Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Under Subpart W Final Rule (GHG Reporting)

Final Report

November 2010

TABLE OF CONTENTS

Page

LIST OF FIGURES

Page

LIST OF TABLES

ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
ARP	accidental release prevention
BLS	Bureau of Labor Statistics
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
CAA	Clean Air Act
CARB	California Air Resources Board
CBI	confidential business information
CEMS	continuous emission monitoring system
CCAR	California Climate Action Registry
CFR	Code of Federal Regulations
CH_4	methane
CMOP	Coalbed Methane Outreach Program
CO_2	carbon dioxide
CO_2e	carbon dioxide-equivalent
CRF	capital recovery factor
ERMR	Essential Requirements for Mandatory Reporting
DOD	Department of Defense
DOE	Department of Energy
DOT	Department of Transportation
EGU	electric generating unit
EIA	Economic Impact Analysis
EO	executive order
EPA	U.S. Environmental Protection Agency
ERMR	Essential Requirements for Mandatory Reporting
FAQ	frequently asked questions
FERC	Federal Energy Regulatory Commission
FR	Federal Register
GHG	greenhouse gas
GOADS	Gulfwide Offshore Activity Data System
GoM	Gulf of Mexico
GRI	Gas Research Institute
HHV	high heating value
ICR	information collection request
IPCC	Intergovernmental Panel on Climate Change
LDC	local distribution company

LMOP	Landfill Methane Outreach Program
LNG	liquefied natural gas
M&R	metering and regulating
MMBtu	million British thermal units
MMS	Minerals Management Service
$MtCO_2e$	metric tons of carbon dioxide-equivalent
MW	megawatt
NAICS	North American Industry Classification System
NEI	National Emissions Inventory
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NTTAA	National Technology Transfer and Advancement Act of 1995
O&M	operations and maintenance
OECD	Organisation for Economic Co-operation and Development
OMB	Office of Management and Budget
PFC	perfluorocarbon
PRTR	pollutant release and transfer registers
PSD	Prevention of Significant Deterioration
QAPP	Quality Assurance Project Plan
QA/QC	quality assurance/quality control
OAQPS	Office of Air Quality Planning and Standards
R&D	research and development
RFA	Regulatory Flexibility Act
RGGI	Regional Greenhouse Gas Initiative
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SF_6	sulfur hexafluoride
SISNOSE	significant impact on a substantial number of small entities
SUSB	Statistics of U.S. Businesses
TCR	The Climate Registry
TRI	Toxics Release Inventory
TSD	Technical Support Document
UMRA	Unfunded Mandates Reform Act
UNFCCC	United Nations Framework Convention on Climate Change
U.S.C.	United States Code
USDA	U.S. Department of Agriculture
WBCSD	World Business Council for Sustainable Development

WCI	Western Climate Initiative
WRI	World Resources Institute

Disclaimer

The Environmental Protection Agency (EPA) regulations cited in this Economic Impact Analysis (EIA) contain legally-binding requirements. Several sections of the EIA offer illustrative examples for complying with the minimum requirements indicated by the regulations. This is done to provide information that may be helpful to understand the costs associated with reporters' implementation efforts. Such recommendations are prefaced by the words "may" or "should" and are to be considered advisory. They are not required elements of the regulations cited in this EIA. Therefore, this document does not substitute for the regulations cited in this EIA, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA or the regulated community. It may not apply to a particular situation based upon the circumstances. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

While EPA has made every effort to ensure the accuracy of the discussion in this document, the obligations of the regulated community are determined by statutes, regulations or other legally binding requirements. In the event of a conflict between the discussion in this document and any statute or regulation, this document would not be controlling.

SECTION 1
INTRODUCTION AND BACKGROUND

1.1 Background

On December 26, 2007, President Bush signed the fiscal year (FY) 2008 Consolidated Appropriations Amendment, which authorized funding for the U.S. Environmental Protection Agency (EPA) to develop and publish a draft rule on an accelerated schedule:

> [N]ot less than $3,500,000 shall be provided for activities to develop and publish a draft rule not later than 9 months after the date of enactment of this Act, and a final rule not later than 18 months after the date of enactment of this Act, to require mandatory reporting of [greenhouse gas] GHG emissions above appropriate threshold in all segments of the economy.

The accompanying explanatory text stated that EPA shall "use its existing authority under the Clean Air Act" to develop a mandatory GHG reporting rule.

> The agency is further directed to include in its rule reporting of emissions resulting from upstream production and downstream sources, to the extent that the Administrator deems it appropriate. The Administrator shall determine appropriate thresholds of emissions above which reporting is required, and how frequently reports shall be submitted to EPA. The Administrator shall have discretion to use existing reporting requirements for electric generating units under Section 821 of the Clean Air Act.

EPA signed the final mandatory GHG reporting rule (40 Code of Federal Regulations [CFR] Part 98) on September 22, 2009, which was published in the October 30, 2009 Federal Register (FR) (74 FR 56260). This rule did not include Subpart W, Petroleum and Natural Gas Systems, due to the extensive number of comments received on the April 10, 2009, proposal (74 FR 16448). Instead, EPA revised the Subpart W proposal based on its review of the comments and updated information about monitoring techniques. As a result, EPA issued a proposed rulemaking on April 12, 2010 (75 FR 18608) that would add Subpart W to 40 CFR Part 98 and collect emission data from two additional segments in the petroleum and natural gas source category. EPA also released an Economic Impact Analysis (EIA) in April 2010 that assessed the proposed rulemaking's costs and benefits.[1]

[1] Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Under Subpart W Rule (GHG Reporting); see www.epa.gov/climatechange/emissions/subpart/w.html.

This final EIA presents revised cost estimates that reflect the changes EPA made to the final rule based on its consideration of public comments. Overall, these changes have resulted in a lower cost per metric ton for industry segments to monitor and report emissions compared to the April 2010 proposed rulemaking. The estimated total cost for the petroleum and natural gas source category to comply with the final rule is $61.8 million in the first year. Of this total, it costs $40.1 million to monitor and report about 254 million metric tons of carbon dioxide equivalent ($MtCO_2e$) process emissions, or, on average, $0.16/$MtCO_2e$. This cost compares with the estimate of $0.38/ $MtCO_2e$ under the April 2009 proposal.[2]

Whereas the methodology proposed in April 2009 for Subpart W involved 100-percent measurement for six segments (offshore production, onshore gas processing, transmission, underground storage, liquefied natural gas (LNG) storage and LNG import and export), the April 2010 notice proposed hybrid methodologies to quantify GHG emissions from eight segments in the petroleum and natural gas systems subpart (the original six, plus onshore production and natural gas distribution). Today's rule finalizes the hybrid approach for the eight segments. Notably, it uses limited direct measurement (i.e., only in areas where emissions are known to be significant and not enough reliable data are available to develop emission factors). The bulk of emissions will be quantified using engineering calculations based on actual facility or field data and using leak detection and "leaker" factors[3]. There are also some sources that would use population-based factors—often referred to as default factors—primarily for inaccessible sources or relatively small leaking sources. Consistent with the April 2010 proposed rulemaking and the Technical Support Document (TSD) (EPA-HQ-OAR-2009-0923-0027), the final rule and economic analysis use population-based factors. In addition, EPA finalized the proposal to use the MMS[4] Gulfwide Offshore Activity Data System (GOADS) process for collecting data from offshore production platforms. This approach leverages an existing GHG data collection process and minimizes burden.

