November 2010

Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Subpart RR and Subpart UU: Injection and Geologic Sequestration of Carbon Dioxide

Final Report

CONTENTS

LIST OF TABLES

SECTION 1
INTRODUCTION AND BACKGROUND

1.1 Greenhouse Gas Reporting Program Background

The Greenhouse Gas (GHG) Reporting Program requires reporting of GHG emissions and other relevant information from certain source categories in the United States. The GHG Reporting Program does not require the control of GHGs; rather it requires only monitoring and reporting of GHGs. 40 CFR part 98 provides the regulatory framework for the GHG Reporting Program. The GHG Reporting Program, which became effective on December 29, 2009, includes reporting requirements for facilities and suppliers in 34 subparts. For more detailed background information on the GHG Reporting Program, see the preamble to the final Part 98 rule establishing that program (74 FR 56260, October 30, 2009) and the preamble to the Part 98 rule expanding that program from 30 to 34 subparts (75 FR 39736, July 12, 2010).

1.2 Monitoring and Reporting Requirements for Injection and Geologic Sequestration of Carbon Dioxide: Subpart RR and UU

On April 12, 2010, EPA proposed this rule, amending the Greenhouse Gas (GHG) Reporting Program at 40 CFR part 98. Subpart PP of the GHG Reporting Program requires the reporting of carbon dioxide (CO_2) supplied to the economy. During the public comment period on the Part 98 rule establishing that requirement, EPA received many comments that CO_2 geologically sequestered should be considered in the GHG Reporting Program. (For further information on relevant comments received in 40 CFR part 98, subpart PP, see "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart PP: Suppliers of Carbon Dioxide" at EPA-HQ-OAR-2008-0508.) In the final rule promulgating 40 CFR part 98, subpart PP, EPA committed to taking action to collect such data in the near future.

This final rule amends 40 CFR part 98 to add reporting requirements covering facilities that conduct geologic sequestration of CO_2 (40 CFR part 98, subpart RR) and all other facilities that conduct injection of CO_2 (40 CFR part 98, subpart UU).[1] GS is the long-term containment of a CO_2 stream in subsurface geologic formations. This data will, among other things, inform Agency decisions under the CAA related to the use of carbon dioxide capture and geologic sequestration (CCS) for mitigating GHG emissions.

[1] EPA has moved all definitions, requirements, and procedures for facilities conducting CO_2 injection only (which both EPA and commenters have referred to as "Tier 1 " facilities for simplicity) into a new subpart, 40 CFR part 98, subpart UU, and retained all definitions, requirements, and procedures related to facilities conducting GS (which both EPA and commenters have referred to as "Tier 2" facilities for simplicity) in 40 CFR part 98, subpart RR.

Subpart RR information will enable EPA to monitor the growth and efficacy of GS (and therefore CCS) as a GHG mitigation technology over time and to evaluate relevant policy options. Furthermore, where enhanced oil and gas recovery (ER) projects are reporting under 40 CFR part 98, subpart RR, EPA will be able to evaluate ER as a non-emissive end use. Under 40 CFR part 98, subpart UU, EPA will be able to reconcile information obtained from this rule with data obtained from 40 CFR part 98, subpart PP on CO_2 supplied to the economy.

The rule was proposed by EPA on April 12, 2010. One public hearing was held on April 19, 2010, and the 60-day public comment period ended June 11, 2010. This final rule takes into consideration comments received during the comment period and finalizes the monitoring and reporting requirements for facilities conducting GS and all other facilities conducting CO_2 injection.

This final rule does not address whether data reported under 40 CFR part 98, subparts RR or UU will be released to the public or will be treated as CBI. EPA published a proposed rule on confidentiality determination on July 7, 2010 (75 FR 39094) that addressed this issue. In that action, EPA proposed which specific data elements may be released to the public and which would be treated as CBI. EPA received several comments on that proposal under that action, and is in the process of considering these comments.

SECTION 2
REGULATORY BACKGROUND

The intent of the GHG Reporting Program is to collect accurate and timely GHG data that can be used to inform future policies. Although the GHG Reporting Program is unique, EPA carefully considered other federal and state programs during development of the rule. The reporting program will supplement rather than duplicate other U.S. government GHG programs. We outline EPA's overall rulemaking approach, statutory authority, relationship to and coordination with the Safe Drinking Water Act Underground Injection Control Class VI rule, and summarize the relationship to the Interagency Task Force on Carbon Capture and Storage and other Federal GS initiatives, as well as the relationship to other geologic sequestration information collection and reporting efforts below.

2.1 EPA's Overall Rulemaking Approach

The GHG Reporting Program provides comprehensive and accurate data which will inform future climate change policies. Potential future climate policies include research and development initiatives, economic incentives, new or expanded voluntary programs, adaptation strategies, emission standards, a carbon tax, or a cap-and-trade program. Because we do not know at this time the specific policies that will be adopted, the data reported to the GHG Reporting Program should be of sufficient quality to support a range of approaches.

To these ends, we identified the following goals of the GHG Reporting Program:

- Obtain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations.
- Balance the rule coverage to maximize the amount of emissions reported while excluding small emitters.
- Create reporting requirements that are consistent with existing GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible.

This section presents the current regulatory context for Subparts RR and UU and illustrates the anticipated role of the final rule within the framework of the existing mandatory and voluntary programs.

2.2 Statutory Authority

EPA is promulgating this rule under its existing CAA authority; specifically, authorities provided in CAA section 114. As discussed in detail in Sections I.C and II.Q of the preamble to the Part 98 rule establishing the GHG Reporting Program (74 FR 56260, October 30, 2009), CAA section 114 provides EPA with broad authority to require information mandated by this rule, because such data will inform and are relevant to EPA's carrying out a wide variety of CAA provisions. Under CAA section 114(a)(1), the Administrator may require emissions sources, persons subject to the CAA, manufacturers of emission control or process equipment, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information as the Administrator requests for the purposes of carrying out any provision of the CAA (except for a provision of title II with respect to motor vehicles). EPA may gather information for a variety of purposes, including for the purpose of assisting in the development of implementation plans or of emissions standards under CAA section 111, determining compliance with implementation plans or such standards, or more broadly for "carrying out any provision" of the CAA.

2.3 Safe Drinking Water Act and UIC Regulations

The Agency maintains a high-level of coordination across EPA offices and regions on GS activities and regulatory development. EPA's Office of Air and Radiation (OAR) and Office of Water (OW) work closely to promote safe and effective implementation of GS technologies while ensuring protection of human health and the environment. OAR and OW have closely coordinated this rulemaking under CAA authority and the rulemaking under Safe Drinking Water Act (SDWA) authority establishing Federal requirements under the UIC program for Class VI wells.

EPA's UIC program was established in the 1970s to prevent endangerment of underground sources of drinking water (USDWs) from injection of various fluids, including CO_2 for ER, oil field fluids, water stored for drinking water supplies, and municipal and industrial waste. The UIC program, which is authorized by Part C of SDWA (42 U.S.C. 300h et seq.), is designed to prevent the movement of such fluid into USDWs by addressing the potential pathways through which injected fluids can migrate and potentially endanger USDWs. In 2008, EPA proposed to amend the UIC program to establish a new class of injection well — Class VI — to cover the underground injection of CO_2 for the purpose of GS, or long-term storage of CO_2 (73 FR 43492, July 25, 2008). For a summary of the UIC program and more details on the final UIC Class VI rule, please see the UIC Geologic Sequestration of Carbon Dioxide website: http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm.

EPA designed the reporting requirements under 40 CFR part 98, subpart RR with careful consideration of UIC requirements, including Class VI, to minimize overlap between the two programs. There are two areas of potential overlap. The first overlap is the requirement that owners or operators report the quantity of CO_2 injected. The UIC Class VI rule requires owners or operators to continuously monitor the amount of CO_2 injected and submit semi-annual reports on the monthly amount injected. The UIC program requires information on the amount injected to ensure appropriate CO_2 injection operations. Subpart RR requires facilities to collect data on the amount injected over a quarter and submit annual reports on the annual amount of CO_2 injected. Data on the amount of CO_2 injected is a component of the 40 CFR part 98, subpart RR mass balance approach used to quantify the amount of CO_2 sequestered. EPA determined that quarterly data collection and annual reporting under 40 CFR part 98, subpart RR was necessary in order to harmonize data with other subparts of the GHG Reporting Program. Facilities reporting under 40 CFR part 98, subpart RR may use flow meters used to comply with the flow monitoring and reporting provisions in their permit.

The second overlap is a monitoring plan for detecting air emissions. While requirements under the UIC program are focused on demonstrating that USDWs are not endangered as a result of CO_2 injection into the subsurface, requirements under the GHG Reporting Program through 40 CFR part 98, subpart RR will enable EPA to verify the quantity of CO_2 that is geologically sequestered and to assess the efficacy of GS as a mitigation strategy. Subpart RR achieves this by requiring facilities conducting GS to develop and implement a monitoring, reporting, and verification (MRV) plan[1] to detect and quantify leakage of injected CO_2 to the surface in the event leakage occurs and to report the amount of CO_2 geologically sequestered using a mass balance approach, regardless of the class of UIC permit that a facility holds.

The monitoring required by 40 CFR part 98, subpart RR for quantification purposes is complementary to and builds on UIC permit requirements. In particular, the UIC Class VI permit requires a comprehensive site characterization that includes an assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that GS wells are located in suitable formations. The UIC Class VI permit also requires computational modeling of the Area of Review, and a periodic re-evaluation of this Area of Review based on robust modeling and monitoring of the CO_2 stream, injection pressures, integrity of the injection well, groundwater quality and geochemistry, and the position of the CO_2

[1] The subpart RR MRV plan includes delineation of monitoring areas, identification and assessment of potential surface leakage pathways, a strategy for detecting and quantifying surface leakage of CO_2 if leakage occurs, an approach for establishing the expected baselines, and a summary of considerations for calculating site-specific variables for the mass balance equation, such as calculating CO_2 in produced fluids.

plume and pressure front throughout injection. These requirements can provide the basis for the MRV plan submitted to EPA for 40 CFR part 98, subpart RR. Therefore, EPA will accept a UIC Class VI permit to satisfy certain MRV plan requirements; however, the reporter must include additional information to outline how monitoring will achieve detection and quantification of CO_2 in the event surface leakage occurs.

The UIC Class VI rule also allows for surface air and soil gas monitoring at the discretion of the Director as a means of identifying CO_2 leaks that may pose a risk to USDWs and informing emergency notification of a UIC Class VI owner or operator and UIC Director in the event of a USDW endangerment. If the Director determines that it is appropriate to require surface air or soil gas monitoring for USDW protection, the Director must approve the use of monitoring employed under 40 CFR part 98, subpart RR so long as the owner or operator is able to demonstrate USDW protection pursuant to requirements at §146.90(h)(3).

EPA has determined that the requirements of these two rules complement one another by concurrently ensuring USDW protection, as required under SDWA, and requiring reporting of CO_2 surface emissions under 40 CFR part 98, subpart RR. EPA is committed to working closely within the agency to coordinate implementation of the UIC and GHG Reporting programs, reduce burden on reporters, provide timely access to verified emissions data, establish mechanisms to efficiently share data, and harmonize data systems to the extent possible.

In the cost analysis conducted for this rule, EPA has assumed that for saline sequestration projects these requirements are in the baseline, and consequently estimated incremental costs associated with surface detection and quantification of CO_2. Further detail on the cost analysis is available in sections 4 and 5 of this document. EPA is committed to working closely within the agency to coordinate implementation of the UIC and GHG Reporting programs, reduce burden on reporters, provide timely access to verified emissions data, establish mechanisms to efficiently share data, and harmonize data systems to the extent possible.

2.4 Relationship to the Interagency Task Force on Carbon Capture and Storage and Other Federal GS Initiatives

On February 3, 2010, President Obama established an Interagency Task Force on Carbon Capture and Storage (CCS Task Force). The CCS Task Force, co-chaired by EPA and the Department of Energy (DOE), developed a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years, with a goal of bringing five to ten commercial demonstration projects online by 2016. The CCS Task Force's plan was delivered to President Obama in August 2010.

The CCS Task Force explored incentives for commercial CCS adoption and addressed financial, economic, technological, legal, institutional, social, or other barriers to deployment. For example, the CCS Task Force examined Federal regulatory activities that address the safety, efficacy, and environmental soundness of GS. The CCS Task Force also considered how best to coordinate existing administrative authorities and programs, including those involving international collaboration, as well as identified areas where additional administrative authority may be necessary. The CCS Task Force recommended that EPA finalize this rule. For more information, please see the CCS Task Force website: http://www.epa.gov/climatechange/policy/ccs_task_force.html.

2.5 Relationship to Other Geologic Sequestration Information Collection and Reporting Efforts

EPA reviewed and took into account several existing domestic and international reporting and monitoring programs in designing this rule. For additional information, please see Section I.F of the notice of proposed rulemaking (75 FR 18581, April 12, 2010).

Also as discussed in the notice of proposed rulemaking, EPA notes that the Internal Revenue Service (IRS) published IRS Notice 2009-83 (available at: http://www.irs.gov/irb/2009-44_IRB/ar11.html#d0e1860) to provide guidance regarding eligibility for the Internal Revenue Code section 45Q credit for CO_2 sequestration, computation of the section 45Q tax credit, reporting requirements for taxpayers claiming the section 45Q tax credit, and rules regarding adequate security measures for secure GS. As clarified in the IRS guidance, taxpayers claiming the section 45Q tax credit must follow the appropriate UIC requirements. The guidance also clarifies that taxpayers claiming section 45Q tax credit must follow the MRV procedures that are being finalized under 40 CFR part 98, subpart RR in this final rule.

SECTION 3
SUMMARY OF FINAL RULE: SUBPART RR AND UU

Facilities that conduct geologic sequestration are subject to 40 CFR part 98, subpart RR. All other facilities that inject CO_2 underground are subject to 40 CFR part 98, subpart UU. If you report under 40 CFR part 98, subpart RR for a well or group of wells, you are not required to report under 40 CFR part 98, subpart UU for that well or group of wells.

3.1 Subpart RR

3.1.1 Source Category Definition

The 40 CFR part 98, subpart RR source category consists of any well or group of wells that inject a CO_2 stream for long-term containment into a subsurface geologic formation.[1] All wells permitted as Class VI by the UIC program meet the definition of this source category. Facilities conducting ER are not subject to 40 CFR part 98, subpart RR unless they choose to opt-in to the requirements of this subpart or hold a UIC Class VI permit.

