880 | 11.7 |
| **Total** | 12.6 | 17,913 | $ 1,017,217 | $ 5,827,027 | $ 5,454,346 | $ 12,298,589 | 42.3 |

Source:
Information Collection Request for the Geologic Sequestration Rule (USEPA, 2010b).
Notes:
1) Detail may not add exactly to total due to independent rounding.
2) "Annual Burden Hours" reflects an annual average for all project types over the 3-year ICR period.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. In addition, EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information requirements contained in this final rule.

## 6.4 Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedures Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

The RFA provides default definitions for each type of small entity. Small entities are defined under the RFA as: (1) a small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any "not-for-profit enterprise which is independently owned and operated and is not dominant in its field."

For the purpose of assessing the impacts of the GS Rule on small entities, would include the following (1) For electric power plants under North American Industry Classification System (NAICS) codes 221111, 221112, 221113, 221119, 221121, 221122, a firm that is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours; (2) For petroleum refineries under NAICS code 324110, as specified for government procurement purposes, a firm must have fewer than 1,500 employees and less than 125,000 barrels per calendar day in total Operable Atmospheric Crude Oil Distillation capacity. Capacity would include owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. See 73 FR 43492 (July 2008).

However, GS is a voluntary action that would only be undertaken by a small entity if GS were in its interest compared to other alternatives it may have. The purpose of the GS regulation is to ensure that, where deployed, GS is conducted in a manner that protects USDWs from endangerment. GS is a technologically complex activity, the cost of which is anticipated to be prohibitive to small entities. Therefore, it is expected that small entities would not elect to sequester $CO_2$ via injection wells, and thus the rule will not have any impact on them. In summary, EPA certifies that the GS Rule will not generate a significant economic impact on a substantial number of small entities.

## 6.5 Unfunded Mandates Reform Act (UMRA)

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. The total annual incremental costs estimated for the implementation of this rule are well under $100 million, resulting in expenditures for the entity groupings required under an UMRA analysis that also fall far below the $100 million per year threshold. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Government responsibilities for oversight and implementation of this rule reside with State or Federal agencies and not with small governments.

## 6.6 Executive Order 13132: Federalism

Under section 6(b) of EO 13132 (64 FR 43255, August 10, 1999), EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed action. In addition, under section 6(c) of EO 13132, EPA may not issue an action that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the proposed action.

EPA has concluded that this action may have federalism implications. It will change the UIC Program, and increase the stringency of regulation of GS projects (which would otherwise have been permitted under UIC as Class I wells). This rule will not impose substantial direct compliance costs on State or Local governments, nor does EPA anticipate that it will preempt State law. Thus, the requirements of sections 6(b) and 6(c) of the EO do not apply to this action.

Consistent with EPA policy, EPA nonetheless consulted with representatives of State and local governments early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. Representatives included the National Governors' Association, the National Conference of State Legislatures, the Council of State Governments, the National League of Cities, the US Conference of Mayors, the National

Association of Counties, the International City/County Management Association, the National Association of Towns and Townships, and the County Executives of America.

## 6.7 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the EO 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has Tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by Tribal governments, or EPA consults with Tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. Indian Tribes may voluntarily apply for primary enforcement responsibility to regulate the UIC Program in lands under their jurisdiction (See section II.G of the Preamble for more details on Primacy). Currently, two Tribes have received primacy for the UIC Program under section 1425 of SDWA since the publication of the proposed rule. EPA is responsible for implementing the UIC Program in the event that States or Tribes do not seek primary enforcement responsibility. EPA clarifies that regardless of whether Tribes have UIC Program primacy, the rule protects USDWs from contamination and therefore protects all populations from adverse health effects related to potential USDW contamination.

EPA consulted with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of the tribal consultation calls are included in the docket for the GS rulemaking. See section II of the Preamble for more information on the details of the tribal consultation process.

As required by section 7(a), EPA's Tribal Consultation Official has certified that the requirements of the  (EO) have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

## 6.8 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is not subject to EO 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. Today's rule does not require or provide incentive for firms to engage in GS, however, it does protect USDWs from potential negative impacts from GS of $CO_2$ should a firm decide to undertake such a project. Health and risk assessments related to GS of $CO_2$ and its effects on humans and the environment are presented in the *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide* (USEPA, 2010c). Additionally, EPA notes that it is funding and monitoring research related to the potential for USDW contamination associated with GS projects. Much of this research focuses on potential exceedances of drinking water standards (as suggested), which were developed by EPA and take

into account impacts on children. Please see section II of the Preamble for more details on this research.

## 6.9 Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This rule is not a "significant energy action" as defined in EO 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. In absence of climate change legislation, baseline assumptions developed with the Department of Energy (DOE) for this rulemaking indicate that only approximately 1% of the existing $CO_2$ emissions will be sequestered (approximately 1.0 billion metric tons) over the period of analysis. Furthermore, the higher degree of regulatory certainty and clarity in the permitting process may, in fact, have a positive effect on the energy sector.

Specifically, if climate change legislation that imposes caps or taxes on $CO_2$ emissions is passed in the future, energy generation firms and other $CO_2$ producing industries will have an economic incentive to reduce emissions, and this rule will provide regulatory certainty in determining how to maximize operations (for example, by increasing production while staying within the emissions cap or avoiding some carbon taxes). The rule may allow some firms to extend the life of their existing capital investment in plant machinery or plant processes.

## 6.10 National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA, Public Law No. 104-113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves environmental monitoring or measurement. Consistent with the Agency's Performance Based Measurement System ("PBMS"), EPA has decided not to require the use of specific, prescribed analytic methods. Rather, the rule will allow the use of any method that meets the prescribed performance criteria. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified.

## 6.11 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

EO 12898 (59 FR 7629, Feb. 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent

practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations.

Existing electric power generation plants that burn fossil fuels may be more prevalent in areas with higher percentages of people who are minorities or have lower incomes on average, but it is hard to predict where new plants with Carbon Capture and Storage (CCS) will be built. EPA is developing guidance for UIC Directors that places emphasis on considering the potential impact of any GS permits on communities (such as minority and low income populations) when evaluating Class VI injection well permit applications, as well as provides suggestions and tools for targeted outreach to ensure more meaningful public input and participation from the most affected communities during the permit evaluation and approval process.

This rule does not require that GS be undertaken; but does require that if it is undertaken, owners and operators will conduct the activity in such a way as to protect USDWs from endangerment caused by $CO_2$. Additionally, this rule will ensure that all areas of the United States are subject to the same minimum Federal requirements for protection of USDWs from endangerment from GS. Additional detail regarding the potential risk of the rule is presented in the *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide* (USEPA, 2010c).

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