Today's final rule includes several key changes that affect compliance cost estimates. First, the final rule provides equipment thresholds on several emission sources. Reporters will

[2] For the final rule, the total cost estimate for the first year includes $18.4 million for non-reporters to make a threshold determination and $3.3 million for combustion emission reporting by reporters. The April 2009 analysis did not include a burden estimate for non-reporters to make a threshold determination.

[3] Leaker factors are developed by actual measurement of leaks from a large population of common fugitive or vented sources; the emission quantification requires actual detection of a leak before application of a factor. This method provides a truer assessment of actual emissions than "population" emission factors, which are based on simple population count. The population count provides an estimate of "potential" emissions because it assumes a percentage of leaking components.

[4] The Minerals Management Service (MMS) has been renamed the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE).

use simple population-based emission factors for sources below the equipment threshold. Second, EPA has simplified the requirement for sampling of gas and emissions for many of the emission sources, thus considerably reducing burden.

Overall, the hybrid methodology finalized in today's rule results in a significant reduction in the compliance cost per metric ton of equipment leak and vented GHG emission reporting, relative to the original proposal. For the six original segments, equipment leak and vented emission costs for reporters changed from \$0.36/MtCO_2e in the April 2009 proposed rule to \$0.28/MtCO_2e in the April 2010 proposal, and to \$0.33/MtCO_2e in the final rulemaking, based on average "first-year" costs. [5,6] These estimates do not account for onshore production and natural gas distribution, the two segments added in the April 2010 proposal. Under the final rule, EPA estimates it will cost reporters on average, in eight segments, \$0.16/MtCO_2e in the first year, which is less than the first year cost of \$0.21/MtCO_2e in the April 2010 proposed rulemaking.

The cost estimates for today's rule also account for the burden to report combustion emissions because some reporters that equal or exceed the Subpart W threshold for equipment leaks and vented emissions would need to report combustion emissions under Subpart C of 40 CFR Part 98. In those cases, the reporters would not have triggered the Subpart C reporting threshold in the absence of Subpart W. Those that meet the emission threshold under Subpart W, however, are required to report combustion emissions under Subpart C, even if the combustion emissions alone do not exceed the Subpart C threshold. In short, EPA expects the addition of Subpart W to the GHG reporting rule to result in the reporting of additional combustion emissions under Subpart C, referred to as "incremental combustion emissions" in this document. Of the 162.2 million MtCO_2e expected to be reported under Subpart C, 83.5 million MtCO_2e are the combustion emissions from petroleum and natural gas facilities that would not have reported in the absence of Subpart W. The incremental combustion emission reporting is \$3.3 million per year of the total combustion emission cost, or \$0.04/MtCO_2e.

First-year costs for Subpart W vented and equipment leak emissions are significantly higher than the "subsequent-year" costs, totaling \$40.1 million in the first year for equipment leaks and vented emission determination, decreasing to \$15.1 million in subsequent years. The higher burden is due to start-up costs in the first year. For example, the rule requires the

[5] The \$0.28 figure was incorrectly stated as \$0.10/metric ton in the April 2010 EIA due to typographical error.

[6] Unless otherwise specified, this document reports all costs in 2006 dollars and the emissions as CO_2e using a 100-year global warming potential from the Intergovernmental Panel on Climate Change (IPCC). Also, subsequent-year costs are the average of costs subsequent to first-year costs and thereby represent a "steady-state" time period.

installation of ports in vent lines for compressors and well equipment in the first year to enable spot measurement of emissions using devices such as vane anemometers. This is a one-time cost associated with reporting start-up; the only cost in subsequent years for those sources is to physically take spot measurements.

Today's rule finalizes the approach in the April 2010 proposal to define vented emissions separately from fugitive emissions, except that it replaces the term "fugitive emissions" with "equipment leak." EPA made this change in response to public comments that "equipment leak" is better understood in the industry. In sum, today's final rule defines emissions from the petroleum and natural gas industry as follows:

1) Vented emissions, which include intentional or designed releases of methane (CH_4) and/or carbon dioxide (CO_2) containing natural gas or hydrocarbon gas (not including stationary combustion flue gas) from emission sources including, but not limited to, open-ended lines, gas pneumatic-powered valves and pumps, equipment depressuring to the atmosphere, and compressor shaft seals.

2) Equipment leaks, which mean those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

3) Flare combustion emissions, which include CH_4, CO_2, and nitrous oxide (N_2O) emissions resulting from combustion of gas in flares.

1.2 Role of the Economic Impact Analysis in the Rulemaking Process

1.2.1 Legislative Authority and Context

This report analyzes the estimated economic impacts of the mandatory reporting program that EPA has developed for Subpart W, in accordance with the FY 2008 Appropriations language, under the authority of Section 114 of the Clean Air Act [CAA]. Section 114 provides EPA broad authority to collect data for the purpose of "carrying out any provision" of the Act (except for a provision of Title II with respect to manufacturers of new motor vehicles or new motor vehicle engines). Section 114(a)[7] of the CAA authorizes the Administrator to, *inter alia,* require certain persons (see below), on a one-time, periodic or continuous basis, to keep records, make reports, undertake monitoring, sample emissions, or provide such other information as the Administrator may reasonably require. This information may be required of any person who (i)

[7] The joint explanatory statement refers to "Section 821 of the Clean Air Act," but Section 821 was part of the 1990 CAA Amendments and was not codified into the CAA itself.

owns or operates an emission source, (ii) manufactures control or process equipment, (iii) the Administrator believes may have information necessary for the purposes set forth in this section, or (iv) is subject to any requirement of the Act (except for manufacturers subject to certain Title II requirements). The information may be required for the purposes of developing an implementation plan, an emission standard under Sections 111, 112 or 129[8], determining if any person is in violation of any standard or requirement of an implementation plan or emission standard, or "carrying out any provision" of the act (except for a provision of Title II with respect to manufacturers of new motor vehicles or new motor vehicle engines)[9].

The scope of the persons potentially subject to a Section 114(a)(1) information request (e.g., a person "who the Administrator believes may have information necessary for the purposes set forth in" Section 114[a]) and the reach of the phrase "carrying out any provision" of the act are quite broad. EPA's authority to request information reaches to a source not subject to the CAA and may be used for purposes relevant to *any* provision of the act. Thus, for example, utilizing Section 114, EPA could gather information relevant to carrying out provisions involving research (e.g., Section 103[g]); evaluating and setting standards (e.g., Section 111); and endangerment determinations contained in specific provisions of the Act (e.g., 202); as well as other programs.

EPA has recently announced a number of climate change related actions, including:

- Final rulemaking with the Department of Transportation (DOT) to limit GHG emissions from light-duty vehicles, "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards," (75 FR 25324, May 7, 2010).

- Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act (74 FR 18886, April 24, 2009).

- Reconsideration of the memo entitled "EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program" (73 FR 80300, December 31, 2008).

- Granting the California Waiver (74 FR 32744, July 9, 2009).

[8] Section 111 of the CAA allows for "standards of performance for new stationary sources"; Section 112 is for "Hazardous Air Pollutants"; and Section 129 contains provisions for "solid waste combustion."