R&D projects are exempt from reporting requirements under 40 CFR part 98, subpart RR provided they meet the eligibility requirements. A project is eligible for the exemption if it investigates or will investigate practices, monitoring techniques, or injection verification, or if it is engaged in other applied research that focuses on enabling safe and effective long-term containment of a CO_2 stream in subsurface geologic formations, including research and injection tests conducted as a precursor to a larger more permanent long-term storage operation. Small and large-scale projects meeting the criteria for an exemption, such as the current Regional Carbon Sequestration Partnership projects supported by the Office of Fossil Energy at the Department of Energy (DOE), would be considered R&D for the purposes of this exemption from reporting for the duration of the R&D activity. Other DOE supported GS R&D projects may also satisfy the eligibility requirements for the exemption. In addition, short duration CO_2 injection projects conducted to identify local amenability to long term storage will be exempted from 40 CFR part 98, subpart RR for the duration of such injection testing. This includes cases where an operator is using a short duration CO_2 injection test to assess local geologic conditions and validate the injectivity potential of a particular site prior to developing that site for commercial scale geologic storage of carbon dioxide. Demonstration projects can apply for the

[1] Note that R&D projects that are exempted from subpart RR report under Subpart UU – see discussion below.

exemption, but will be measured against the same criteria established in 40 CFR 98.440(d). Projects that are not R&D projects, such as commercial GS operations, are not eligible for the exemption.

To receive an R&D exemption, the project representative must submit to the Administrator information on the planned duration of CO_2 injection for research, the planned annual CO2 injection volumes during this time period, the purposes of the project, the source and type of funding for the project, and the class and duration of UIC permit, or, for an offshore facility not subject to SDWA, a description of the legal instrument authorizing GS.

The Administrator will determine if a project meets the definition of research and development project within 60 days of receipt of the submission of a request for exemption. In making this determination, the Administrator will take into account any information that the reporter submits demonstrating that the planned duration of CO_2 injection for the project and the planned annual CO_2 injection volumes during the duration of the project are consistent with the purpose of the research and development project. This rule allows for administrative appeals of the Administrator's R&D determination, as provided for in 40 CFR part 78.

Facilities that qualify for a GS R&D exemption from 40 CFR part 98, subpart RR are not exempted from any other source category of the GHG Reporting Program including 40 CFR part 98, subpart UU. For other source categories of the GHG Reporting Program, R&D is defined at 40 CFR 98.6.

3.1.2 Subpart RR Reporting Threshold

All facilities that meet the 40 CFR part 98, subpart RR source category definition must report (i.e., there is no reporting threshold). However, reporters that receive a subpart RR R&D exemption are no longer subject to subpart RR, but rather report CO_2 received under subpart UU. The cease reporting provisions of §98.2(i) do not apply to subpart RR. Rather, once a facility is subject to the requirements of this subpart, including facilities that opt-in to 40 CFR part 98, subpart RR, the owner or operator must continue for each year thereafter to comply with all requirements of this subpart, including the requirement to submit annual GHG reports, until the Administrator has issued a final decision on an owner or operator's request to discontinue reporting. The request to discontinue reporting must include either a copy of the applicable UIC program Director's authorization of site closure, or a demonstration that the injected CO_2 stream is not expected to migrate in a manner likely to result in surface leakage. Before the reporter can discontinue reporting, but after injection has ceased, EPA expects that in most cases there will be minimal burden in monitoring and reporting unless a surface leak is detected.

3.1.3 Subpart RR GHGs to Report

Facilities covered by this source category must report the mass of CO_2 received; the mass of CO_2 injected; the mass of CO_2 produced (i.e., mixed with produced oil, gas, or other fluids); the mass of CO_2 emitted from surface leakage; the mass of CO_2 equipment leaks and vented CO_2 emissions from sources between the injection flow meter and the injection wellhead or between the production flow meter and the production wellhead; and the mass of CO_2 sequestered in subsurface geologic formations (this is calculated from the other quantities).

3.1.4 Subpart RR GHG Calculations and Monitoring

Facilities covered by this source category must calculate the annual mass of CO_2 received. Starting from the date specified in the EPA-approved MRV plan, facilities must also use a mass balance approach to calculate the mass of CO_2 geologically sequestered. First, facilities must calculate the annual mass of CO_2 injected. From the annual mass of CO_2 injected, facilities must subtract the mass of CO_2 emitted from surface leakage, using the site-specific procedures in their MRV plan, and the mass of CO_2 emitted as equipment leaks or vented emissions from applicable surface equipment, using the procedures specified in 40 CFR part 98, Subpart W of the GHG Reporting Program. All GS projects with equipment leak or vented emissions from surface equipment applicable to the GS mass balance equation should use the procedures specified in subpart W, regardless of whether such projects are associated with the oil and gas industry. Facilities that are producing, oil, gas, or other fluids must additionally subtract the mass of CO_2 produced. Calculation procedures are provided at 40 CFR 98.443.

3.1.5 Subpart RR Data Reporting

In addition to the information summarized at "Subpart RR GHGs to Report" in this section of the preamble, facilities must report the source of the CO_2 received and the cumulative amount of CO_2 geologically sequestered since the facility first reported under subpart RR. All facilities must also report concentration, facilities using mass flow meters must report mass flow information, facilities using volumetric flow meters must report volumetric flow information, and facilities using containers must measure the mass or volume of the containers. They are required to report a description of the monitoring program that was implemented, including descriptions of monitoring anomalies and surface leakage, if any. Finally, for EPA verification purposes, they are required to report for each injection well the class of UIC permit and well identification number used for the UIC permit.

Subpart RR requires reporting of CO_2 equipment leaks and vented CO_2 emissions to the extent they are a component of the GS mass balance. Subpart RR does not require reporting of CO_2 equipment leaks and vented CO_2 emissions from all surface equipment located within the facility (e.g., operational emissions not related to the CO_2 being injected) ; however, GS projects that produce oil or natural gas may be required to report CO_2 equipment leaks and vented CO_2 emissions in the petroleum and natural gas system subpart, 40 CFR part 98, subpart W as part of either offshore or onshore petroleum and natural gas production.

3.1.6 Subpart RR Recordkeeping

Facilities must retain quarterly records of CO_2 received; injected CO_2; produced CO_2; CO_2 emitted by surface leakage; CO_2 emitted as equipment leaks and vented emissions from equipment located on the surface between the flow meter used to measure the injection quantity and the injection wellhead and between the flow meter used to measure the production quantity and the production wellhead; and any other records as outlined for retention in the facility MRV plan for 3 years per 40 CFR 98.3(g).

3.1.7 Subpart RR Administrative Appeals

Under this final rule, final decisions of the Administrator under part 98, subpart RR are appealable to EPA’s Environmental Appeals Board under the regulations that are set forth in part 78 (40 CFR part 78). Part 78 is revised to accommodate such appeals. Specifically, the list in 40 CFR 78.1 of the types of final decisions that can be appealed under 40 CFR part 78 is expanded to cover final decisions of the Administrator under 40 CFR part 98, subpart RR. This list includes, but is not limited to, the following specific types of decisions under subpart RR, e.g., the determination of eligibility for an R&D exemption under 40 CFR 98.440(d)(4), the approval or disapproval of a request for discontinuation of reporting under 40 CFR 98.441(b)(2), and the approval or disapproval of a MRV plan under 40 CFR 98.448(c).

Further, 40 CFR 78.3 is revised to allow for petitions for administrative appeal of decisions of the Administrator under 40 CFR part 98, subpart RR. Under the general approach in the existing part 78, an “interested person” (in addition to the official representative of owners and operators involved in a matter) may petition for an administrative appeal of a final decision of the Administrator. The “interested person” definition, which is located in part 72 of the Acid Rain Program regulations, is expanded to take into account final decisions of the Administrator under part 98. In particular, EPA is revising the “interested person” definition by replacing specific references to the Acid Rain Program and draft permits with broader references to any decision by the Administrator and the Administrator’s process of making that decision. As a result of this revision and the revisions of 40 CFR part 78, a person who does not own or operate a facility covered by a final decision under 40 CFR part 98, subpart RR will need to submit his or her name to be included by the Administrator on an “interested persons list” in order to be able to appeal -- by filing a petition for an administrative appeal -- that final decision.

In addition, 40 CFR 78.4 is expanded to state that filings on behalf of owners and operators of a facility subject to 40 CFR part 98, subpart RR must be signed by the designated representative of the owners and operators.

3.2 Subpart UU

3.2.1 Subpart UU Source Category Definition

The 40 CFR part 98, subpart UU source category consists of any well or group of wells that inject a CO_2 stream into the subsurface. This includes any wells used to enhance oil and gas recovery and GS R&D projects that are exempted from 40 CFR part 98, subpart RR monitoring and reporting requirements. If you report under 40 CFR part 98, subpart RR for a well or group of wells, you are not required to report under 40 CFR part 98, subpart UU for that well or group of wells.

3.2.2 Subpart UU Reporting Threshold

All facilities that inject CO_2 underground must report under this subpart, regardless of the amount of emissions from the facility or the amount of CO_2 injected. Reporters can cease subpart UU reporting pursuant to the provisions at 40 CFR 98.2(i) that allow facilities to cease GHG reporting to EPA; with respect to subpart UU, any reference to CO_2 emissions in 40 CFR 98.2(i) means CO_2 received.

3.2.3 Subpart UU GHGs to Report

Facilities covered by this source category must report the annual mass of CO_2 received.

3.2.4 Subpart UU GHG Calculations and Monitoring

Facilities covered by this source category must calculate the annual mass of CO_2 received using the calculation procedures for either mass or volumetric flow meters. Where CO_2 is received in containers, facilities must use the calculation procedures for determining the mass or volume of contents in containers.

3.2.5 Subpart UU Data Reporting

In addition to reporting the mass of CO_2 received, facilities must report the source of the CO_2. All facilities must also report concentration, facilities using mass flow meters must report mass flow information, facilities using volumetric flow meters must report volumetric flow information, and facilities using containers must measure the mass or volume of the containers.

3.2.6 Subpart UU Recordkeeping

Facilities must retain quarterly records of any CO_2 received for 3 years per 40 CFR 98.3(g).

3.3 Summary of Major Changes Since Proposal

The major changes in this rule since the original proposal are identified in the following list. The rationale for these and any other significant changes to the rule can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subparts RR and UU: Injection and Geologic Sequestration of Carbon Dioxide."

- EPA has moved all definitions, requirements, and procedures for facilities conducting CO_2 injection only (which both EPA and commenters have referred to as "Tier 1" facilities for simplicity) into a new subpart, 40 CFR part 98, subpart UU, and retained all definitions, requirements, and procedures related to facilities conducting GS (which both EPA and commenters have referred to as "Tier 2" facilities for simplicity) in 40 CFR part 98, subpart RR.

- EPA has removed the requirement that facilities report the amount of CO_2 injected in 40 CFR part 98, subpart UU (Tier 1) reporting requirements but retained requirements that facilities subject to this subpart report the amount of CO_2 received and the source of CO_2 if known

- EPA has established procedures for calculating CO_2 received in containers.

- In 40 CFR part 98, subpart RR, EPA has established eligibility requirements for a GS R&D project to be exempt from 40 CFR part 98, subpart RR.

- In 40 CFR part 98, subpart RR, EPA has retained the requirement that facilities report the equipment leaks and vented emissions reporting requirement for surface equipment that could be included in the GS mass balance but removed the requirement for reporting equipment leaks and vented emissions for all other surface equipment.

- In 40 CFR part 98, subpart RR, EPA has added an MRV plan requirement for the delineation of the areas that will be monitored.

- In 40 CFR part 98, subpart RR, EPA has clarified the requirements for an addendum to the annual report and renamed it the monitoring report.

- EPA has amended 40 CFR part 78 to include administrative appeals procedures for EPA decisions made under 40 CFR part 98, subpart RR, such as decisions relating to eligibility for the R&D exemption under 40 CFR 98.440(d)(4), decisions relating to a request for discontinuation of reporting under 40 CFR 98.441(b)(2), or MRV plan decisions under 40 CFR 98.448(c).

SECTION 4
ENGINEERING COST ANALYSIS

4.1 Introduction

Using available industry and EPA data to characterize conditions at affected sources, EPA estimated the costs of complying with final rule. Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility, and the associated costs were estimated.

4.2 Overview of Cost Analysis

The costs of complying with the rule will vary from one facility to another, depending on the nature of the CO_2 injection activities (GS or non-GS), the MRV plan selected, existing monitoring, recordkeeping, and reporting activities at the facility, etc. The costs include labor costs for performing the monitoring, recordkeeping, and reporting activities necessary to comply with the rule, as well as capital costs related to the implementation of monitoring activities outlined in the MRV plan for GS sites. All costs referred to in this section are reported in 2008 dollars.

We first provide a general overview of baseline reporting and GS activities. This is followed by detail on the cost components associated with this information collection; labor costs (i.e., the cost of labor by facility staff to meet the information collection requirements of the rule); and capital and operating and maintenance costs (e.g., the cost of purchasing and installing monitoring equipment or contractor costs associated with providing the required information).

In section 4.10, we summarize the first year and subsequent year costs by facility and subpart (Table 4-10) that are used in the economic analysis presented in section 5.

4.3 Baseline Reporting

4.3.1 Introduction

The Environmental Protection Agency developed cost scenarios for reporting of CO_2 injection and GS. These rules can affect the number and type of monitoring equipment installed at the sites and the type and frequency of tests and surveys conducted at the sites. In creating new EPA regulations, a unit cost analysis and the total cost impact of each of the final regulations is required by federal law. This provides a basis for a full evaluation of the incremental costs of the final rule. The purpose of this section is to present the "activity baseline," which describes the number and types of injection and GS sites that could be subject to the rule and the volume of CO_2 injections that would be expected.

Through the practice of geological sequestration, CO_2 can potentially be sequestered in underground formations worldwide for thousands of years. Although commercial geologic sequestration of CO_2 has not yet begun in the U.S., several projects such as Sleipner in the North Sea, In Salah in Algeria, and Weyburn in Alberta have achieved success in recent years. CO_2 at these sites is being sequestered, and technologies to monitor the process have proved effective. In the U.S., the Department of Energy is supporting approximately 25 sequestration pilot projects around the country. DOE also has plans to start a number of relatively large scale pilot projects within coming years.

Geologic sequestration in the U.S. will likely occur in a range of different geologic settings including: saline reservoirs, oil and gas reservoirs, coal seams, and others. For purposes of this economic analysis, the costs of specific aspects of geologic sequestration were specified on the basis of cost per well, per square mile, per sample, or other basis for each project. In addition, "type cases" were developed for each reservoir type including, in some instances, two sizes of injection projects for pilot and commercial-size project scales. These include the typical parameters (e.g. number of monitoring wells and average well depth) for each type of project, allowing for estimation of total cost per project. In the cost analysis that appears in Chapter 5, a base case is created assuming relevant monitoring costs are only that which is required under the UIC rules. Then three cost scenarios for reporting from geologic sequestration sites are evaluated in terms of technologies and practices and their costs.

4.3.2 Data Sources

In order to evaluate the total costs in the U.S. of the final regulations, it is necessary to establish an activity baseline forecast of the sequestration activity to which the final regulation applies. The appropriate forecast for this analysis is the level of GS activity that would be expected even in the absence of future climate change legislation. While climate change legislation is currently being debated in Congress, no legislation has been enacted. Even in the absence of national climate legislation, sequestration activity in the U.S. is planned including:

- Research and Development (R&D) projects,
- FutureGen Sequestration Site, and
- Commercial Sequestration Projects Related to State and Regional Incentive Programs (in part, funded by DOE)

4.3.3 Published Data on CO_2 Sequestration Projects

4.3.3.1 Planned R&D Projects

The Department of Energy has funded an extensive research effort into geologic sequestration in the U.S. The project is a collaborative effort with seven regional partnerships. The research effort is managed by the National Energy Technology Laboratory in Morgantown, West Virginia. The program has two major components: Core R&D and Demonstration and Deployment.