[9] Although there are exclusions in Section 114(a)(1) regarding certain Title II requirements applicable to manufacturers of new motor vehicle and motor vehicle engines, Section 208 authorizes the gathering of information related to those areas.

These are all separate actions. Some are related to EPA's response to the U.S. Supreme Court's decision in Massachusetts v. EPA. 127 S.Ct. 1438 (2007); others are EPA actions to address climate change. The GHG reporting rule and this final rulemaking do not indicate that EPA has made any final decisions on these other actions; however, the mandatory GHG reporting program will provide EPA, other government agencies, and outside stakeholders with economy-wide data on facility-level (and in some cases corporate-level) GHG emissions, which could assist in future policy development.

Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions. Although additional data collection (e.g., for other source categories such as indirect emissions or offsets) will no doubt be required as the development of climate policies evolves, the data collected in this rule will provide useful information for a variety of polices. Furthermore, many existing programs collect this type of information and will continue to do so. Through data collected under this rule, EPA, states, and the public will gain a better understanding of the relative emissions of the petroleum and natural gas industry, and the distribution of emissions from individual facilities within different segments of this industry. The facility-specific data will also improve understanding of the factors that influence GHG emission rates and actions that facilities are already taking to reduce emissions.

The Agency considered a wide range of determining factors when selecting the alternatives for this rule. These included the consideration of costs and benefits, which are essential to making efficient, cost-effective decisions for implementation of these standards. Other important considerations included the language of the Appropriations Act and the accompanying explanatory statement related to source categories; consistency with other CAA or state-level regulatory programs that typically require facility- or unit-level data; the relative accuracy of different monitoring approaches and the monitoring methods already in use within the petroleum and natural gas industry; and the potential burden placed on small businesses associated with a range of reporting thresholds.

This EIA is intended to inform the public about the selection criteria for this rule, which include, but are not limited to, the potential costs and benefits that may result when the mandatory reporting program is implemented.

1.2.2 Role of Statutory and Executive Orders

Several statutes and executive orders dictate the manner in which EPA considers rulemaking and apply to any public documentation. The analysis required by these statutes and executive orders is presented in Section 6.

EPA presents this EIA for Subpart W—Petroleum and Natural Gas Systems—pursuant to Executive Order 12866, the guidelines of Office of Management and Budget (OMB) Circular A-4, and EPA's Economic Guidelines[10]. These documents contain guidelines for assessing the benefits and costs of the selected regulatory option, as well as options that are more stringent or less stringent. Section 4 of the EIA presents the costs of the final rulemaking; Section 5 summarizes the cost-effectiveness analysis of the program and also qualitatively describes the benefits of the final rulemaking.

1.2.3 Illustrative Nature of the Analysis

The analysis illustrates the types of costs and benefits that may accrue as a result of the program. The estimates of costs reflect existing production levels in Subpart W for certain petroleum and natural gas systems. Estimates of emissions are based on 2006 data, with a number of adjustments to reflect best and most current information from published sources (delineated in the TSD). When the reporting program takes effect, actual patterns of economic activity and emissions may differ from current conditions; however, these data provide estimates of baseline conditions and estimated costs of compliance.

1.3 Overview and Design of the Economic Impact Analysis

This EIA comprises seven sections. Following this introductory section, Section 2 describes segments affected by Subpart W provisions and reviews existing reporting programs and how they treat comparable petroleum and natural gas systems. Section 3 describes the development of the rule, including control options and analyses of alternative scenarios. Section 4 characterizes baseline conditions and presents engineering estimates of the costs of complying with Subpart W of the rule. Section 5 presents an assessment of the monitoring and reporting costs for the petroleum and natural gas industry, a qualitative examination of uncertainty related to measurement accuracy of monitoring methods prescribed, and an assessment of potential impacts on small entities. Section 5 also presents a brief qualitative examination of potential benefits of the rule. Section 6 provides a discussion of the Agency's compliance with executive orders and other statutes during the development of the rule. Section 7 describes EPA's conclusions and findings.

1.3.1 Establishing Baseline and Years of Analysis

Data used for the analysis represent the most recent data available on estimates of GHG emissions for the petroleum and natural gas source category, productive capacity, existing

[10] U.S. Office of Management and Budget. Circular A-4, September 17, 2003: http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf.

emission monitoring, and reporting activities for this industry. While EPA recognizes that economic growth and changes in the structure of the economy over time will likely result in changes in both emissions and costs for those covered by Subpart W, attempting to project these changes would lead to an increased level of uncertainty without conveying comparable improvements in the assessment. Thus, EPA uses data representing essentially current conditions as a proxy for conditions present when the rule takes effect. Such estimates are inherently uncertain because data needed for more precise measurements are not available. The data collected by the rule would greatly enhance future estimates.

1.3.2 Developing the GHG Reporting Rule Considered in This Economic Impact Analysis

In order to ensure a comprehensive consideration of GHG emissions, EPA conducted numerous stakeholder meetings, evaluated more than 484 significant and detailed comments (more than 2,700 pages for Subpart W), and conducted extensive review and analysis of available information on segments and specific sources.

EPA examined existing GHG reporting programs prior to developing the rule. Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the rule to analyze how these programs treat emissions from the petroleum and natural gas industry. One of EPA's goals was to develop a reporting rule for Subpart W units that, to the extent possible and appropriate, is consistent with existing GHG emission estimation and reporting methodologies, to reduce the burden of reporting for all parties involved. The TSD documents EPA's review of GHG monitoring protocols for each segment identified by Subpart W that is used by federal, state, regional, and international voluntary and mandatory GHG programs, and EPA's review of state mandatory GHG rules and how they treat equipment leak emissions from the petroleum and natural gas industry.

EPA's overall rulemaking approach began with identifying anthropogenic sources in the U.S. GHG Inventory and Intergovernmental Panel on Climate Change (IPCC). The rule would require reporting of CO_2 and CH_4 equipment leak and vented emissions, as well as combustion-related emissions[11] of CO_2, CH_4, and N_2O as defined in the rule. The IPCC focuses on CO_2, CH_4, and N_2O for both scientific assessments and emission inventory purposes because these are long-lived, well-mixed GHGs not controlled by the Montreal Protocol on Substances that Deplete the Ozone Layer. These GHGs are directly emitted by human activities, are reported annually in

[11] Only flaring emissions are required for reporting under this subpart of the GHG reporting rule. All other combustion-related emissions are to be reported under Subpart C of the finalized GHG reporting rule.

EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, and are the common focus of the climate change research community.

EPA then conducted a review of existing methodologies and reporting programs (e.g., California Air Resources Board [CARB], The Climate Registry [TCR], 1605b of the Energy Policy Act). EPA's review of existing reporting programs and measurement methodologies employed by existing federal and state programs is described in Section II of the 40 CFR Part 98 preamble (74 FR 56260, October 30, 2009). A description specific to petroleum and natural gas can be found in Section C of the TSD. EPA used this information to inform its selection of measurement and reporting methods for this final rulemaking.

Once EPA had a complete list of source categories relevant to the United States, the Agency systematically reviewed those source categories against the following criteria to develop the list of source categories included in the proposal:

(1) Include source categories that emit the most significant amounts of GHGs, while also minimizing the number of reporters.

(2) Include source categories that can be quantified with an appropriate level of accuracy.