According to DOE, the goal is to "develop by 2012 systems that will achieve 90% capture of CO_2 at less than a 10 percent increase in the cost of energy services and retain 99 percent sequestration permanence." [4]

The field component of the sequestration research is being carried out by seven regional partnerships. These partnerships were formed in 2003 and represent consortia of private industry and government agencies. This effort is tasked with determining the most suitable technologies, regulations, and infrastructure needs for capture and sequestration.

There are three phases to the work being carried out by the partnerships:

- Characterization (2003-2005)
- Validation (2005-2009)
- Deployment (2009-2017)

The Characterization Phase involved the geologic analysis that resulted in the development of a National Carbon Sequestration Database and Geographic Information System (NATCARB). The Validation Phase is currently active and involves such activities as validation of reservoir simulation methods, data collection for capacity and injectivity, and demonstration of monitoring technologies. Also being researched are well completion methods, operations, and abandonment approaches.

The Deployment Stage involves the construction and operation of 8 significant sequestration projects. These projects are consistent with the Energy Independence and Security Act of 2007 (EISA), under Title VII, Sec. 702, which requires DOE to conduct at least 7 large scale sequestration field tests greater than one million tons of CO_2 each. These tests are designed

[4] *Direct Carbon Sequestration: Capturing and Storing Carbon Dioxide*, Congressional Research Service, report RL33801, September, 2007.

to fully evaluate the potential for commercial scale operations in a range of geological settings. The tests are planned to have an injection period of up to four years, followed by a lengthy monitoring period. This phase is designed to evaluate the practical aspects of large scale injection over a prolonged period of time.

A great deal of progress has been made in the areas of site characterization and monitoring. The next major phase of the DOE research effort is to provide funding support for a number of commercial scale sequestration operations with injections of up to one million tons per year.

Sequestration Related to State and Regional Incentive Programs

A number of states or regions have adopted or plan to adopt regulations to address carbon dioxide and/or greenhouse gas emissions. Most allow for regulated sources of emissions to meet compliance requirements through the use of offsets. Although geologic sequestration goals or criteria may not be specified in each case, the potential exists for sequestration activities to become an accepted and more prevalent way of meeting greenhouse gas reductions.

The programs or state legislation initiatives are generally in the early stages, and there is considerable uncertainty in terms of which projects will proceed, and on what schedule. ICF has researched the CSLF (Carbon Sequestration Leadership Forum) online database and the MIT online database in our analysis of non-DOE projects. It should be noted, that in these databases, there are several projects for which startup date and/ or planned injection volumes are not specified.

Laboratory Research

Over the past several years, DOE and the regional partnerships have carried out an effort to assess and characterize the CO_2 sequestration capacity and potential of the U.S. This effort has resulted in the publication of a large amount of information on potential by geologic setting and basin or state. A large amount of GIS data has also been compiled on the geology of sequestration potential.

In 2008, DOE published the most recent version of the NATCARB (National Carbon) Atlas. [5] This publication contains maps and data tables documenting their assessment of

---

[5] *Carbon Sequestration Atlas of the United States and Canada,* 2008, U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV.

sequestration potential in the U.S. Much of the data behind the NATCARB atlas are either available in GIS form or will eventually be made available.

4.3.4 Hydrogeologic Settings

Geologic sequestration may take place in a number of settings and lithologies. These include:

- Non-basalt saline reservoirs
- Depleted gas fields
- Depleted and abandoned oil fields
- Enhanced oil recovery (ER)
- Enhanced coalbed methane recovery

For the purposes of analyzing this rule, we will focus on the settings that are most likely affected by the rule, which includes saline reservoirs and oil and gas fields.

4.3.4.1 Non-Basalt Saline Reservoirs

Most significant sedimentary basins in the U.S. contain regionally significant saline formations that are potential sequestration reservoirs. These are typically sandstone lithologies with good porosity, containing formation waters of greater than 10,000 mg/L total dissolved solids. Salinity may be as high as several times that of seawater. Thus, the water is unsuitable for drinking or agriculture. Saline reservoirs dominate the assessed potential of the U.S. and worldwide. In addition, because of their wide geographic distribution in the U.S., saline reservoirs are often in close proximity to CO_2 sources, minimizing pipeline transport distance. Saline reservoirs represent the vast majority of U.S. sequestration potential (approximately 89 percent of total U.S. capacity). [6] It is very likely that saline reservoirs will play a prominent role in future geologic sequestration.

Sequestration in saline reservoirs has been shown to be effective. The Sleipner field in the North Sea is the first commercial-scale saline reservoir project. Carbon dioxide is separated from the gas stream and re-injected into a reservoir at about 800 meters depth. The rate of

[6] 2007 ICF assessment developed using DOE Atlas volumes and supplementing in several categories.

injection is 2,700 tons per day or about one million tons per year. [7] It is anticipated that about 20 million tons will eventually be stored. At Sleipner, the plume has been monitored effectively. [8]

DOE has extensively studied saline reservoirs for sequestration. Projects include the Frio Brine pilot in the Texas Gulf Coast and the Mount Simon Sandstone in the Illinois Basin. [9] The Mount Simon is known to have excellent sequestration potential because of its regional thickness and reservoir characteristics, and because it has been used extensively for natural gas sequestration in the Midwest.

4.3.4.2 Depleted Gas Fields and Oil Fields

Depleted gas and oil fields can be excellent candidates for CO_2 sequestration. These represent known structures that have trapped hydrocarbons over geologic time, thus proving the presence of an effective structure and seal above the reservoir. These fields have also been extensively studied, there is a large amount of well log and other data available, and the field infrastructure is already in place. This infrastructure could in some cases be utilized in sequestration. A potentially problematic aspect of using depleted fields for sequestration is the presence of a large number of existing wellbores, which can provide leakage pathways. Typically, oil fields are developed with a closer spacing than gas fields, resulting in a larger number of existing wells per unit area than in gas fields.

The In Salah Field in Algeria was the world's first project in which CO_2 is injected at commercial scale into a gas reservoir. However, in this case, the gas is injected downdip in an actively producing gas reservoir. This differs from an abandoned gas reservoir scenario in which the gas field is no longer producing.

4.3.4.3 Enhanced Recovery of Oil and Gas

Under certain reservoir and fluid conditions, CO_2 can be injected into an oil reservoir in a process called miscible CO_2 enhanced oil recovery. The effect of the CO_2 is to mobilize the oil

---

[7] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[8] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[9] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss*, Interstate Oil and Gas Compact Commission, January, 2005.

so that it can move more readily to the production wells. As the oil is produced, part of the injected CO_2 is produced with the oil. This CO_2 is then separated and re-injected.

In the U.S. most CO_2 ER projects are located in the Permian Basin of West Texas, where projects have been in place for several decades. The source of most of the CO_2 is natural CO_2 from several fields in Colorado and New Mexico. [10] Some of the injected CO_2 is from gas processing or other sources. The current volume of CO_2 injected for CO_2 ER is about 2.2 billion cubic feet per day.

In 2005, CO_2 ER operations produced approximately 237,000 barrels of oil per day in the U.S. About 180,000 barrels per day of that occurred in West Texas, with most of the rest produced in the Rockies, Mid-Continent, and Gulf Coast. [11]

The development of CO_2 ER projects has resulted in a great deal of knowledge about the process and injection well and other technologies have matured and are well understood. In addition, it is estimated that more than 3,500 miles of high pressure (>1,300 psi) CO_2 pipelines have been built to accommodate these operations. [12]

At the Weyburn Field in Saskatchewan, CO_2 from the Dakota Gasification Facility in North Dakota is injected into an oil reservoir for ER and monitoring of CO_2 sequestration. Over the 25 year life of this project, it is expected that about 18 million tons of CO_2 will be sequestered.

4.3.4.4 Enhanced Coalbed Methane Recovery

CO_2 can potentially be sequestered in coalbeds through the process of adsorption. CO_2 injected as a gas into a coal bed will adsorb onto the molecular structure and be sequestered.

Methane is naturally adsorbed onto coalbeds and coalbed methane now represents a significant percentage of U.S. natural gas production. Major coalbed methane production areas include the San Juan Basin of northwestern New Mexico and southwestern Colorado, the Powder River Basin of eastern Wyoming, and the Warrior Basin in Alabama.

---

[10] *The Economics of CO_2 Storage*, Gemma Heddle, Howard Herzog, and Michael Klett, Laboratory for Energy and the Environment, Massachusetts Institute of Technology, August, 2003.
[11] Oil and Gas Journal, April 17, 2006.
[12] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss*, Interstate Oil and Gas Compact Commission, January, 2005.

The concept of enhanced coalbed methane recovery is based upon the fact that coalbeds have a greater affinity for CO_2 than methane. Thus, when CO_2 is injected into the seam, methane is liberated and the CO_2 is retained. This additional methane represents enhanced gas recovery.

Depending upon depth and other factors, coalbeds may be mineable or unmineable. Because the process of mining the coal would release any stored CO_2, only unmineable coals are assessed as representing permanent CO_2 sequestration. [13]

4.3.4.5 Other Hydrogeologic Settings

Basalt flows such as those of the Columbia River Basalts in the Pacific West, are believed to have the potential for permanent CO_2 sequestration. The sequestration process is geochemical trapping, in which the CO_2 reacts with silicates in the basalt to form carbonate minerals. [14] While research is being carried out on basalt, it is considered unlikely that any commercial scale sequestration will occur in the foreseeable future due to the unconventional geology and likely difficulty in monitoring.

The potential to sequester CO_2 in organic shale formations is based upon the same concept as that of coal beds. CO_2 will adsorb onto the organic material, displacing methane. Gas shales have recently emerged as a major current and future source of gas production in the U.S. These include the Barnett Shale in the Fort Worth Basin, the Fayetteville and Woodford Shales in the Arkoma Basin, and the Appalachian Devonian Shale. These Devonian and Mississippian age organic shale formations represent tremendously large volumes of rock. To date little research has been done on enhanced gas recovery with organic shales. However, should it prove technically feasible, the U.S. could become one of the major areas worldwide for this type of sequestration.

4.3.5 Formation Capacity

4.3.5.1 Current DOE Assessment of Sequestration Potential

Through the regional sequestration partnerships, DOE has developed a new national assessment of sequestration potential. As evaluated by ICF, the DOE Lower-48 total is 8,179 gigatonnes (Gt) of CO_2. The range of uncertainty is 3,508 to 12,850 Gt. Most of the

---

[13] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss*, Interstate Oil and Gas Compact Commission, January, 2005.

[14] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

assessment is attributed to saline reservoirs). This assessment is much larger than the prior assessments also shown on the table.

4.3.6 Geologic Sequestration Rule Activity Baseline

Based upon the above information on what is anticipated for R&D projects, FutureGen, and state programs, an activity baseline forecast of sequestration activity has been developed. Because of the uncertainty in which existing ER project might come under subpart RR, three scenarios have been created and are shown as Tables 4-1. The first scenario assumes that no existing CO_2 ER projects choose to report as facilities conducting GS. The second scenario assumes that all CO_2 ER projects from anthropogenic sources (7 million metric tons per year coming primarily from natural gas processing plants) choose to report as facilities conducting GS. The third scenario assumes that all projects from anthropogenic CO_2 sources plus one-half of the remaining CO_2 flood projects choose to report as facilities conducting GS. This third scenario adds up to 23.4 million metric tons per year injected of new (i.e., ignoring recycled volumes) CO_2. These scenarios were chosen to represent a realistic range of ER projects that might opt-in under subpart RR. The lower bound is what one might expect participation to be given the lack of comprehensive climate legislation that provides a financial incentive for sequestration. The upper bound recognizes the fact that not all ER projects are amenable to sequestration due to reservoir depths and other considerations.

The most comprehensive source of information on US ER projects is the annual survey conducted by the Oil and Gas Journal. The 105 projects listed in the Oil and Gas Journal 2007 ER survey were grouped by CO_2 source type – natural or anthropogenic. CO_2 use was allocated to the projects supplied by each source based on oil production. Anthropogenic sources were well defined for ER projects in Michigan (Antrim Gas Processing Plant), Wyoming/Colorado (LaBarge/Shute Creek Gas Processing Plant), central Oklahoma (Enid Fertilizer Plant) and Kansas (US Energy Partners, Russell Kansas Ethanol Plant) from geographic proximity and information in published literature. Natural CO_2 production from the Jackson Dome in Mississippi was allocated to the 15 projects in Mississippi and Louisiana based on geographic proximity and information in published literature. Anthropogenic CO_2 from the Val Verde Gas Plant in Texas is mixed with CO_2 from natural sources and distributed to several fields in the Permian Basin so there was not a clear delineation of which projects were served by anthropogenic gas from the Val Verde plant. To estimate the number of facilities served by Val Verde, the total CO_2 use in the Permian Basin from natural sources and Val Verde production was summed and the percent of Val Verde production was prorated among the 66 projects in the Permian Basin. Val Verde CO_2 production represents 5.4 % of the total CO_2 used in the Permian Basin, therefore, the equivalent of approximately 4 projects in the Permian Basin are estimated to use anthropogenic CO_2 from Val Verde. For this analysis 2007 CO_2 production data for natural and anthropogenic sources was taken from the (1990-2007) Inventory of U.S. Greenhouse Gas Emissions and Sinks, and totaled 2.1 bcf/day which differs from the published DOE estimate of 2.6 bcf/day.

Based on the number of projects active in 2007, anthropogenic sources provide approximately 18% of the mass of CO_2 used in ER projects in the US, and represent approximately 27 % of the CO_2 ER projects. These projects result in the additional production of more than 13 million barrels of oil annually. If only ER projects supplied by anthropogenic sources opted into the reporting program approximately 29 projects would be included. If all the ER projects supplied by anthropogenic sources, and half of the projects using natural sources opted into the reporting program approximately 67 projects would report, representing 1.2 bcf/day (23.4 million metric tons per year) or 59% of all CO_2 ER use.

Table 4-1. Baseline Assumptions: Subpart RR/UU

Type and Subpart	Reference Case	Metric Tons CO_2 Received per Year	Assuming All Anthropogenic Project Opt-in	Metric Tons CO_2 Received per Year	Assuming All Anthropogenic and 50 Percent of Other CO_2 Projects Opt-in	Metric Tons CO_2 Received per Year
R&D (RR)	9[a]	5,320,000	9 [a]	5,320,000	9 [a]	5,320,000
Facilities Conducting GS (Saline) (RR)	1	1,842,885	1	1,842,885	1	1,842,885
Facilities Conducting GS (ER) (RR)	0	0	16	6,972,040	48	23,543,741
Facilities Conducting CO_2 Injection (No GS) (UU)[b]	92[a]	48,735,442[b]	76 [a]	41,763,402	44 [a]	25,191,701
Total Projects	93[c]	50,578,327[c]	93[c]	50,578,327	93 [c]	50,578,327

[a]The 9 R&D facilities facilities are assumed to apply for a waiver and incur approximately $4,000 in costs under subpart RR. The 9 R&D will subsequently be covered under subpart UU (83 + 9 = 92) and incur the additional $4,000 in costs for subpart UU.
[b]Includes UIC Class II ER facilities.
cTotals are adjusted to avoid double counting of 9 R&D facilities. See footnote a.