EPA identified source categories that would be required to report. EPA then screened sources by several key criteria, looking at the number of reporters versus the coverage of emissions under various thresholds, relevant and appropriate quantification methodologies, quantification accuracy, and administrative burden. Based on the source-level screening activities, EPA then developed possible reporting methodologies for the selected sources. The reporting methodologies identified fall into several categories, including continuous emission monitoring, calculating emissions based on site-specific information, and calculating emissions based on default emission factors. In general, for 40 CFR Part 98, EPA selected a combination of continuous emission monitoring and calculations based on site-specific information.

For Subpart W, the April 2009 proposed rule involved almost exclusive application of detection and direct spot measurement[12] of vented and equipment leak emissions for the six segments (offshore production, onshore natural gas processing, transmission, underground storage, LNG storage and LNG import and export facilities). Both the April 2010 proposed

[12] Direct spot measurement means that the reading is taken only once in the reporting year and through direct measurement using a vane anemometer or similar equipment; the measurement is not "CEMS" (continuous emission monitoring system), as it is not continuous.

rulemaking and final rulemaking include eight segments—the original six plus onshore petroleum and natural gas production and natural gas distribution—and significantly reduce the sources that must be directly quantified. While direct spot measurement is still required to develop site or equipment-specific emission factors for some major sources, much of the emission quantification is through effective but less burdensome use of engineering estimates and leak detection with use of leaker factors and component population count and population (default) emission factors.

Once the Subpart W segments and methodologies had been identified, EPA evaluated different rule options across the following dimensions:

- Threshold (level of emissions below which entities are not required to report):
  - 1,000 MtCO_2e/year
  - 10,000 MtCO_2e/year
  - 25,000 MtCO_2e/year
  - 100,000 MtCO_2e/year
- Methodology for measuring emissions:
  - Direct spot measurement
  - Facility-specific calculation methods
  - Leaker and default emission factors

The Agency examined several options for each dimension to identify the selected option for the rule.

The options and alternatives evaluated are described in detail in Section 3. Section 4 details the engineering cost analysis, which outlines the monitoring and reporting activities and costs for each source under Subpart W that is required to report.

1.3.2.1 Summary of the Major Changes From the April 2009 Proposed Rulemaking to the April 2010 Proposed Rulemaking

EPA received approximately 16,800 public comments on the April 2009 proposed rulemaking for all subparts; more than 1,200 pages of those comments focused on Subpart W. EPA held two public hearings and conducted an unprecedented level of outreach between signature of the proposal and the close of the public comment period. The following are the major changes reflected in the April 2010 proposed rulemaking for Subpart W:

– Two additional petroleum and natural gas system segments were added: onshore production and natural gas distribution. These segments represent the largest (onshore production) and fourth largest (natural gas distribution) segments for equipment leak, vented, and flared emissions in the petroleum and natural gas system source category.

– Under the April 2009 proposed rule for Subpart W, essentially 100 percent of the emissions were monitored using leak detection and direct measurement. In the April 2010 proposed rule, the percentage of total equipment leak and vented emissions directly spot measured was reduced to 6 percent.

– The methodology selected for individual sources in each of the proposed April 2010 rule segments was determined based on the intent to achieve the most cost effective coverage of emissions. Therefore, in some cases accepted engineering estimates based on facility data were used; in others, leak detection coupled with use of average leaking component (i.e. leaker) factors was used (this is more informative data on actual leaks for long-term tracking purposes than emission "population" factors based on component counts).

– Use of population emission factors was proposed in several areas, primarily for minor equipment leak sources and also sources that are inaccessible or excessively burdensome for leak detection. To the degree possible, use of these factors was minimized.

– In the case of offshore production, EPA proposed reporting of existing MMS GOADS emission results for offshore platforms in federal Gulf of Mexico (GoM) waters to avoid redundancy of reporting efforts.[13] EPA also required that facilities not covered by GOADS (state waters and federal non-GoM platforms) use data collection and emission calculation methods in accordance with the BOEMRE GOADS program to reduce burden and make emission reporting consistent across the segment.

[13] Gulf Offshore Activities Data System (GOADS) is an inventory of air emissions from platforms operating in federal waters in the Western Gulf of Mexico, developed by MMS (now called BOEMRE). The MMS mandated that all 2,525 offshore operators in the Gulf of Mexico conduct annual surveys (in 2000 and 2005) of their GHG and other hazardous pollutants. MMS collects activity data from each platform that is then used to estimate emissions. The usual cycle for this data collection effort has been once in every three to four years.

In addition to the Subpart W-specific changes above, the changes affecting all subparts of 40 CFR Part 98 would likewise affect Subpart W reporters. These changes include:

- Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that report less than 25,000 $MtCO_2e$ for five years to cease annual reporting to EPA.

- Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that report less than 15,000 $MtCO_2e$ for three years to cease annual reporting to EPA.

- Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that stop operating all GHG-emitting processes and operations covered by the rule to cease annual reporting to EPA.

- Added a provision in 40 CFR 98.3 for submitting revised annual GHG reports to correct errors.

- Added, in 40 CFR 98.3, an accuracy specification of plus or minus 5 percent for flow meters.

- Excluded research and development (R&D) activities from reporting under 40 CFR part 98 by adding an exclusion in 40 CFR 98.2.

- Revised the requirements of the designated representative in 40 CFR 98.4 to align them with those in 40 CFR 75 (accidental release prevention [ARP] regulations).

- Changed record retention to three years instead of five years for most records (40 CFR 98.3).

- In the recordkeeping section (40 CFR 98.3), clarified the contents of the monitoring plan (called the Quality Assurance Project Plan [QAPP] at proposal).

- Revised several definitions in 40 CFR Part 98, Subpart A to address comments.

Overall, the difference between the estimated annual cost of the April 2010 proposed rulemaking for Subpart W and the estimated annual cost of the April 2009 proposed rule resulted from the addition of two segments to Subpart W and the significant reduction in direct emission spot measurements.

1.3.2.2 Summary of the Major Changes From the April 2010 Proposed Rulemaking to the September 2010 Final Rulemaking

Based on its consideration of comments on the April 2010 proposed rule, EPA incorporated the following changes in the final rule:

- Provide an equipment threshold for separators, and dehydrators such that sources below the equipment threshold use a simplified population emission factor approach and sources above the equipment threshold use actual monitoring.

- Onshore production compressors use emission factor approach for estimating process emissions; actual monitoring is not required.

- Use of emissions factors for all pneumatic devices in onshore production. Also, reporters may count the pneumatic devices in their facilities over a period of three years, beyond which only changes have to be reported.

- Provide an external combustion equipment threshold of 5 mmBtu per hour for onshore production and LDCs. External combustion equipment with a rated heat capacity equal to or less than this equipment threshold only report the type and count of equipment within a facility.

- For onshore production, population emission factors will be applied to major equipment rather than individual components.

- Sampling is not required for estimating combustion emissions, determining the composition of natural gas, or assessing tank vapors; best available estimates are acceptable.

- Allow the use of leak detection equipment, such as organic vapor analyzers and toxic vapor analyzers, in addition to using infrared devices.

These changes significantly reduce burden and simplify emission reporting.