4.3.6.1 Sources of Uncertainty

The activity baseline forecast of sequestration activity represents our best estimate of what will likely occur in the absence of national climate change legislation. As with any forecast, there are sources of uncertainty. Categories of uncertainty include:

- Number and timing of R&D projects and number of years of injection
- Number and timing of FutureGen projects and number of years of injection
- Number and timing of State Incentive projects and number of years of injection
- Average injection rates
- Number of ER projects that will be covered

Of the three categories of project, the least uncertainty is associated with the R&D projects. These projects have been funded and are expected to proceed at close to the announced schedule.

The DOE FutureGen project site has been chosen (Illinois) but there is still uncertainty about timing and injection volumes.

Given the number of state and regional initiatives underway it is very likely that projects related to state incentives will be initiated.

The largest uncertainty over the timeframe of the activity baseline is what may occur at the national level in terms of climate change legislation. However, any costs associated with potential future national climate policy cannot be attributed to this subpart currently under consideration. The activity baseline presented in this document is expressly for the purpose of evaluating the costs of the subpart RR proposal under existing climate change policies.

4.4 Reporting Costs

4.4.1 Introduction

The purpose of this section is to present the unit cost estimates for the equipment and services that might be required to comply with the CO_2 Injection and GS Reporting rule and the total incremental annual cost of compliance. A base case is created assuming monitoring costs are only that which is required under the UIC rules. Then three cost scenarios for reporting from geologic sequestration sites are evaluated in terms required technologies and practices and their costs.

4.4.2 Cost Assumptions and Methodology

No comprehensive source has been identified that provides detailed summaries of the full range of sequestration project cost components. Estimates of the costs of monitoring equipment, the number of stations required, and the cost of ongoing monitoring are based upon analysis of available literature and recent presentations by government and academic research groups and quotations from vendors. Some specific monitoring costs were obtained at a recent industry meeting sponsored by the Groundwater Protection Council.[15]

The costs reported here include capital and operating and maintenance (O&M) including labor costs. They are based on hypothetical or pro-forma sites for various types of projects such as saline formation R&D GS projects, saline formation commercial GS projects, and ER GS projects. The geologic and engineering assumption for these pro-forma projects are the same as those used by the EPA Office of Water in the final rule, Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells, or the UIC Class VI final rule for CO_2 injection wells[16], and are shown below in Table 4-2.

[15] Ground Water Protection Council Meeting, New Orleans, LA, January, 16, 2008.
[16] The UIC rulemaking that would create a Class VI well class for injection of CO_2 for the purposes of GS was proposed July 25, 2008. (73 FR 43492)

Table 4-2. Pro-forma Project Characteristics

	Per Project Averages for Economic Analysis					
Label	**Monitoring Wells/ Project**	**Monitoring Well Depth Ft**	**Footage all monitoring wells**	**Square Miles/ Project**	**Producing Oil or Gas Wells/ Project**	**Project Life (for annualization)**
Known DOE EOR Pilot Projects	7	5,700	39,900	8.8	56	10
Known DOE Saline Pilot Projects	2	8,000	16,000	1.7	0	4
Future DOE Saline Pilot Projects	2	8,000	16,000	1.7	0	4
Known Commercial EOR Projects	6	5,700	34,200	8.0	48	10
Known Commercial Saline Projects	9	8,000	72,000	11.6	0	40
Conversion of Existing EOR Projects to GS	6	5,700	34,200	8.0	48	10

The costs represent price levels in mid 2009, and are presented in 2008 dollars. There were very steep increases in the costs of equipment, materials and labor used in the construction of all types of energy infrastructure including power plants, pipelines and oil and gas wells from 2004 through 2008. With the drop of oil and natural gas prices in the Fall of 2008 and the general economic decline around the world the costs of equipment, materials and labor have moderated somewhat.

4.4.2.1 Primary Data Sources for Costs

Table 4-3 summarizes the major data sources for costs used by EPA in the analysis geologic sequestration costs. A wide range of cost data is available from industry survey publications for costs typically incurred in oil and gas drilling and production operations. This includes drilling and completion costs by region and depth interval, equipment and operating costs, and pipeline costs. Data are available for both the U.S. and Canada. [17] [18] [19] [20]The cost of drilling and equipping wells represents a large component of sequestration costs. The costs of additional equipment or material specifications for CO_2 injection wells are based in part upon various sources for corrosion resistant materials and specific well components. Cost estimates for seismic data acquisition are also available from industry publications and presentations.

Labor rates are obtained from the U.S. Bureau of Labor Statistics and from surveys of oil and gas professional performed by the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Engineers (SPE). The number of hours required to carry out the various characterization or monitoring activities are estimates that have been reviewed by the EPA workgroup.

Table 4-3. Major Sources of Geologic Sequestration Cost Information

Source	Cost Categories
API Joint Association Survey of Drilling Costs	Drilling costs in the U.S. for oil, gas, and dry holes by depth interval
EIA Oil and Gas Lease Equipment and Operating Cost Survey	Surface equipment costs, annual operating costs, pump costs
Pipeline Prime Mover and Compressor Costs (FERC)	Pumps
2008 Petroleum Services of Canada Well Cost Study (PSAC)	Drilling costs, plugging costs, logging costs
Oil and Gas Journal Report on Pipeline and Cost Data Reported to FERC	Pipeline costs per inch-mile
Land Rig Newsletter	Onshore rig day rates/ well cost algorithms
FutureGen Sequestration Site Submittals	Monitoring station layout/number of stations
Preston Pipe Report	Casing and tubing costs
Hourly Labor Rates	U.S. Bureau of Labor Statistics
Selected Presentations and Papers (see below)	Sensor costs, monitoring costs, number of stations, seismic costs

Significant Papers and Presentations With Cost Data

Benson, "Monitoring Protocols and Life Cycle Costs for Geologic Storage of Carbon Dioxide", Sept., 2004
IEA Greenhouse Gas Programme Report PH4/29, "Overview of Monitoring Requirements for Geologic Storage Projects, Nov., 2004.
Hoversten, "Investigation of Novel Geophysical Techniques for Monitoring CO2 Movement During Sequestration," Oct., 2003.
Dahowski, et al, " The Costs of Applying Carbon Dioxide Capture and Geologic Storage Technologies to Two Hypothetical Coal to Liquids Production Configurations: A Preliminary Estimation," Pacific NW National Laboratory, September, 2007.

[17] *Joint Association Survey of Drilling Costs*, American Petroleum Institute, Washington, DC. http://www.api.org/statistics/accessapi/api-reports.cfm

[18] *PSAC Well Cost Study – 2008*, Petroleum Services Association of Canada, October 30, 2007.

[19] *Oil and Gas Lease Equipment and Operating Costs*, U.S. Energy Information Administration, 2006, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

[20] *Oil and Gas Journal Pipeline Cost Survey*, Oil and Gas Journal Magazine, September 3, 2007.

The assumed capital costs and the annual operating cost of the various monitoring technologies whose application might be affected by the rule are shown in Table 4-4 and Table 4-5. The capital costs are annualized using a capital recovery factor of 0.295, 0.142, and 0.075 for projects lasting 4, 10, and 40 years, respectively. The annual O&M costs are added to the annualized capital costs to determine total annual direct costs. To this is added a 20 percent overhead and general and administrative cost factor to obtain total annual costs. These are then divided by the amount assumed to be received each year in the pro-forma project to arrive at total costs per metric ton of CO_2 received. These per-ton costs are then used to estimate total annual costs for the level of injection expected in the activity baseline.

4.4.3 Monitoring, Reporting, and Verification (MRV) Plan Requirements and Approval Process

There are two types of sites that will report under this rule, facilities that conduct GS (subpart RR) and all other facilities conducting CO_2 injection (subpart UU). All sites will incur costs associated with reporting the annual mass of CO_2 received, however only facilities conducting GS will incur the monitoring plan related costs. Under this rule facilities conducting GS must develop an MRV plan, submit it to EPA for approval, and implement it once approved by EPA to report the amount of CO_2 that has been sequestered. EPA is proposing that each submitted MRV plan must contain the following components.

1. Delineation of the maximum monitoring area and the period-specific monitoring areas.

2. Identification of potential surface leakage pathways for CO_2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.

3. A strategy for detecting and quantifying any surface leakage of CO_2.

4. A strategy for establishing the expected environmental baselines.

5. A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.

Table 4-4. Unit Cost of Relevant Continuous and Periodic Monitoring Technologies

Item	Capital Cost to Establish Environmental Baseline	Capital Cost for Construction and Equipment	Operating Cost
Deep Monitoring Wells (into or right above injection zone)	$200 lab fee per sample plus $1,000 to collect. 4 samples per well is $4,800 per well.	$20,700 + $5,200/well for design, $10,400 per well for surface disturbance, $165-$207 per foot to build, $20,800 for equipment	Annual O&M costs are $25,900 + $3.10/ft per well per year
CO_2 Flow Meters on Producing Oil and Gas Wells	NA	$10,400/ oil well	Annual O&M costs are $520 per well per year
CO_2 Flow & Gas Composition Meters on Producing Oil and Gas Wells	NA	$52,000/ oil well	Annual O&M costs are $2,600 per well per year
Periodic Sampling and Testing of Injected Fluid	NA	12 hours @$107.23/hr = $1,286 for plan	$200 lab fee per sample plus $270 to collect.
Estimation of Fugitive Emission from Surface Facilities	NA	40 hours @$107.23/hr = $4,289 for planning and initial inventory of facilities	24 hours @$107.23/hr = $2,574 for annual calculations
Periodic Seismic Surveys	Seismic survey baseline established as part of site characterization. No extra cost for monitoring.	No construction costs, but planning and quality assurance costs would add $25,000 per project.	$104,000 per square mile
Periodic Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation.	Initial survey before injection commences would establish baseline.	No construction costs, but planning and quality assurance costs would add $10,000 per square mile.	Airborne survey costs $250 per square mile would be $6,250. Plus mobilization costs of $5,000 per site.
Periodic mobile survey to detect surface leaks. May be good option where vegetation is sparse.	NA	No construction costs, but planning and quality assurance costs would add $10,000 per square mile.	Mobile survey costs $300 per hour. A square mile would take about 1 day and cost $2,400. Plus mobilization costs of $5,000 per site.
Eddy covariance measurement from permanent towers to detect surface leaks.	Establishing baseline is $35,000 per station.	40 hours @$107.23/hr = $4,289 for plan plus $70,000/monitoring site.	$10,000 per station per year
Soil zone monitoring (sampling gas from accumulation chambers)	Initial survey before injection commences would establish baseline.	40 hours @$107.23/hr = $4,289 for plan plus $6,000/monitoring site	$200 lab fee per sample plus $100 to collect.
Vadose zone monitoring wells to sample gas above water table.	Initial survey before injection commences would establish baseline.	40 hours @$107.23/hr = $4,289 for plan plus $8,000/monitoring site	$200 lab fee per sample plus $100 to collect.
Monitoring wells for samples from shallow water.	Initial survey before injection commences would establish baseline.	40 hours @$107.23/hr = $4,289 for plan plus $80,000/monitoring site	$200 lab fee per sample plus $1,000 to collect.

Table 4-5. Unit Cost of Relevant Episodic Monitoring Technologies (That may be employed after a subsurface leak is detected)

Detection Method	Method of Quantification	Estimate of Unit Cost for Leak Quantification	Cost per Episode	Probability of Application in Any Given Year per Project	Additional Annual Cost per Project for Leak Quantification
Surface leak detected by air, soil or water table monitoring or subsurface leak detected by pressure anomaly etc.	Material balance by solving for leaked quantity given known injected amounts and observed pressure in injection zone.	Leak volume estimation process 160 hours @$110.62/hr.	$17,698	1.0%	$177
Surface leak detected by MIT survey or by air, soil or water table monitoring.	Analysis of well logs (e.g., noise logs, oxygen activation logs) to quantify leaks along wellbore	Additional well log @4.15/ft +$2,070. Leak volume estimation process 160 hours @$110.62/hr.	$57,118	1.0%	$571
Subsurface leak detected by pressure anomaly in containment zone.	Analysis of pressure readings in several monitoring wells and reservoir simulation of leak.	Leak volume estimation process 320 hours @$110.62/hr.	$35,397	1.0%	$354
Surface leak detected by air, soil or water table monitoring.	Detailed seismic survey plus reservoir simulation to estimate leak volume at subsurface to help calibrate leak volume into atmosphere	$104,00 per square mile per survey. Leak volume estimation process 160 hours @$110.62/hr.	$121,698	1.0%	$1,217
Surface leak detected by air, soil or water table monitoring	Tenting of area to estimate leak volume. Alternative might be to use eddy covariance towers set up in leak area and compare flux from around towers set up in surrounding (nonleaking) areas.	Approximately $70,000 per square mile. Leak volume estimation process 80 hours @$110.62/hr.	$78,849	1.0%	$788
			Total per Year	**5.0%**	**$3,108**

Note: Assumes survey for leak occurs over one square mile area in each episode. Project's area is 10 square miles

4.5 Monitoring Technologies

Deep Monitoring Wells

Deep monitoring wells are typically drilled to monitor the deepest permeable zone above the caprock. Downhole instrumentation can be used to monitor pressure, temperature, and conductivity/salinity. Alternatively, U-tube devices can be used to retrieve pressurized samples for laboratory testing. Other types of monitoring from wells include micro-seismic, cross-well resistivity, and vertical seismic profiling.

CO_2 Flow Meters on Producing Oil and Gas Wells

Meters, probably located after the wellhead separator, that continuously measure the pressure, temperature and flow rate of the gas from a well. The composition of the gas is analyzed periodically using a gas chromatograph to determine percent CO_2 concentration. The mass of CO_2 passing through the wellhead can then be calculated from the measured quantities.

CO_2 Flow and Gas Composition Meters on Producing Oil and Gas Wells

Meters, probably located after the wellhead separator, that continuously measure the pressure, temperature, flow rate and chemical composition of the gas from a well. The mass of CO_2 passing through the wellhead can then be calculated from the measured quantities. This differs from the item directly above in that the chemical composition of the gas is being measured automatically by the meter itself rather through periodically obtaining a sample and sending it to lab for analysis.

Periodic Sampling and Testing of Injected Fluid

All facilities conducting GS and all other facilities conducting CO_2 injection will incur periodic sampling and testing costs. To estimate the costs, we have applied similar assumptions that were used in Subpart OO for sampling and testing of industrial gases. For example, we have assumed that it takes 12 labor hours to contact an onsite laboratory or offsite vendor and develop a plan; to collect and send the sample to an onsite or offsite laboratory; and to provide data invoice if sent offsite. Furthermore, we have assumed that it costs approximately $500 per sample to collect and conduct the test of chemical composition. In addition to these costs, facilities conducting GS will additionally incur the costs described in this rule.