1.3.3 Evaluating Costs and Benefits

To inform the selection of the option for the final rule, EPA conducted an EIA across the dimensions identified in Section 1.3.2. EPA estimated the costs of complying with each of the reporting alternatives and assessed the cost-effectiveness of each alternative by examining the costs per million $MtCO_2e$ reported. This cost-effectiveness metric was considered in combination with other important factors such as the potential impacts on small entities and consistency with other CAA or state-level regulatory programs and monitoring methods already in use within the regulated industries.

1.4 Subpart W Selected Greenhouse Gas Reporting Alternative

The selected option for Subpart W of the mandatory GHG reporting rule is outlined below. Section 5 provides cost comparisons for each alternative evaluated under the following two dimensions. The selected option strikes a balance between impacts on small entities, consistency with other programs, costs incurred by the reporting entities, and emission coverage.

- **Threshold**: 25,000 $MtCO_2e$/year
  - The thresholds for the finalized GHG reporting rule fall generally into three groups: capacity, emissions, or entire source category (“All in”). In Subpart W, a facility that emits 25,000 $MtCO_2e$/year or more reports all sources for which there are methods specified in the rule.
  - Subpart W facilities determine their applicability by comparing their emissions to a threshold of 25,000 $MtCO_2e$/year.
  - Subpart W segments evaluate threshold from an analysis of reported vented and equipment leaks and stationary combustion-based emissions.
- **Methodology**: Combination of direct measurement and source-specific calculation methodologies
  - Direct spot measurement of site- or equipment-specific emission factors from sources at facilities that were deemed to be essential to collect based on the estimated volume of emissions and the lack of effective alternative methodologies or emission factors.
  - Source-specific engineering calculation methods using facility-specific information for other sources at the facility.
  - Source-specific calculation methods for equipment identified to be leaking.
  - Source-specific use of population-based emission factors for minor vented and equipment leaks or inaccessible sources.

SECTION 2
REGULATORY BACKGROUND

The intent of this rule is to collect accurate and timely GHG emission data that can be used to inform future policies. Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the rule, and how these existing programs treat the petroleum and natural gas industry. The reporting program will supplement rather than duplicate other U.S. government GHG programs. EPA outlines the Agency's overall rulemaking approach, sources considered, and summarize the review of GHG monitoring protocols for each petroleum and natural gas system used by federal, state, regional, and international voluntary and mandatory GHG programs, and EPA's review of state mandatory GHG rules below. For example, the monitoring and GHG calculation methodologies for many of the petroleum and natural gas systems are the same as, or similar to, the methodologies contained in state reporting programs. The remainder of the section provides an overview of related existing programs and discusses their relevance in the development of this rule.

2.1 EPA's Overall Rulemaking Approach

In response to the FY 2008 Consolidated Appropriations Amendment, EPA has developed this rulemaking. The components of this development are explained in the following subsections.

2.1.1 Identifying the Goals of the Greenhouse Gas Reporting System

The mandatory reporting program outlined in Subpart W will provide comprehensive and accurate data that 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 EPA does not know at this time the specific policies that will be adopted, the data reported through the mandatory reporting system should be of sufficient quality to support a range of approaches. Also, consistent with the FY 2008 Consolidated Appropriations Amendment, the GHG reporting rule covers a broad range of source categories in the economy; however, this EIA for the final rulemaking is specific to Subpart W, petroleum and natural gas systems.

To these ends, EPA identified the following goals of the mandatory reporting system:

– Obtain data that are of sufficient quality that they 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 minimizing reporting from 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.

2.1.2 Developing the Rule

For Subpart W, EPA evaluated the requirements of existing GHG reporting programs, obtained input from stakeholders, analyzed reporting options, and developed the general reporting requirements and specific requirements for each of the GHG emitting processes listed in Subpart W. In addition, EPA considered public comments it received on both the original April 2009 and April 2010 proposed rulemakings as it determined the reporting requirements issued in today's final rule.

2.1.3 Evaluating Existing Greenhouse Gas Reporting Programs

A number of state and regional GHG reporting systems currently are in place or under development. EPA's goal is to develop a reporting rule that, to the extent possible and appropriate, would rely on similar protocols and formats of the existing programs for petroleum and natural gas systems and, therefore, reduce the burden of reporting for all parties involved. Therefore, EPA performed a comprehensive review of existing voluntary and mandatory GHG reporting programs, as well as guidance documents for quantifying GHG equipment leaks from the petroleum and natural gas source category. These GHG reporting programs and guidance documents specifically related to the petroleum and natural gas source category include:

- U.S. national programs, such as the U.S. GHG inventory, the ARP, Department of Energy (DOE) 1605(b) voluntary registry, and voluntary GHG partnership programs (e.g., Natural Gas STAR).
- State and regional GHG reporting programs, such as The Climate Registry (TCR), the Regional Greenhouse Gas Initiative (RGGI), and programs in California, New Mexico, and New Jersey.
- Reporting protocols developed by nongovernmental organizations, such as the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD).
- Programs from industrial trade organizations, such as the American Petroleum Institute's Compendium of GHG Estimation Methodologies for the Petroleum and Gas Industry.

In reviewing these programs, EPA analyzed the segments covered, thresholds for reporting, the monitoring or emission estimating methods used, the measures to ensure the quality of the reported data, the point of monitoring, data input needs, and information required to be reported and/or retained. EPA analyzed these provisions for suitability to a mandatory, federal GHG reporting program, and compiled the information. Section 2.3 describes the existing reporting programs examined regarding Subpart W. The full review of existing GHG reporting programs and guidance for all GHG reporting rule subparts may be found in the docket at EPA-HQ-OAR-2008-0508-054.

2.1.4 Conducting Stakeholder Outreach to Identify Reporting Issues

Early in the development process of the GHG reporting rule, EPA conducted a proactive communications outreach program to inform the public about the rule development effort. EPA solicited input and maintained an open-door policy for those interested in discussing the rulemaking. Since January 2008, EPA staff has held more than 100 meetings with stakeholders, including the following:

- Trade associations and firms in potentially affected industries/segments.
- State, local, and tribal environmental control agencies and regional air quality planning organizations.
- State and regional organizations already involved in GHG emission reporting, such as TCR, California Air Resources Board (CARB), and Western Climate Initiative (WCI).
- Environmental groups and other nongovernmental organizations.
- U.S. Department of Interior, which has a program relevant to GHG emissions.

During the meetings, EPA shared information about the statutory requirements and timetable for developing a rule and encouraged stakeholders to provide input on key issues. Examples of topics discussed included existing GHG monitoring and reporting programs and lessons learned, thresholds for reporting, schedules for reporting, scope of reporting, handling of confidential data, data verification, and the role of states in administering the program. As needed, the EPA technical workgroups followed up with these stakeholder groups on a variety of methodological, technical, and policy issues. EPA staff also provided information to tribes through conference calls with different Indian tribal working groups and organizations at EPA as well as through individual calls with tribal board members of TCR.[14]

On April 10, 2009 (74 FR 16448), EPA proposed the GHG reporting rule. EPA held two public hearings and received more than 16,000 written public comments. The public comment period ended on June 9, 2009. Subpart W received comments from more than 80 entities with over 1,200 pages of comments, recommendations, and alternatives for consideration.

In addition to the public hearings, EPA had an open-door policy, similar to the outreach conducted during the development of the proposal. As a result, EPA met with more than 4,000 people and 135 groups between proposal signature (March 10, 2009) and the close of the comment period (June 9, 2009). Details of these meetings are available in the docket (EPA-HQ-OAR-2009-0923).