Seismic Surveys

Seismic data acquisition involves the generation and detection of sound waves to evaluation conditions in the subsurface. Periodic acquisition of seismic data can be used to detect subsurface CO_2 movement within and outside of the reservoir.

Digital Color Infrared Ortho-imagery and Hyper-spectral Imaging

Digital color ortho-imagery and hyper-spectral imaging are airborne remote sensing technologies that are used to detect changes in vegetation resulting from CO_2 leaks. Hyperspectral sensors look at objects using electromagnetic spectrum. The object is to detect a specific spectral signature that is known to result from CO_2 uptake. The advantage of these methods is that they can efficiently cover a large surface area.

Airborne or Mobile Remote Sensing Survey

CO_2 detectors are commercially available for short closed-path and short open-path (point) measurements and long open-path (radial line) measurements. Similar detectors have been integrated into stationary, mobile, and airborne monitoring packages that are commonly used in combination with high-resolution global positioning system (GPS) to detect and quantify methane leaks in areas with road access. While these packages have not been widely tested for CO_2, various types of CO_2 monitors are commercially available and could be used in these applications. Such monitoring techniques are likely the leading candidates for monitoring plan applications because of their low cost and high reliability. The technologies include *infrared gas analyzers* (IRGAs, including Fourier transform infrared (FTIR) and non-dispersive infrared (NDIR) analyzers), tunable diode lasers (TDLs), cavity ring down techniques, and others. The sample path can range from 10 cm to 1 km, by reflecting a laser beam off retro-reflecting mirrors. These devices measure the gas concentration, and, when packaged with measurements of wind speed and wind direction, they measure the total gas flow.

LIDAR (Light Detection and Ranging) involves the transmission of light from an instrument to a target and the recording of the reflected light to determine some property of the target. Differential Absorption LIDAR (DIAL) uses two wavelengths of laser to measure CO_2. The wavelengths used are specific to CO_2. One wavelength is selected to correspond to a CO_2 spectral absorption line, while the other is a non-absorbing wavelength. The difference in intensity of the two return signals is a measure of concentration.

Eddy Covariance

Eddy Covariance is a technique whereby high frequency measurements of atmospheric CO_2 concentration at a height above the ground are made by an infra-red gas analyzer along with measurements of micro-meteorological variables such as wind velocity, direction, humidity, and temperature. Integration of these data allows derivation of the net CO_2 flux over the upwind footprint, typically square meters to square kilometers in area.

Soil Zone Monitoring with Accumulation Chamber (AC)

Surface CO_2 flux is measured using an accumulation chamber. The chamber is made of stainless steel with an open bottom and is placed at the sampling location. It may be placed either directly on the ground or on a collar installed in the ground surface. The air is circulated through the AC and measured with and infra-red gas analyzer.

Vadose Zone Monitoring

The vadose zone is the relatively shallow zone beneath the soil zone that is not saturated with groundwater. Small diameter probes are installed in the zone and samples are taken. The CO_2 concentration of air samples taken in this zone can be measured by and infrared gas analyzer.

Monitoring Wells for Sampling of Shallow Water

Shallow monitoring wells may be used to measure the properties of ground water. Such wells are typically no deeper than several hundred feet.

Estimating Leak Volumes after a Leak is Detected

The monitoring program for facilities conducting GS may detect subsurface leaks and it will be necessary to estimate the volume of leaks to the surface to comply with the reporting requirements of this rule. Each site operator will have to devise suitable techniques taking into account the geology of the sites, the location and nature of the potential leaks and the performance characteristics of available monitoring and measurement technologies.

It is expected that these estimates may include engineering estimates as well as some direct measurement and may have a wide margin of uncertainty. It is expected that site characterization and screening will lead to selection of sites that are suitable for long-term sequestration and that incidences of leaks to the surface may be infrequent at well-selected and well-managed sites. The cost estimates presented here for subsurface leak quantification assume a two percent chance in one year that any given site will have to implement the leak quantification strategy described in the site's MRV plan. There are no operating statistics for CO_2 GS from which to draw any citable conclusions on how often leaks to the surface may be detected, therefore a very conservative estimate was used in order to estimate the potential cost.

If the leak is detected in the subsurface (possibly by anomalous pressure readings in a monitoring well) the leak volume may be estimated to help calibrate a leak volume to the surface. Quantification is presumed to be done using engineering calculations supplemented, when technically feasible, by direct observation/measurement using, for example, a 3-D seismic survey over the area of the suspected leak. The seismic survey might be able to detect the location, size and density of the CO_2 plume formed by the leak in one or more containment zones located above the injection zone. The volume of the leak also might be estimated using a reservoir simulation model of the containment zone calibrated to the pressure readings of the monitoring wells surrounding the location of the leak. In other words, different volumes of leaks would be tested in the reservoir simulator to find which leak volume most closely matches the pressure history observed in the surrounding monitoring wells.

Leaks may also be detected at or near the surface by air, soil gas and water table monitoring devices. It is possible that some of the monitoring devices, such as eddy covariance, could themselves be used to estimate leak volumes. Another possible way of estimating the volume of a leak at the surface is to place a tent over the area of the leak. The tent would be sealed at the ground by weights or spikes and a calibrated volume of gas such as nitrogen would be introduced into the tent and allowed to escape through a chimney at the top of the tent. By measuring the concentration of CO_2 in the gases leaving the chimney it is possible to measure the amount of CO_2 leaving the ground in the area of the tent. The tent would have to be moved to many locations and the process repeated to get a representative sample over the entire area of the leak. It also would be necessary to correct the readings for natural CO_2 fluxes into and out of the soil.

Many of the leak detection methods for onshore GS sites can be applied to sub-seabed sites. These include monitoring of the injection well and monitoring of the subsurface CO_2 plume: active seismic, passive seismic, sensors in deep monitoring wells, and reservoir modeling. Though there will be differences in monitoring approaches at sub-seabed GS sites for leak detection and quantification, the cost estimates are assumed to be comparable.

Labor Rates

The cost of labor for many of the cost items and for General and Administrative Costs are based on Society of Petroleum Engineers (SPE) 2008 annual salary survey.[21] The average salary for a petroleum reservoir engineer with 15 years of experience is $143,800. Applying a 1.6 fringe and overhead factor yields an hourly burdened labor cost of $110.62 per hour.

The unit costs values reflect the cost of goods and services that would be purchased by the entity which owns the facility conducting GS. That entity would have additional General and Administrative Costs (G&A) on top of those direct costs for goods and services. These G&A cost are assumed to 20 percent of the direct costs.

4.5.1 Cost Scenarios

There are three cost scenarios (low, medium [or reference], and high) presented in Table 4-6 in terms of which monitoring devices would be used at a facility conducting GS and how often sampling and measurement would take place. Because each facility conducting GS will have unique characteristics that may result in the selection of different monitoring techniques, the application of the monitoring devices are indicated as percents of sites that would be expected to use each device or technique. Also shown in Table 4-6 are the portions of facilities that expected to be required to use the device or technique under the UIC Class VI permits and under UIC Class II permits. The cost impacts of the subpart RR are estimated as the monitoring and measurement requirements above and beyond the UIC Class II requirements. [22]

[21] For SPE survey of petroleum engineers see http://www.spe.org/spe-site/spe/spe/career/salary_survey/08SalarySurveyHighlights.pdf

[22] For the purposes of this rule, costs incremental to Class II requirements were estimated for ER projects conducting GS and costs incremental to the proposed Class VI requirements were estimated for all other GS projects.

Table 4-6. Assumptions for Application of Technologies by Cost Scenario

		Saline, Abandoned Oil & Gas Fields: Starting Point is UIC Class VI Requirements				ER plus GS: Starting Point is UIC Class II Requirements			
		Under UIC Class VI	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative	Under UIC Class II	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative
Deep Monitoring Wells (into or right above injection zone)	Fraction Projects	100%	100%	100%	100%	0%	100%	100%	100%
	Frequency (months)	Continuous	Continuous	Continuous	Continuous		Continuous	Continuous	Continuous
CO_2 Flow Meters on Producing Oil and Gas Wells	Fraction Projects	0%	0%	0%	0%	0%	100%	100%	100%
	Frequency (months)						Continuous	Continuous	Continuous
CO_2 Flow & Gas Composition Meters on Producing Oil and Gas Wells	Fraction Projects	0%	0%	0%	0%	0%	0%	0%	0%
	Frequency (months)						Continuous	Continuous	Continuous
Periodic Sampling and Testing of Injected Fluid	Fraction Projects	100%	100%	100%	100%	100%	100%	100%	100%
	Frequency (months)	3	3	3	3	3	3	3	3
Estimation of Fugitive Emission from Surface Facilities	Fraction Projects	0%	0%	100%	100%	0%	0%	0%	0%
	Frequency (months)	12	12	12	12	12	12	12	12
Periodic Seismic Surveys	Fraction Projects	25%	25%	25%	25%	0%	25%	25%	25%
	Frequency (months)	60	60	60	60	60	60	60	60
Periodic Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation.	Fraction Projects	0%	0%	50%	50%	0%	0%	50%	50%
	Frequency (months)	12	12	12	12	12	12	12	12

Table 4-6. Assumptions for Application of Technologies by Cost Scenario (continued)

		Saline, Abandoned Oil & Gas Fields: Starting Point is UIC Class VI Requirements				ER plus GS: Starting Point is UIC Class II Requirements			
		Under UIC Class VI	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative	Under UIC Class II	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative
Periodic mobile survey to detect surface leaks. May be good option where vegetation is sparse.	Fraction Projects	0%	0%	50%	50%	0%	0%	50%	50%
	Frequency (months)	12	12	12	12	12	12	12	12
Eddy covariance measurement from permanent towers to detect surface leaks.	Fraction Projects	25%	25%	25%	100%	0%	25%	25%	100%
	Frequency (months)	Continuous	Continuous	Continuous	Continuous	Continuous	Continuous	Continuous	Continuous
Soil zone monitoring (sampling gas from accumulation chambers)	Fraction Projects	0%	0%	100%	100%	0%	0%	100%	100%
	Frequency (months)	12	12	12	3	12	12	12	3
Vadose zone monitoring wells to sample gas above water table.	Fraction Projects	0%	0%	100%	100%	0%	0%	100%	100%
	Frequency (months)	12	12	12	3	12	12	12	3
Monitoring wells for samples from water table.	Fraction Projects	0%	0%	100%	100%	0%	0%	100%	100%
	Frequency (months)	12	12	12	3	12	12	12	3

4.6 Projecting and Discounting Project Costs

The cost per project (Table 4-7, below) is computed by applying the unit cost (Table 4-5) to the “pro-forma” characteristics assumed for each type of project meeting subpart RR requirements (Table 4-2).

Table 4-7. Summary of Cost Impacts Per Project: Subpart RR

		Environmental Baseline		Periodic Monitoring					
		Capital Costs	Annualized Capital Costs	Capital Cost	Annual Operating Cost	Annualized Capital and Contractor Costs	Annual Episodic Monitoring Costs	Overhead and G&A	Total Annual Costs
Under UIC Class VI or II	Known DOE EOR Pilot Projects	$ -	$0	$ 1,286	$ 1,880	$ 2,063	$0	$ 413	$ 2,476
	Known DOE Saline Pilot Projects	$ 7,438	$2,196	$ 3,103,485	$ 162,165	$1,078,401	$0	$ 216,119	$1,296,716
	Future DOE Saline Pilot Projects	$ 7,438	$2,196	$ 3,103,485	$ 162,165	$1,078,401	$0	$ 216,119	$1,296,716
	Known Commercial EOR Projects Class II	$ -	$0	$ 1,286	$ 1,880	$ 2,063	$0	$ 413	$ 2,476
	Known Commercial Saline Projects	$ 50,750	$3,807	$13,906,005	$ 624,642	$1,667,720	$0	$ 334,305	$2,005,832
	Conversion of Existing EOR Projects to GS Class II	$ -	$0	$ 1,286	$ 1,880	$ 2,063	$0	$ 413	$ 2,476
Low	Known DOE EOR Pilot Projects	$ 38,500	$5,482	$ 8,407,654	$ 475,253	$1,672,314	$3,108	$ 336,181	$2,017,083
	Known DOE Saline Pilot Projects	$ 7,438	$2,196	$ 3,103,485	$ 162,165	$1,078,401	$3,108	$ 216,741	$1,300,445
	Future DOE Saline Pilot Projects	$ 7,438	$2,196	$ 3,103,485	$ 162,165	$1,078,401	$3,108	$ 216,741	$1,300,445
	Known Commercial EOR Projects	$ 35,000	$4,983	$ 7,215,125	$ 419,491	$1,446,763	$3,108	$ 290,971	$1,745,824
	Known Commercial Saline Projects	$ 50,750	$3,807	$13,906,005	$ 624,642	$1,667,720	$3,605	$ 335,026	$2,010,158
	Conversion of Existing EOR Projects to GS	$ 35,000	$4,983	$ 7,215,125	$ 419,491	$1,446,763	$3,108	$ 290,971	$1,745,824

Table 4-7 (Continued). Summary of Cost Impacts Per Project: Subpart RR

		Environmental Baseline		Periodic Monitoring					
		Capital Costs	**Annualized Capital Costs**	**Capital Cost**	**Annual Operating Cost**	**Annualized Capital and Contractor Costs**	**Annual Episodic Monitoring Costs**	**Overhead and G&A**	**Total Annual Costs**
Reference	Known DOE EOR Pilot Projects	$ 84,340	$12,008	$ 9,436,084	$ 534,153	$1,877,639	$3,108	$ 378,551	$2,271,305
	Known DOE Saline Pilot Projects	$ 18,310	$5,406	$ 3,306,448	$ 180,151	$1,156,308	$3,108	$ 232,964	$1,397,785
	Future DOE Saline Pilot Projects	$ 18,310	$5,406	$ 3,306,448	$ 180,151	$1,156,308	$3,108	$ 232,964	$1,397,785
	Known Commercial EOR Projects	$ 76,900	$10,949	$ 8,150,061	$ 473,491	$1,633,877	$3,108	$ 329,587	$1,977,520
	Known Commercial Saline Projects	$ 110,380	$8,280	$15,265,951	$ 703,266	$1,848,352	$3,605	$ 372,047	$2,232,284
	Conversion of Existing EOR Projects to GS	$ 76,900	$10,949	$ 8,150,061	$ 473,491	$1,633,877	$3,108	$ 329,587	$1,977,520
High	Known DOE EOR Pilot Projects	$ 199,840	$28,453	$ 9,697,737	$ 614,673	$1,995,412	$3,108	$ 405,395	$2,432,367
	Known DOE Saline Pilot Projects	$ 40,623	$11,993	$ 3,356,995	$ 195,706	$1,186,786	$3,108	$ 240,377	$1,442,263
	Future DOE Saline Pilot Projects	$ 40,623	$11,993	$ 3,356,995	$ 195,706	$1,186,786	$3,108	$ 240,377	$1,442,263
	Known Commercial EOR Projects	$ 181,900	$25,898	$ 8,387,928	$ 546,691	$1,740,944	$3,108	$ 353,990	$2,123,940
	Known Commercial Saline Projects	$ 262,630	$19,700	$15,610,858	$ 809,406	$1,980,363	$3,605	$ 400,734	$2,404,401
	Conversion of Existing EOR Projects to GS	$ 181,900	$25,898	$ 8,387,928	$ 546,691	$1,740,944	$3,108	$ 353,990	$2,123,940

4.7 MRV Plan Development Costs

Facilities must develop a monitoring, reporting, and verification (MRV) plan, submit the MRV plan to EPA, receive an approved MRV plan from EPA, implement the EPA-approved plan, and submit annual report addenda in accordance with procedures in CFR 98.448(a). The MRV plan must include a delineation of the monitoring areas; an identification of potential surface leakage pathways and a risk assessment of leakage of the CO_2 through these pathways in the monitoring area; a strategy for detecting and quantifying any surface leakage of CO_2; a strategy for establishing the expected environmental baselines; and a summary of considerations made to calculate site-specific variables for the mass balance equation.