2.1.5 Considering Public Comments on Key Reporting Issues

EPA considered public comments submitted to the docket and those presented at hearings as it finalized the reporting requirements. In the context of the April 2010 proposed rulemaking process, EPA held one public hearing and received more than 40 substantive written public comments. Most comments supported changes made in the proposed rule published on April 9, 2010; however, various commenters expressed concern about the inclusion of the Onshore Production and Local Distribution segments and stated that the scope and cost burden of the proposal would be significantly exceed the costs estimated by EPA. In addition, many commenters suggested changes in methodology or quantification, which EPA incorporated into the final rule. For example, consistent with several commenters' recommendations, EPA has provided flexibility in the types of leak detection equipment required to monitor emissions. See the preamble of today's final rule for a complete discussion of these changes.

2.1.6 Analyzing Emissions From the Petroleum and Natural Gas Industry

For each of the petroleum and natural gas system segments mentioned in Section 2.2, EPA compiled information on current conditions in the segment, including information about existing monitoring equipment or reporting frameworks, estimated emissions of GHGs, and estimated productive capacity or throughput. Section 4 summarizes the incremental costs of measuring vented and equipment leak GHG emissions and conducting reporting activities for Subpart W facilities. Section 5 presents cost scenarios that vary the conditions of the reporting rule for Subpart W with respect to the size of the entity required to report and the type of

[14] For a full list of organizations EPA met with when developing this rule, please see the EPA docket memo, EPA-HQ-OAR-2008-0508-055.

measurement required of the petroleum and natural gas segment. The scenarios specific to Subpart W are listed in Section 3. EPA also reviewed the benefits to stakeholders, including the public, the government, and industry, of a reporting system for petroleum and natural gas emissions in a qualitative analysis. These benefits are outlined in Section 5.

2.2 Sources Considered

A technical subgroup on vented and equipment leak emissions considered the following sources of emissions from the petroleum and natural gas industry, as shown in Table 2-1. Using screening criteria based on the feasibility of monitoring, verifying, and measuring these sources, the technical subgroup developed reporting methodologies for the sources in Subpart W identified in Table 2-2.

Table 2-1 Sources of GHG Emissions Considered

Source	Subpart W: GHG Emissions Considered
Downstream	
Direct emitters	**Stationary and portable combustion**: Sources considered include stationary combustion units (e.g., drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters).
	Vented emissions: Intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas) that result from the extraction, processing, storage, and transport of fossil fuels to the point of final use. Examples include compressor seal vents, storage tank vents, or pneumatic device emissions.
	Equipment leaks: Emissions that are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Examples include leaks from valves and connectors.
	Flare combustion: Unburned hydrocarbons, including CH_4, CO_2, and N_2O emissions resulting from the incomplete combustion of gas in flares from the extraction, processing, storage, and transport of fossil fuels to the point of final use.

Table 2-2 Segments Included in the Petroleum and Natural Gas Regulatory Analyses

Subpart W Segments
Onshore petroleum and natural gas production
Offshore petroleum and natural gas production
Natural gas transmission
Natural gas processing
Natural gas underground storage
LNG storage
LNG import & export terminals
Natural gas distribution

2.3 How the Mandatory GHG Reporting Program Is Different From the Federal and State Programs EPA Reviewed

The various existing state and federal programs EPA reviewed are diverse. They have different thresholds, require different pollutants and different types of emission sources to be reported, rely on different monitoring protocols, and require different types of data to be reported, depending on the purposes of each program. None of the existing programs require nationwide, mandatory GHG reporting by facilities in a large number of segments, so EPA's mandatory GHG rule is unique in this regard. The remainder of this section focuses on existing state and federal programs that apply to petroleum and natural gas systems covered under Subpart W.

Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the rule. Documentation of EPA's review of GHG monitoring protocols for each source category used by federal, state, and international voluntary and mandatory GHG programs, and EPA's review of state mandatory GHG rules can be found at EPA-HQ-OAR-2008-0508-056. The monitoring and GHG calculation methodologies for many source categories are the same as, or similar to, the methodologies contained in state reporting programs such as TCR, the California Climate Action Registry (CCAR), and state mandatory GHG reporting rules and similar to methodologies developed by EPA voluntary programs such as Climate Leaders. Similarity in methods will help maximize the ability of individual reporters to submit the emission calculations to multiple programs, if desired. EPA will continue to work closely with states and state-based groups to ensure that the data management approach in this rule will lead to efficient submission of petroleum and natural gas data to multiple programs.

The intent of this rule is to collect a reasonable estimate of GHG emission data that can be used to inform future policy decisions. One goal in developing the rule is to be consistent with the GHG protocols and requirements of other state and federal programs, where appropriate, in order to make use of existing cooperative efforts and reduce the burden to petroleum and natural gas facilities submitting reports to other programs. EPA also needs to be sure, however, that the mandatory GHG reporting rule collects facility-specific vented and equipment leaks data of sufficient quality to achieve the Agency's objectives. Therefore, some reporting requirements of this rule related to petroleum and natural gas equipment leaks are different from other federal and state programs.

2.3.1 Inventory of U.S. Greenhouse Gas Emissions and Sinks

The U.S. greenhouse gas inventory, prepared by EPA's Office of Atmospheric Programs in coordination with the Office of Transportation and Air Quality, is an impartial, policy-neutral report that tracks annual GHG emissions. The annual report presents historical U.S. emissions of CO_2, CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

The United States submits the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The UNFCCC treaty, ratified by the United States in 1992, sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The United States has submitted the GHG inventory to the United Nations every year since 1993. The annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is consistent with national inventory data submitted by other UNFCCC parties and uses internationally accepted methods for its emission estimates.

In preparing the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, EPA leads an interagency team that includes DOE, the U.S. Department of Agriculture (USDA), the Department of Transportation (DOT), the Department of Defense (DOD), and the State Department. EPA collaborates with hundreds of experts representing more than a dozen federal agencies, academic institutions, industry associations, consultants, and environmental organizations. The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is peer-reviewed annually by domestic experts and by UNFCCC, undergoes a 30-day public comment period, and is peer reviewed annually by UNFCCC review teams.

The *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is a comprehensive, top-down national assessment of national GHG emissions and uses top-down national energy data and other national statistics. To achieve the goal of comprehensive national emission coverage for reporting under the UNFCCC, most GHG emissions in the report are calculated via activity data from national-level databases, statistics, and surveys. The use of the aggregated national data means that the national emission estimates are not broken down at the geographic or facility level. In contrast, this reporting rule focuses on bottom-up data and individual sources above appropriate thresholds.

The inventory contains estimates of vented emissions, equipment leaks, and combustion emissions from petroleum systems and from natural gas systems, which are both IPCC source categories. Regarding the quantification of CH_4 emissions from natural gas systems, reductions achieved through the Natural Gas STAR program and National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations are included (see below for more details on these programs). A detailed study by the Gas Research Institute (GRI)[15] and EPA (GRI/EPA 1996) is used as the basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry in the report.

For petroleum and natural gas systems, EPA has been aware that there are a number of areas where the 2008 U.S. Greenhouse Gas Inventory Report assumptions may substantially underestimate actual emission levels. The final rule for Subpart W is estimated to significantly increase the level of emissions covered than are included in the 2008 U.S. Greenhouse Gas Inventory Report by reflecting improved estimates of emissions from key sources such as well liquid unloadings, well workovers, well completions and compressor wet seal degassing vents. These estimates are based on publicly available information from the EPA Natural Gas STAR Web site and assumptions based on expert judgment.