Facilities must submit the MRV plan on the schedule described in section 98.448(b). Facilities must re-submit the MRV plan for EPA approval according to section 98.448(g). An addendum describing the monitoring program that was implemented, including descriptions of monitoring anomalies and surface leakage, if any, must be submitted with the next annual report (March 31 of the subsequent calendar year).

The costs of the developing a MRV plan are reported in Tables 4-8 and 4-9.

Table 4-8. Cost of Developing MRV Plan under Subpart RR: New Project with existing UIC Class VI Permit

Scenario	Cost Item	Cost Algorithm in Hours	First Year Cost per Instance per Project	Frequency (every X years for 40-year injection + 50 year monitoring life)	Subsequent Year Cost per Instance per Project	Notes
New Project with UIC Class VI Permit	Evaluate Leakage Pathways	16	$ 1,770	once	$ 0	All raw data should be in UIC Class VI permit. Time is for re-interpretation relative to RR regs
New Project with UIC Class VI Permit	Delineate Areas of Monitoring	32	$ 3,540	5	$ 708	Modeling would be done for UIC Class VI, but needs to be interpreted for free phase plume. Maps need to be generated
New Project with UIC Class VI Permit	Develop strategy for leak detection, verification and quantification	160	$ 17,698	once	$ 0	Requires considerable statistical analysis not expected to be in UIC permit
New Project with UIC Class VI Permit	Establish baseline conditions	16	$ 1,770	once	$ 0	Requires more statistical analysis than expected to be in UIC permit. Data collection cost are already under each technology option.
New Project with UIC Class VI Permit	Tailor mass balance equation	8	$ 885	once	$ 0	
New Project with UIC Class VI Permit	Write MRV plan	400	$ 44,246	once	$ 0	Assume 100 pages at 4 hours per page
New Project with UIC Class VI Permit	Discuss MRV plan with EPA and edits	100	$ 11,062	once	$ 0	Assume most plans will be OK, but others will have to be redone to some degree. Assume 25% of first draft time.
New Project with UIC Class VI Permit	Annual Report	100	$ 11,062	1	$ 11,062	Assume 25 pages at 4 hours per page
New Project with UIC Class VI Permit	**All Items**	**832**	**$ 89,200**		**$ 11,770**	

Table 4-9. Cost of Developing MRV Plan under Subpart RR: ER Class II Project

Scenario	Cost Item	Cost Algorithm in Hours	First Year Cost per Instance per Project	Frequency (every X years for 10-year injection + 50 year monitoring life)	Subsequent Year Cost per Instance per Project	Notes
ER Class II Project (no Class VI Permit)	Evaluate Leakage Pathways	136	$ 15,044	once	$ 0	All raw data should exist through normal ER project evaluation and monitoring. However, considerable effort needed to interpret for RR regs.
ER Class II Project (no Class VI Permit)	Delineate Areas of Monitoring	756	$ 83,625	5	$ 16,725	Some modeling would be done for ER project evaluation and monitoring, but most likely need to be updated for MRV plan.
ER Class II Project (no Class VI Permit)	Develop strategy for leak detection, verification and quantification	160	$ 17,698	once	$ 0	Requires considerable statistical analysis not expected to be in UIC permit
ER Class II Project (no Class VI Permit)	Establish baseline conditions	16	$ 1,770	once	$ 0	Requires more statistical analysis than expected to be in UIC permit. Data collection cost are already under each technology option.
ER Class II Project (no Class VI Permit)	Tailor mass balance equation	16	$ 1,770	once	$ 0	More complex for ER
ER Class II Project (no Class VI Permit)	Write MRV plan	600	$ 66,369	once	$ 0	Assume 150 pages at 4 hours per page
ER Class II Project (no Class VI Permit)	Discuss MRV plan with EPA and edits	150	$ 16,592	once	$ 0	Assume most plans will be OK, but others will have to be redone to some degree. Assume 25% of first draft time.
ER Class II Project (no Class VI Permit)	Annual Report	100	$ 11,062	1	$ 11,062	Assume 25 pages at 4 hours per page
ER Class II Project (no Class VI Permit)	**All Items**	**1,934**	**$ 147,030**		**$ 27,787**	

4.8 Annual Report Costs

As part of the MRV plan, EPA is requiring annual reporting. Respondents are required to create an annual report each year. For costing purposes, EPA assumed a 25 page report that require 4 labor hours per page (annual cost is $11,062).

4.9 Other Recordkeeping and Reporting Costs

Additional recordkeeping ($1,700 per entity) and reporting ($500) costs per facility were also added to each project type.

4.10 Subpart UU Facility Costs

Facilities reporting under subpart UU will incur the following costs:

- Monitoring costs (no GS): $2,256 per year
- Other recordkeeping costs: $1,700 per year
- Other reporting costs: $500 per year

4.11 Summary of Reporting Costs by Facility Type and Subpart

Table 4-10 presents the costs by facility type and subpart.. The first column reports the facility type and associated subpart. The second and third columns report total costs for the first year and for subsequent years. The last 4 columns show the range of entity costs under different scenarios. These facility costs are used to compute the cost-to-sales ratios presented in section 5.

Table 4-10. Summary of Reporting Costs by Facility Type and Subpart (thousand, 2008$)

	Reference		Low		High	
Type (Subpart)	**First Year**	**Subsequent Years**	**First Year**	**Subsequent Years**	**First Year**	**Subsequent Years**
R&D (RR)[a]	$4	$4	$4	$4	$4	$4
GS Facilities (Saline) (RR)	$318	$240	$96	$18	$490	$413
GS Facilities (ER opt in) (RR)	$2,124	$2,005	$1,893	$1,773	$2,271	$2,151
CO_2 Injection Facilities (No GS) (UU)	$4	$4	$4	$4	$4	$4

[a]R&D facilities applying for a waiver will incur the reporting costs under UU ($4 thousand).

4.12 Public Sector Burden

EPA estimates the public sector burden to be $344,000 per year; $55,000 per year is for verification activities, and remaining costs are for program implementation and developing and maintaining the data collection system. Program implementation activities include, but are not limited to, evaluating monitoring plans, developing guidance and training materials to assist the regulated community, responding to inquires from affected facilities on monitoring and applicability requirements, and developing tools to assist in determining applicability.

SECTION 5
ECONOMIC IMPACT ANALYSIS

EPA prepares an EIA to provide decision makers with a measure of the social costs of using resources to comply with a program (EPA, 2000). As noted in EPA's (2000) *Guidelines for Preparing Economic Analyses*, several tools are available to estimate social costs and range from simple direct compliance cost methods to the development of a more complex market analysis that estimates market changes (e.g., price and consumption) and economic welfare changes (e.g., changes in consumer and producer surplus). Given data limitations and the size scope of the final rule, EPA has used the direct compliance cost method as a measure of social costs[23].

5.1 Threshold Analysis

EPA is requiring reporting from all facilities that meet the subpart UU (previously referred to as "Tier 1" facilities) source category definition and from all facilities that meet the subpart RR (previously referred to as "Tier 2" facilities) source category definition, at no threshold. EPA notes that a subpart RR threshold specific to ER projects that are not permitted as UIC Class VI is unnecessary because such projects can choose to opt-in to the subpart RR source category by implementing an EPA-approved MRV plan, regardless of quantity of CO_2 received.

An all-in reporting threshold will allow the Agency to comprehensively track all CO_2 supply (as reported in Suppliers of CO_2, subpart PP) that is received. This approach is consistent with the all-in requirements in the GHG Reporting Program for suppliers of petroleum, natural gas, and coal-to-liquid products (subparts LL, MM, and NN), producers of industrial gases (subpart OO), and suppliers of CO_2 (subpart PP). It was reasonable to require all of the facilities in these source categories to report because it would result in the most comprehensive accounting possible, simplify the rule, and permit facilities to quickly determine whether or not they must report; the same rationale applies for subparts RR and UU in today's rule. Furthermore, it will create a uniform burden for all covered facilities, ensuring a level playing field in, and preventing fragmentation of, the ER and GS sectors. Finally, EPA concluded that the same approach in both subparts UU and RR maximizes clarity and simplicity for facilities that choose to opt in from one to the other. The results of the threshold analysis are presented below in Table 5-1 and Table 5-2. For further information on the assumptions underlying the threshold analysis, please refer to the general technical support document (TSD) for proposal.[24]

---

[23] See pages 124 and 125 (EPA, 2000).
[24] Subpart RR General TSD (see docket ID No. EPA-HQ-OAR-2009-0926)

Table 5-1 Geologic Sequestration Facilities: Effect of CO_2 Received Threshold on Reported Amount of CO_2 Received and Number of Facilities Required to Report (Subpart RR)

Threshold Level (metric tons/yr of CO_2 received)	Total National (metric tons/yr of CO_2 received)	Total Number of U.S. Facilities	Amount of CO_2 Received		Number of Facilities	
			Metric tons/yr of CO_2 Received	Percent Covered	Number	Percent Covered
All In	7,162,885	10	7,162,885	100.00%	10	100.00%
1,000	7,162,885	10	7,162,885	100.00%	10	100.00%
10,000	7,162,885	10	7,162,885	100.00%	10	100.00%
25,000	7,162,885	10	7,162,885	100.00%	10	100.00%
100,000	7,162,885	10	7,162,885	100.00%	10	100.00%

Note: Includes the 9 R&D facilities assumed to apply for a R&D waiver.

Table 5-2. Facilities Conducting CO_2 Injection: Effect of CO_2 Received Threshold on Reported Amount of CO_2 Received and Number of Facilities Required to Report (Subpart UU)

Threshold Level (metric tons/yr of CO_2 received)	Total National (metric tons/yr of CO_2 received)	Total Number of U.S. Facilities	Amount of CO_2 Received		Number of Facilities	
			Metric tons/yr of CO_2 Received	Percent Covered	Number	Percent Covered
All In	48,735,442	92	48,735,442	100.00%	92	100.00%
1,000	48,735,442	92	45,431,115	93.22%	86	93.48%
10,000	48,735,442	92	45,419,065	93.20%	83	90.22%
25,000	48,735,442	92	45,325,238	93.00%	77	83.70%
100,000	48,735,442	92	44,385,039	91.07%	60	65.22%

Note: Includes the 9 R&D facilities assumed to apply for a R&D waiver and will subsequently be covered under subpart UU.

5.2 National Cost Estimates

The total annualized costs incurred under the rule by these entities would be approximately $1.1 million (in 2008$) in the first year and $1.0 million in subsequent years. This includes a public sector burden estimate of $344,000 for program implementation and verification activities. The typical annual cost for a facility conducting CO_2 injection (no GS) is about $4,000 per year (Table 5-3).

Table 5-3. National Annualized Mandatory Reporting Costs Estimates: Subpart RR and Subpart UU

			Reference	
			First Year	Subsequent Years
Type	Number	Metric Tons CO_2 Received per Year	thousand, 2008$	thousand, 2008$
R&D (RR)	9[a]	5,320,000	$36	$36
Facilities Conducting GS (Saline) (RR)	1	1,842,885	$318	$240
Facilities Conducting GS (ER) (RR)	0	0	$0	$0
Facilities Conducting CO_2 Injection (No GS) (UU)[b]	92[a]	48,735,442	$410	$410
5.3 Private Sector, Total All Projects	93[c]	50,578,327	$764	$686
Private Sector, Average ($/ton)			$0.02	$0.01
Public Sector, Total			$344	$344
National Total			$1,107	$1,030

[a]The 9 R&D facilities facilities are assumed to apply for a waiver and incur approximately $4,000 in costs under subpart RR. The 9 R&D will subsequently be covered under subpart UU (83 + 9 = 92) and incur the additional $4,000 in costs for subpart UU.

[b]Includes UIC Class II ER facilities.

cTotals are adjusted to avoid double counting of 9 R&D facilities. See footnote a.

.

Given uncertainties related to project adoption and the costs of the reporting program, EPA also considered two other private costs scenarios (one higher and one lower than the reference cost scenario) in order to assess a range of economic impacts on affected entities (Table 5-4).

Table 5-4. Annualized Mandatory Reporting Costs Estimates (2008$): Subpart RR and Subpart UU

	Low		High	
	First Year	Subsequent Years	First Year	Subsequent Years
Type	thousand, 2008$	thousand, 2008$	thousand, 2008$	thousand, 2008$
R&D (RR)	$36	$36	$36	$36
Facilities Conducting GS (Saline) (RR)	$96	$18	$490	$413
Additional Facilities Conducting GS (ER opt in) (RR)	$0	$0	$0	$0
Facilities Conducting CO_2 Injection (No GS) (UU)	$410	$410	$410	$410
Private Sector, Total All Projects	$542	$464	$936	$858
Private Sector, Average ($/ton)	$0.01	$0.01	$0.02	$0.02
Public Sector, Total	$344	$344	$344	$344
National Total	$885	$808	$1,279	$1,202

5.3.1 National Cost Estimates Under Alternative Facilities Conducting GS (ER opt in) Outcomes

Currently, the number of ER operations that would choose to report as facilities conducting GS (ER opt in) is unknown and EPA could not identify any information or analysis to estimate this quantity. As a result, two additional scenarios of the have been considered to represent medium and high outcomes. In the medium scenario, all Anthropogenic CO_2 projects (16) choose to report as facilities conducting GS (ER opt in)(Subpart RR). In the high scenario, all Anthropogenic CO_2 projects (16) and fifty percent of other CO_2 projects (32) choose to report as facilities conducting GS (ER opt in)(Subpart RR).

As shown in Tables 5-5, national cost estimate is $35 million under the medium ER opt in outcome (first year) and $33 million in subsequent years. As shown in Tables 5-6, national cost estimate is $103 million under the high ER opt in outcome (first year) and $97 million in subsequent years.

Table 5-5. National Annualized Mandatory Reporting Costs Estimates (2008): Assuming All Anthropogenic CO_2 Projects Opt-in

			All Anthropogenic CO_2 Projects	
			First Year	**Subsequent Years**
Type	**Number**	**Metric Tons CO_2 Received per Year**	**thousand, 2008$**	**thousand, 2008$**
R&D (RR)	9[a]	5,320,000	$36	$36
Facilities Conducting GS (Saline) (RR)	1	1,842,885	$318	$240
Additional Facilities Conducting GS (ER opt in) (RR)	16	6,972,040	$33,988	$32,080
Facilities Conducting CO_2 Injection (No GS) (UU)[b]	76[a]	41,763,402	$339	$339
Private Sector, Total All Projects	93[c]	50,578,327	$34,681	$32,695
Private Sector, Average ($/ton)			$0.69	$0.65
Public Sector, Total			$344	$344
National Total			$35,024	$33,039

[a]The 9 R&D facilities facilities are assumed to apply for a waiver and incur approximately $4,000 in costs under subpart RR. The 9 R&D will subsequently be covered under subpart UU (83 + 9 = 92) and incur the additional $4,000 in costs for subpart UU.

[b]Includes UIC Class II ER facilities.

cTotals are adjusted to avoid double counting of 9 R&D facilities. See footnote a.

Table 5-6. National Annualized Mandatory Reporting Costs Estimates (2008$): Assuming All Anthropogenic and 50 Percent of Other CO_2 Projects Opt-in

			All Anthropogenic and 50 Percent of Other CO_2 Projects	
			First Year	Subsequent Years
Type	Number	Metric Tons CO_2 Received per Year	thousand, 2008$	thousand, 2008$
R&D (RR)	9[a]	5,320,000	$36	$36
Facilities Conducting GS (Saline) (RR)	1	1,842,885	$318	$240
Additional Facilities Conducting GS (ER opt in) (RR)	48	23,543,741	$101,965	$96,241
Facilities Conducting CO_2 Injection (No GS) (UU)[b]	44[a]	25,191,701	$196	$196
Private Sector, Total All Projects	93[c]	50,578,327	$102,515	$96,714
Private Sector, Average ($/ton)			$2.03	$1.91
Public Sector, Total			$344	$344
National Total			$102,858	$97,057

[a]The 9 R&D facilities facilities are assumed to apply for a waiver and incur approximately $4,000 in costs under subpart RR. The 9 R&D will subsequently be covered under subpart UU (83 + 9 = 92) and incur the additional $4,000 in costs for subpart UU.

[b]Includes UIC Class II ER facilities.

cTotals are adjusted to avoid double counting of 9 R&D facilities. See footnote a.

5.3.2 National Cost Estimates Under Alternative Facilities Conducting GS (Commercial Saline) Outcomes

As discussed in Section 2, on February 3, 2010, President Obama established the CCS Task Force. The CCS Task Force, co-chaired by DOE and EPA, was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years, with a goal of bringing 5 to 10 commercial demonstration projects online by 2016. Additionally, the American Clean Energy Security Act (ACES) and the American Power Act

(APA) are estimated to induce about 30 percent of fossil-fuel-based electricity generation to come from power plants with CCS by 2040, rising to approximately 59 percent by 2050 (15 percent and 16 percent respectively of total electricity generation) (EPA, 2010). EPA analysis of APA projects deployment of over 30GW of CCS in 2030, which corresponds to over 54 550MW power plants. These modeling exercises show that CCS may play an important role in helping the United States meet carbon reduction targets.

Given the potential for future deployment of CCS technologies, EPA considered two additional scenarios of the number of large scale saline aquifer GS (commercial saline) project deployment by 2050: low (5 projects), medium (9 projects), and high (54 projects). The low scenario is based on the low end of the range of deployment targeted by the CCS Task Force. The medium scenario is based on large scale saline project deployment projected in the cost analysis prepared for the UIC Class VI final rule (73 FR 43492). The high scenario is based on EPA modeling of the projected deployment of CCS under the American Power Act. The national first year annual cost estimates increase by $1.6 million under the low outcome; $2.9 million under the medium outcome, and $17.2 million under the high outcome.

5.3.3 National Cost Estimates: 2011 to 2060 Using Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (UIC Class VI Rule) Baseline

EPA also conducted a cost analysis projected between 2011 and 2060. To do this, we used estimates of the anticipated level of U.S GS activity developed for the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (UIC Class VI Rule) economic analysis (EPA-HQ-OW-2008-0390). The UIC Class VI 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). Additional details about the development of the Geologic Sequestration Rule baseline can be found in section 3.4 of the UIC Class VI Rule's economic impact analysis (EPA-HQ-OW-2008-0390) Table 5-7 reports the baseline population numbers. As shown in Table 5-7, present value of the total costs incurred from 2011 to 2060 is estimate to be $346 million using a 3 percent discount rate) and $112 million using a 7 percent discount rate. The annualized values are $13.4 million using a 3 percent discount rate and 50 year period and $8.1 million using a 7 percent discount rate and 50 year period. These numbers are conservative estimates based on the assumption that the projects report for the entire time period. In some cases, the plume and pressure front may stabilize before 2060 resulting in fewer years of reporting costs. Waivered saline and waivered ER refers to the UIC Class VI Rule's provision that owners and operators may apply for and receive a waiver of the requirement to inject below the lowermost underground source of drinking water.

Table 5-7. Anticipated Level of U.S GS Activity Developed for the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (UIC Class VI Rule)

Year	Type of Formation					Total
	Saline Formations			Enhanced Recovery		
	Pilot Project	Large Project	Waivered Saline	ER	Waivered ER	
2011	0	0	0	0	0	0
2012	0	0.86	0.05	0	0	1
2013	0	0.86	0.05	0	0	1
2014	0	1.71	0.1	0	0	2
2015	0	0	0	0	0	0
2016	0	1.71	0.1	0	0	2
2017	2	4.28	0.24	0	0	7
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	0	0	0
2026	0	0	0	0	0	0
2027	0	0	0	0	0	0
2028	0	0	0	0	0	0
2029	0	0	0	0.86	0.05	1
2030	0	0	0	0	0	0
2031	0	0	0	0.86	0.05	1
2032	0	0	0	3.42	0.19	4
2033	0	0	0	2.57	0.14	3
2034	0	0	0	0.86	0.05	1
2035	0	0	0	1.71	0.1	2
2036	0	0	0	2.57	0.14	3
2037	0	0	0	0.86	0.05	1
2038	0	0	0	0	0	0
2039	0	0	0	0	0	0
2040	0	0	0	0	0	0
2041	0	0	0	0	0	0
2042	0	0	0	0	0	0
2043	0	0	0	0	0	0
2044	0	0	0	0	0	0
2045	0	0	0	0	0	0
2046	0	0	0	0	0	0
2047	0	0	0	0	0	0
2048	0	0	0	0	0	0
2049	0	0	0	0	0	0
2050	0	0	0	0	0	0
2051	0	0	0	0	0	0
2052	0	0	0	0	0	0
2053	0	0	0	0	0	0
2054	0	0	0	0	0	0
2055	0	0	0	0	0	0
2056	0	0	0	0	0	0
2057	0	0	0	0	0	0
2058	0	0	0	0	0	0
2059	0	0	0	0	0	0
2060	0	0	0	0	0	0
Total Sites	2.0	9.4	0.5	13.7	0.8	26

Source: Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (UIC Class VI Rule) economic analysis (EPA-HQ-OW-2008-0390)

5.4 Economic Impact Analysis

EPA assessed how the regulatory program may influence the profitability of companies by comparing the monitoring program costs to total sales (i.e., a "sales" test). Given limited data on commercial geological sequestration operations, EPA restricted the analysis to ER operations. ER activities account for approximately 90 percent of the project population (83 of 93 facilities). To do this, we divided the average annualized mandatory reporting costs per field by the estimated revenue for a representative field.

Sales Test Ratio= Average Cost (Table 5-3)/Estimated revenue (Table 5-6)

5.4.1 Revenue Estimate for a Representative Commercial ER Operation

EPA obtained national production statistics from the latest Department of Energy report about CO_2 ER technologies (DOE, 2009). Data suggest a typical operation produces approximately 776,000 barrels of oil per year. Using the DOE choice of an average long-term price of oil ($70), EPA estimated total revenue of $54.3 million per year. To enhance the transparency of the calculation, we provide data, sources, and methods in Table 5-8.

Table 5-8. Estimated Annual Revenue for a Representative Commercial ER Field Operation (2008)

Label	Variable	Value	Source and Calculation Method
A	Barrels Per Day	250,000	DOE, 2009 p: 19
B	Barrels per year	77,562,500	A × 0.85 × 365
C	Population	100	DOE, 2009 p: 19
D	Average Barrels per year	775,625	B / C
E	Price per barrel	$70	DOE, 2009 p: 2
F	Total Revenue ($ million)	$54	D× E

Source: EPA calculations using data from DOE (2009). Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-ER Technology, accessed October 28, 2009.

5.4.2 Sales Test Results

As shown in Table 5-9 sales test ratios are between 3.3 to 4.2 percent for facilities conducting GS (Subpart RR). In contrast, facilities conducting CO_2 injection (no GS, which includes Class II ER operations) sales test ratios are below 0.1 percent.

Table 5-9. Sales Tests for Representative Commercial ER Field Operations

			Alternative Cost Scenarios			
	Reference		Low		High	
Type	First Year	Sub-sequent Years	First Year	Sub-sequent Years	First Year	Sub-sequent Years
Facilities Conducting GS (ER opt in) (RR)	3.9%	3.7%	3.5%	3.3%	4.2%	4.0%
Facilities Conducting CO_2 Injection (No GS) (UU)	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%

5.5 Assessing Economic Impacts on Small Entities

The first step in this assessment was to determine whether the rule will have a significant impact on a substantial number of small entities (SISNOSE). To make this determination, EPA used a screening analysis that allows us to indicate whether EPA can certify the rule as not having a SISNOSE. The elements of this analysis included

- identifying affected sectors and entities,
- selecting and describing the measures and economic impact thresholds used in the analysis, and
- determining SISNOSE certification category.

5.5.1 Identify Affected Sectors and Entities

For the purposes of assessing the impacts of the rule on small entities, we defined a small entity as (1) a small business, as defined by SBA's regulations at 13 CFR Part 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; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

For the Carbon Dioxide Injection and Geologic Sequestration Reporting Rule, small entity is defined as a small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; according to these size standards, ultimate parent companies owning oil and gas extraction operations (NAICS 211) are categorized as small if the total number of employees at the firm is fewer than 500.

The Oil & Gas Journal publishes a list of companies owning active U.S. CO_2 ER projects in 2008 (OGJ, 2008). EPA's initial review of publicly available sales and employment databases suggest up to 9 of the 23 companies listed in the OGJ survey have fewer than 500 employees.

5.5.2 Develop Small Entity Economic Impact Measures

The sales test examined the average total annualized mandatory reporting costs per ER field to a representative measure of revenue. Details are provided in section 5.3.

5.5.3 Results of Screening Analysis

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure 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.

After considering the economic impact of the rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. Currently EPA believes small ER operations will most likely be facilities conducting CO_2 injection (no GS), including Class II ER projects. The average ratio of annualized reporting program costs to revenues of a typical ER operation likely owned by representative small enterprises is less than 1%.

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this rule on small entities. For example, monitoring and reporting requirements are built off of the UIC program. In addition, EPA is requiring equipment and methods that may already be in use by a facility for compliance with its UIC permit. Also, EPA is requiring annual reporting instead of more frequent reporting.

During rule implementation, EPA will maintain an "open door" policy for stakeholders to ask questions about the rule or provide suggestions to EPA about the types of compliance assistance that will be useful to small businesses. EPA intends to develop a range of compliance assistance tools and materials and conduct extensive outreach for this final rule.

5.6 Characterization of Benefits of Subpart RR and Subpart UU of the Mandatory Reporting Rule

Sequestering CO_2 in geologic formations has climate benefits and has been recognized as an important climate mitigation technology. The benefits and costs of this rule were considered against the backdrop of current regulations, none of which require or provide incentives for geologic sequestration. As this final rule does not require owners or operators to undertake geologic sequestration, the benefits directly associated with this rule are more appropriately related to the reporting of GHG emissions and amounts sequestered. Because quantifying the benefits of a policy that monitors but does not reduce GHG emissions would be very difficult, the benefits laid out in this chapter are strictly qualitative. EPA evaluated the benefits of a reporting system with respect to policy making relevance, transparency issues, and market efficiency. The following discussion describes one possible means of quantifying benefits and provides an overview of the qualitative benefits evaluated.

5.6.1 Social Cost of Carbon

The social cost of carbon (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 was composed of technical experts from a number of Federal agencies. In developing these estimates, the working group considered public comments, explored the technical literature in relevant fields, discussed key model inputs and assumptions, and developed estimates of the global benefits of avoiding climate change.

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.

There are a few important caveats to consider when evaluating benefits using SCC, which are discussed in detail in the Social Cost of Carbon TSD as part of the EPA Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards Final Rule.[25]

1. The integrated assessment models used do not completely capture catastrophic and non-catastrophic impacts.
2. The integrated assessment models are incomplete in their treatment of adaptation and technological change.
3. There is uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion.

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 associated with geologic sequestration may be better ascribed to regulations that require and/or provide incentives for geologic sequestration. Based on this analysis and the preceding discussion of caveats, EPA did not employ SCC estimates to calculate the benefits of this rule. Instead, as discussed below, EPA evaluated the benefits of this rule qualitatively.

5.6.2 Qualitative Benefits Review

A mandatory reporting system will benefit the public by increased transparency of facility GHG data. Transparent, public data on GHGs allows for accountability of polluters to the public stakeholders who bear the cost of the pollution. Citizens, community groups, and labor unions have made use of data from Pollutant Release and Transfer Registers to negotiate directly with polluters to lower emissions, circumventing greater government regulation. Publicly available emissions data also will allow individuals to alter their consumption habits based on the GHG emissions of producers. In the case of geologic sequestration, the data requirements and transparency of the rule may also serve to broaden public understanding and acceptance of the technology as a viable mitigation option.

[25] Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule (May 7, 2010) http://epa.gov/otaq/climate/regulations.htm#1-1

The greatest benefit of mandatory reporting of GHGs to government will be realized in developing future GHG policies. Benefits to industry of GHG monitoring include the value of having independent, verifiable data to present to the public to demonstrate appropriate environmental stewardship, and a better understanding of their emission levels and sources to identify opportunities to reduce emissions. Such monitoring allows for inclusion of standardized GHG data into environmental management systems, providing the necessary information to achieve and disseminate their environmental achievements.

Standardization will also be a benefit to industry, once facilities invest in the institutional knowledge and systems to report GHG data, the cost of monitoring should fall and the accuracy of the accounting should improve. A standardized reporting program will also allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry.

SECTION 6
STATUTORY AND EXECUTIVE ORDER REVIEWS

This section describes EPA's compliance with several applicable executive orders and statutes during the development of the final Injection and Geologic Sequestration of Carbon Dioxide Reporting Rule.

6.1 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 may raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the EO. 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.