The final rule for Subpart W will therefore help to improve the development of future national inventories for petroleum and natural gas systems by improving the estimates of emissions and thereby advance the understanding of emission processes and monitoring methodologies. Facility, unit, and process level GHG emission data for all sources will improve the accuracy of future U.S. Greenhouse Gas Inventory Reports by confirming the national statistics and emission estimation methodologies used to develop the top-down inventory. The results can confirm shortcomings in the national statistics and identify where adjustments may be needed.

[15] Now the Gas Technology Institute

Therefore, although the data collected under this rule will not replace the system in place to produce the comprehensive annual national inventory, it can serve as a useful tool to better improve the accuracy of future national-level inventories.

2.3.2 Federal Voluntary Greenhouse Gas Programs

EPA and other federal agencies operate a number of voluntary GHG reporting and reduction programs that EPA reviewed when developing this proposal, including several non-CO_2 voluntary programs, and the DOE 1605(b) voluntary GHG registry. Several other federal voluntary programs encourage emission reductions, clean energy, or energy efficiency; this summary does not cover them all (for additional information see *Review of Existing Programs,* EPA-HQ-OAR-2008-0508-054). This summary focuses on programs that include voluntary GHG emission inventories or reporting of GHG emission reduction activities for sources that were considered for inclusion in Subpart W of this final rulemaking.

2.3.2.1 Non-CO_2 Voluntary Partnership Programs

Since the 1990s, EPA has operated a number of non-CO_2 voluntary partnership programs aimed at reducing emissions from GHGs such as CH_4, SF_6, and PFCs. There are four segment-specific voluntary methane reduction programs: Natural Gas STAR, Landfill Methane Outreach Partnership (LMOP), Coalbed Methane Outreach Programs (CMOP), and Ag STAR. In addition, there are segment-specific voluntary emission reduction partnerships for high-global-warming-potential gases. The program specific to those entities that fall under Subpart W is the Natural Gas STAR partnership, which encourages companies across the natural gas and petroleum industries to adopt practices that reduce methane emissions. Industry partners voluntarily provide technical information on projects they undertake to reduce methane emissions on an annual basis, but they do not submit methane emission inventories.

2.3.2.2 1605(b) Voluntary Registry

The DOE Energy Information Administration established a voluntary GHG registry under Section 1605(b) of the Energy Policy Act of 1992. The program was recently enhanced and a final rule containing general reporting guidelines was published on April 21, 2006 (71 FR 20784); the rule is contained in 10 CFR Part 300. Unlike EPA’s proposal, which requires reporting of GHG emissions from facilities over a specific threshold, the DOE 1605(b) registry allows anyone (e.g., a public entity, private company, or an individual) to report their emissions and their emission reduction projects to the registry. Large emitters (e.g., anyone that emits over 10,000 $MtCO_2e$ per year) who wish to register emission reductions must submit annual company-wide GHG emission inventories following technical guidelines published by DOE and must calculate and report net GHG emission reductions. The program offers a range of reporting methodologies from stringent direct measurement to simplified calculations using default factors and allows the reporters to report using the methodological option they choose. For the petroleum and natural gas industry, some methods for estimating emissions are outlined, but this petroleum and natural gas section in the 1605(b) *Technical Guidelines* is only meant to serve as a guide. Reporters can use established, published authorities' estimation methods, which must be referenced. In addition, as mentioned previously, unlike EPA's proposal, sequestration and offset projects can also be reported under the 1605(b) program. There is additional flexibility offered to small sources, which is that they can choose to limit annual inventories and emission reduction reports to a single type of activity rather than reporting company-wide GHG emissions, but they must still follow the technical guidelines. Reported data are made available on the Internet in a public-use database.

2.3.2.3 Summary

These voluntary programs are different in nature from the mandatory GHG reporting rule. Industry participation in the programs and reporting to the programs is entirely voluntary. A small number of sources report, compared to the number of facilities that will likely be affected by Subpart W of the mandatory GHG reporting rule. Most of the EPA voluntary programs do not require reporting of annual emission data, but are instead intended to encourage GHG reduction activities and track partners' successes in implementing such projects.

At the same time, aspects of the voluntary programs serve as useful starting points for the mandatory GHG reporting rule. GHG emission calculation principles and protocols have been developed for various types of emission sources by Climate Leaders, the DOE 1605(b) program, and some partnerships such as the SF_6 reduction partnerships and SmartWay. Under these protocols, reporting companies monitor process or operating parameters to estimate greenhouse emissions, report annually, and retain records to document their GHG estimates. Through the voluntary programs, EPA, DOE, and participating companies have gained understanding of processes that emit GHGs and experience in developing and reviewing GHG emission inventories.

2.3.3 Federal Mandatory Reporting Programs

2.3.3.1 Toxics Release Inventory

The Toxics Release Inventory (TRI) requires facility-level reporting of annual mass emissions of approximately 650 toxic chemicals. When facilities—in a wide range of industries, such as manufacturing industries and the petroleum industry—emit these chemicals above established thresholds, they report. Facilities must submit annual reports of total stack and equipment leaks of the listed toxic chemicals using a standardized form that can be submitted electronically. No information is reported on the processes and emission points included in the total emissions. The data reported to TRI are not directly useful for the GHG rule because TRI does not include GHG emissions and does not identify processes or emission sources. The TRI program is similar, however, to the mandatory GHG reporting rule in that it requires direct emission reporting from a large number of facilities (roughly 23,000) across all major industrial segments. Therefore, EPA reviewed the TRI program for ideas regarding program structure and implementation.

2.3.4 Other EPA Emission Inventories

2.3.4.1 National Emissions Inventory

EPA compiles the National Emissions Inventory (NEI), a database of air emission information provided primarily by state and local air agencies and tribes. The database contains information on stationary and mobile sources that emit criteria air pollutants and their precursors, as well as hazardous air pollutants. Stationary point source emissions that must be inventoried and reported are those that emit over a threshold amount of at least one criteria pollutant. Many states also inventory and report stationary sources that emit amounts below the thresholds for each pollutant. The point sources that NEI includes number more than 60,000 facilities. Required point source information consists of facility identification information as well as process information detailing the types of air pollution emission sources, air pollution emission estimates (including annual emissions), control devices in place, stack parameters, and location information. The NEI differs from the GHG reporting rule in that the NEI contains no GHG data, and the data are reported primarily by state agencies rather than directly reported by industries. In developing the rule, however, EPA used the NEI to help determine sources that might need to report under Subpart W of the GHG reporting rule. EPA considered the types of facility and process and activity data reported in NEI to support the emission data as a possible model for the types of data to be reported under the GHG reporting rule.

2.3.5 State and Regional Voluntary Programs for Greenhouse Gas Emission Reporting

A number of states have demonstrated leadership and developed corporate voluntary GHG reporting programs individually or joined with other states to develop GHG reporting programs as part of their approaches to addressing GHG emissions. The following discussion summarizes two prominent voluntary efforts. In developing the GHG rules, EPA reviewed the relevant protocols used by these programs as a starting point. The Agency recognizes that these programs may have additional monitoring and reporting requirements than those outlined in the rule in order to provide distinct program benefits.