EPA prepared an analysis of the potential costs and benefits associated with this action in the EIA (EPA-HQ-OAR-2009-0926). A copy of the analysis is available in the docket for this action and the analysis is briefly summarized here. In the EIA, EPA has identified the regulatory options considered, their costs, the emissions that would likely be reported under each option, and explained the selection of the option chosen for the rule. The costs of the rule are reported in Section 4 of the EIA, and the economic impacts and qualitative benefits assessment are reported in Section 5 of the EIA. Overall, EPA has concluded that the costs of the Injection and Geologic Sequestration of Carbon Dioxide Reporting Rule are justified by the potential benefits of more comprehensive information about CO_2 injection. In the absence of new climate policy, the total annualized cost of the rule will be approximately $1.1 million (in 2008$) during the first year of the program and $1.0 million in subsequent years (including 344,000 of programmatic costs to the Agency).

6.2 Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2372.02.

EPA has identified the following goals of the GHG reporting system:

- Obtain data that is of sufficient quality that it can be used to analyze and inform the development of a range of future climate change policies and potential regulations.

- Create reporting requirements that are, to the extent possible and appropriate, consistent with existing GHG reporting programs in order to reduce reporting burden for all parties involved.

The information from CO_2 injection and geologic sequestration facilities will allow EPA to make well-informed decisions about whether and how to use the CAA to regulate these facilities and encourage voluntary reductions. Because EPA does not yet know the specific policies that will be adopted, the data reported through the mandatory reporting system should be of sufficient quality to inform policy and program development. Also, consistent with the Appropriations Act, the reporting rule covers a broad range of sectors of the economy including sites that inject and store CO_2.

This information collection is mandatory and will be carried out under CAA section 114. Information identified and marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. However, emissions information collected under CAA section 114 generally cannot be claimed as CBI and will be made public.[26]

The projected cost and hour burden for non-Federal respondents is $7.0 million and 9,416 hours per year. The estimated average burden per response is 56.6 hours; the frequency of response is annual for all respondents that must comply with the rule's reporting requirements; and the estimated average number of likely respondents per year is 93. The cost burden to respondents resulting from the collection of information includes the total capital and start-up cost annualized over the equipment's expected useful life (averaging $717,000 per year) a total operation and maintenance component (averaging $5.3 million per year), and a labor cost component (averaging $1.0 million per year).

Burden is defined at 5 CFR part 1320.3(b). Although not included in the primary economic analysis, the costs and burdens to the ER opt ins were estimated using an alternate cost scenario and in this section EPA is giving its best estimates of likely costs and burdens, including to voluntary reporters, as required by the Paperwork Reduction Act. These cost numbers differ

[26] Although CBI determinations are usually made on a case-by-case basis, on July 7, 2010, EPA published a proposed rule (75 FR 39094) relating to CBI determinations for the data collected under the GHG Reporting Program (40 CFR part 98).

from those shown elsewhere in the EIA for this final rule because ICR costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the EIA for the first year of the rule and for subsequent years of the rule. Also, the ICR focuses on respondent burden only, while the EIA for this final rule includes EPA Agency costs as well. 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. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the Federal Register to display the OMB control number for the approved information collection requirements contained in this final rule.

6.3 Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure 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.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's 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.

This rule will not have a significant economic impact on a substantial number of small entities. Currently EPA has determined that small ER operations will most likely be facilities conducting CO_2 injection only, including UIC Class II ER projects, which are only required to report under subpart UU. The average ratio of annualized reporting program costs to revenues of a typical ER operation likely owned by representative small enterprises is less than 1 percent.

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this rule on small entities. For example, monitoring and reporting requirements are built off of the UIC program. In addition, EPA is requiring equipment and methods that may already be in use by a facility for compliance with its UIC permit. Also, EPA is requiring annual reporting instead of more frequent reporting.

During rule implementation, EPA will maintain an "open door" policy for stakeholders to ask questions about the rule or provide suggestions to EPA about the types of compliance assistance that will be useful to small businesses. EPA intends to develop a range of compliance assistance tools and materials and conduct extensive outreach for this final rule.

6.4 Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), P.L. 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under CAA section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for final rules with "Federal mandates" that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year.

This final 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. Overall, EPA estimates that the total annualized costs of this final rule are approximately $1.1 million (in 2008$) during the first year of the program and $1.0 million in subsequent years (including $344,000 of programmatic costs to the Agency). Thus, this final rule is not subject to the requirements of CAA sections 202 or 205 of the UMRA.

This final rule is also not subject to the requirements of CAA section 203 of the UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Facilities subject to this final rule include facilities that inject CO_2 for enhanced recovery, and those that sequester CO_2. None of the facilities currently known to undertake these activities are owned by small governments.

6.5 Executive Order 13132: Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications." "Policies that have Federalism implications" is defined in the EO to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

This final rule does not have Federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132.

This regulation applies to public- or private-sector facilities that inject CO_2 underground. Few government facilities would be affected. This regulation applies directly to facilities that inject CO_2 underground. It does not apply to governmental entities unless the government entity owns a facility that injects and/or sequesters CO_2 underground. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, EO 13132 does not apply to this final rule. However, as it is EPA's policy to promote communication between the Agency and State and local governments, EPA specifically solicited comments on the proposed rule from State and local officials.

6.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled “Consultation and Coordination with Indian Tribal Governments” (59 FR 22951, November 6, 2000), requires EPA to develop an accountable process to ensure “meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.”

This action does not have Tribal implications, as specified in EO 13175 (65 FR 67249, November 9, 2000). This regulation applies directly to facilities that inject and/or sequester CO_2 underground. EPA analyzed the facilities expected to be affected by this rule and did not find that any facilities expected to be affected by the rule are likely to be owned by tribal governments. In addition, EPA did not hear from any Tribal governments contradicting this analysis. Thus, EO 13175 does not apply to this final rule.

Although EO 13175 does not apply to this final rule, EPA sought opportunities to provide information to Tribal governments and representatives during development of the GHG reporting rule. In consultation with EPA’s American Indian Environment Office, EPA’s outreach plan included tribes. EPA conducted several conference calls with Tribal organizations during the proposal phase of the GHG reporting rule. For example, EPA staff provided information to tribes through conference calls with multiple Tribal working groups and organizations at EPA that interact with tribes and through individual calls with two Tribal board members of TCR. In addition, EPA prepared a short article on the GHG reporting rule that appeared on the front page of a Tribal newsletter—Tribal Air News—that was distributed to EPA/Office of Air Quality Planning & Standards’ network of Tribal organizations. EPA gave a presentation on various climate efforts, including the GHG Reporting Program, at the National Tribal Conference on

Environmental Management on June 24-26, 2008. In addition, EPA had copies of a short information sheet distributed at a meeting of the National Tribal Caucus. See the "Summary of EPA Outreach Activities for Developing the GHG reporting rule," in Docket No. EPA–HQ–OAR–2008–0508–055 for a complete list of Tribal contacts. EPA participated in a conference call with Tribal air coordinators in April 2009 and prepared a guidance sheet for Tribal governments on the proposed GHG reporting rule. It was posted on the GHG Reporting Program website and published in the Tribal Air Newsletter.

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

This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks, and it is not an economically significant regulatory action under EO 12866.

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

This final 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. Further, EPA has concluded that this rule is not likely to have any adverse energy effects. This final rule relates to monitoring, reporting and recordkeeping at facilities that inject and/or sequester CO_2 underground and does not impact energy supply, distribution or use. Oil and gas operations that use CO_2-ER are only required to report under subpart UU, unless they opt into subpart RR to establish that CO_2 is being geologically sequestered. Therefore, we conclude that this rule is not likely to have any adverse effects on energy supply, distribution, or use.

6.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104-113 (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, with explanations when the Agency decides not to use available and applicable voluntary consensus standards. This rulemaking involves technical standards. EPA developed no new measuring device standard. Rather we allow the use of an appropriate standard method published by a consensus-based standards organization if such a method exists; or an industry standard practice.

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

Executive Order 12898 (59 FR 7629, February 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 the final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. The final rule does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures only.

6.11 Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the <u>Federal Register</u>. A major rule cannot take effect until 60 days after it is published in the <u>Federal Register</u>. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective [INSERT THE DATE 30 DAYS AFTER PUBLICATION OF THIS FINAL RULE IN THE FEDERAL REGISTER OR DECEMBER 31, 2010, WHICHEVER IS EARLIER].

SECTION 7
CONCLUSIONS

EPA is promulgating a regulation to require monitoring and reporting from facilities that conduct carbon dioxide (CO_2) injection and geologic sequestration (GS). This rule does not require control of greenhouse gases (GHGs), rather it requires only monitoring and reporting of GHGs.

7.1 Summary of Selected Regulatory Alternative

This final rule amends 40 CFR part 98 to add reporting requirements covering facilities that conduct geologic sequestration of CO_2 (40 CFR part 98, subpart RR) and all other facilities that conduct injection of CO_2 (40 CFR part 98, subpart UU).[1] GS is the long-term containment of a CO_2 stream in subsurface geologic formations. This data will, among other things, inform Agency decisions under the CAA related to the use of carbon dioxide capture and geologic sequestration (CCS) for mitigating GHG emissions.

Subpart RR information will enable EPA to monitor the growth and efficacy of GS (and therefore CCS) as a GHG mitigation technology over time and to evaluate relevant policy options. Furthermore, where enhanced oil and gas recovery (ER) projects are reporting under 40 CFR part 98, subpart RR, EPA will be able to evaluate ER as a non-emissive end use. Under 40 CFR part 98, subpart UU, EPA will be able to reconcile information obtained from this rule with data obtained from 40 CFR part 98, subpart PP on CO_2 supplied to the economy.

The rule was proposed by EPA on April 12, 2010. One public hearing was held on April 19, 2010, and the sixty day public comment period ended June 11, 2010. This rule takes into consideration comments received during the comment period and finalizes the monitoring and reporting requirements for facilities conducting GS and all other facilities conducting CO_2 injection.

This final rule does not address whether data reported under 40 CFR part 98, subparts RR or UU will be released to the public or will be treated as CBI. EPA published a proposed rule on confidentiality determination on July 7, 2010 (75 FR 39094) that addressed this issue. In that action, EPA proposed which specific data elements may be released to the public and which

[1] EPA has moved all definitions, requirements, and procedures for facilities conducting CO_2 injection only (which both EPA and commenters have referred to as "Tier 1 " facilities for simplicity) into a new subpart, 40 CFR part 98, subpart UU, and retained all definitions, requirements, and procedures related to facilities conducting GS (which both EPA and commenters have referred to as "Tier 2" facilities for simplicity) in 40 CFR part 98, subpart RR.

would be treated as CBI. EPA received several comments on that proposal under that action, and is in the process of considering these comments. A final rule and determination will be issued before any data are released.

7.2 Estimated Costs and Impacts of the Mandatory GHG Reporting Program

Under the rule, EPA estimates that 93 facilities would be covered by the rule. The total annualized costs incurred under the rule by these entities would be approximately $1.1 million (in 2008$) in the first year and $1.0 million in subsequent years. This includes a public sector burden estimate of $344,000 for program implementation and verification activities. These costs represent less than 0.0001% of 2008 gross domestic product; overall, EPA does not believe the rule will have a significant macroeconomic impact on the national economy or on small entities within those sectors.

7.2.1 Alternative Scenarios Considered

7.2.1.1 Facilities Conducting GS (ER opt in) Outcomes

Currently, the number of ER operations that would choose to report as facilities conducting GS (ER opt in) is unknown and EPA could not identify any information or analysis to estimate this quantity. As a result, two additional scenarios of the have been considered to represent medium and high outcomes. In the medium scenario, all Anthropogenic CO_2 projects (16) choose to report as facilities conducting GS (ER opt in) (Subpart RR). In the high scenario, all Anthropogenic CO_2 projects (16) and fifty percent of other CO_2 projects (32) choose to report as facilities conducting GS (ER opt in) (Subpart RR). As shown in Tables 5-5, national cost estimate is $35 million under the medium ER opt in outcome (first year) and $33 million in subsequent years. As shown in Tables 5-6, national cost estimate is $103 million under the high ER opt in outcome (first year) and $97 million in subsequent years.

7.2.1.2 Facilities Conducting GS (Commercial Saline) Outcomes

Given the potential for future deployment of CCS technologies, EPA considered two additional scenarios of the number of large scale saline aquifer GS (commercial saline) project deployment by 2050: low (5 projects), medium (9 projects), and high (54 projects). The low scenario is based on the low end of the range of deployment targeted by the CCS Task Force. The medium scenario is based on large scale saline project deployment projected in the cost analysis prepared for the UIC Class VI final rule (73 FR 43492). The high scenario is based on EPA modeling of the projected deployment of CCS under the American Power Act. The national first year annual cost estimates increase by $1.6 million under the low outcome; $2.9 million under the medium outcome, and $17.2 million under the high outcome.

SECTION 8
REFERENCES

Benson, S.M., 2006, "Monitoring Carbon Dioxide Sequestration in Deep Geological Formations for Inventory Verification and Carbon Credits," Society of Petroleum Engineers Paper 102833, 14pp.

Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations, by Kevin Bliss, Interstate Oil and Gas Compact Commission, January, 2005.

Carbon Sequestration Atlas of the United States and Canada, 2008, U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV.

Direct Carbon Sequestration: Capturing and Storing Carbon Dioxide, Congressional Research Service, report RL33801, September, 2007.

Discussion Paper: Identifying Gaps in CO_2 Monitoring and Verification of Storage, by B. Reynen, M. Wilson, N. Riley, T. Manai, O. M. Mathiassen, and S. Holloway, A Task Force under the Technical Group of the Carbon Sequestration Leadership Forum, (CSLF), Paper No. CSLF-T-2005-3, Presented at the Technical Group Meeting, April 30, 2005

The Economics of CO_2 Storage, Gemma Heddle, Howard Herzog, and Michael Klett, Laboratory for Energy and the Environment, Massachusetts Institute of Technology, August, 2003.

The Future of Coal, Options for a Carbon-constrained World, An Interdisciplinary MIT Study, Massachusetts Institute of Technology, 2007.

FutureGen Alliance, 2006, "Mattoon Site Environmental Information Volume," December, 2006.

Ground Water Protection Council Meeting, New Orleans, LA, January, 16, 2008.

IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

Joint Association Survey of Drilling Costs, American Petroleum Institute, Washington, DC. http://www.api.org/statistics/accessapi/api-reports.cfm

Oil and Gas Journal, April 17, 2006.

Oil and Gas Journal Pipeline Cost Survey, Oil and Gas Journal Magazine, September 3, 2007.

PSAC Well Cost Study – 2008, Petroleum Services Association of Canada, October 30, 2007.

Regional Carbon Sequestration Partnerships Annual Project Review Meeting, DOE/NETL, December 12, 2007.

U.S. Department of Energy, National Energy Technology Laboratory website, www.netl.doe.gov

Oil and Gas Lease Equipment and Operating Costs, U.S. Energy Information Administration, 2006, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

U.S. Department of Energy (DOE). 2009. Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-ER Technology, accessed October 28, 2009.

U.S. Environmental Protection Agency (EPA). September 2000. *Guidelines for Preparing Economic Analyses*. EPA 240-R-00-003. Washington, DC: EPA. Available at: http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/Guidelines.html.

U.S. Environmental Protection Agency. 2010. EPA Analysis of the American Power Act of 2010 in the 111th Congress. http://epa.gov/climatechange/economics/economicanalyses.html#apa2010