2.3.5.1 California Climate Action Registry

CCAR is a voluntary GHG-registry already in use in California. CCAR has released several methodology documents, including a general reporting protocol, general certification (verification) protocol, and several segment-specific protocols. Companies submit emission reports using a standardized electronic system. Emission reports may be aggregated at the company level or reported at the facility level. CCAR is transitioning out of entity-emission reporting; 2009 will be the last year it accepts such reporting. Emission reporting can instead be conduced under CCAR’s sister organization The Climate Registry (TCR), which is based off of CCAR’s work. A number of members of CCAR have already made the transition over to TCR.

2.3.5.2 The Climate Registry

TCR is a partnership formed by U.S. and Mexican states, Canadian provinces, and tribes to develop standard GHG emission measurement and verification protocols and reporting system capable of supporting mandatory or voluntary GHG emission reporting rules and policies for its member states. TCR has released a final General Reporting Protocol that contains procedures to measure and calculate GHG emissions from a wide range of source categories. It has also released a general verification protocol and an electronic reporting system. Several industry-specific draft protocols have been released recently for public comment, including *Petroleum & Gas Exploration & Production Protocol* and a verification protocol for this segment. Founding reporters (companies and other organizations that have agreed to voluntarily report their GHG emissions) implemented a pilot reporting program in 2008. Annual reports will be submitted covering six GHGs. Corporations must report facility-specific emissions broken out by type of emission source (e.g., stationary combustion, mobile combustion, process, equipment leak and indirect) and gas (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6) within each facility.

2.3.6 State and Regional Mandatory Programs for Greenhouse Gas Emission Reporting and Control

Several individual states and regional groups of states have demonstrated leadership and are developing or have developed mandatory GHG reporting programs and GHG emission control programs. This section summarizes two regional cap and trade programs and several state mandatory reporting rules, which cover—or, for those programs still under development, have the potential to cover—the petroleum and natural gas segment. EPA recognizes that, like the current voluntary regional and state programs, state and regional mandatory reporting programs may evolve or develop to include additional monitoring and reporting requirements than those included in the rule. In fact, these programs may be broader in scope or more aggressive in implementation because the programs are either components of established reduction programs (e.g., cap and trade) or being used to design and inform specific measures that indirectly reduce GHG emissions (e.g., energy efficiency).

2.3.6.1 Regional Greenhouse Gas Initiative

RGGI is a regional cap and trade program that covers CO_2 emissions from electric generating units (EGUs) larger than 25 megawatts (MW) in member states in the Mid-Atlantic and Northeast. The program goal is to reduce CO_2 emissions to 10 percent below 1990 levels by the year 2020. Certain types of offset projects will be allowed, and GHG offset protocols have been developed. The states participating in RGGI have adopted state rules (based on a model rule) to implement RGGI in each state. The RGGI cap and trade program took effect on January 1, 2009. There has been some discussion of regulating additional sources of GHG emissions under the RGGI program in the future.

2.3.6.2 Western Climate Initiative

WCI is another regional cap and trade program being developed by a group of western states and Canadian provinces. The goal is to reduce GHG emissions to 15 percent below 2005 levels by the year 2020. Draft options papers and program scope papers were released in early 2008, public comments were reviewed, and final program design recommendations were made in September 2008. Other elements of the program, such as reporting requirements, market operations, and offset program development continue. WCI released its final version of the first group of Essential Requirements for Mandatory Reporting (ERMR) in July 2009, and it is anticipated that WCI jurisdictions will have rules implementing these reporting requirements in place for the 2010 reporting year or shortly thereafter. Petroleum and natural gas production facilities are not listed in the first reporting group, although petroleum refiners must report. Several source categories are being considered for inclusion in the cap and trade framework. One such category is “industrial process emission sources, including petroleum and natural gas process emissions”[16], meaning that sources covered under Subpart W of the federal reporting rule may also be regulated under a future WCI program. The program might be phased in, starting with a few source categories and adding others over time. Points of regulation for some source categories, calculation methodologies, and other reporting program elements are under

[16] In the WCI design recommendations, process emissions are defined as including emissions from chemical, biological, and other non-combustion processes. These emissions may be deliberate (e.g., vented), fugitive (e.g., leaked), or accidental.

development. WCI is also analyzing alternative or complementary policies other than cap and trade that could help reach GHG reduction goals. Options for rule implementation and for coordination with other rules and programs such as TCR are being investigated.

2.3.7 State Mandatory Greenhouse Gas Reporting Rules

Seventeen states have developed, or are developing, mandatory GHG reporting rules.[17] The docket for 40 CFR Part 98 (74 FR 56260, October 30, 2009) contains a summary of these state mandatory rules (EPA-HQ-OAR-2008-0508-056). Final rules have not yet been developed by some of the states, so details of some programs are unknown. Reporting requirements have already entered into effect in 12 states as of 2009; the rest will begin between 2010 and 2012. Reporting is typically annual, although some states require quarterly reporting for EGUs, consistent with RGGI.

State rules differ with regard to which facilities must report and which GHGs must be reported. Some states require all facilities that must obtain Title V permits to report GHG emissions. Others require reporting for particular segments (e.g., large EGUs, cement plants, refineries). Some state rules apply to any facility with stationary combustion sources that emit a threshold level of CO_2. Some apply to any facility, or to facilities within listed industries, if their emissions exceed a specified threshold level of CO_2e. Many of the state rules apply to six GHGs covered by 40 CFR Part 98 (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6); others apply only to CO_2 or a subset of the six gases. Most require reporting at the facility level, or by unit or process within a facility.

The level of specificity regarding GHG monitoring and calculation methods varies. Some of the states refer to use of protocols established by TCR or CCAR, to industry-specific protocols (such as methods developed by the American Petroleum Institute [API]), to accepted international methodologies such as IPCC, and/or to emission factors in EPA's *Compilation of Air Pollutant Emission Factors* (known as AP-42) or other EPA guidance.

2.3.7.1 California Mandatory Greenhouse Gas Reporting Rule

The CARB mandatory reporting rule is an example of a state rule that covers multiple source categories and contains relatively detailed requirements, similar to this proposal developed by EPA. The regulation became effective on January 2, 2009. According to CARB, selected facilities (e.g. general stationary combustion facilities outside the petroleum-and-gas segment, and electricity generation and cogeneration plants not within the operational control of

[17] These are California, Colorado, Connecticut, Delaware, Hawaii, Iowa, Maine, Maryland, Massachusetts, New Jersey, New Mexico, North Carolina, Oregon, Virginia, Washington, West Virginia, and Wisconsin.

larger facilities and entities) are required to have filed their first emission data reports by April 1, 2009. The rest of the facilities and entities are to have reported by June 1, 2009 (see www.arb.ca.gov/cc/reporting/ghg-rep/ghgschedadvisory.pdf). The rule requires facility-level reporting of all GHGs (except PFCs) from cement manufacturing plants, electric power generation and retail markets, cogeneration plants, petroleum refineries, hydrogen plants, and facilities with stationary combustion sources emitting greater than 25,000 $MtCO_2$ per year. The California rule does not impact those facilities that would be subject to reporting under Subpart W of the federal reporting rule. Part 75 (Acid Rain Program) data will be used for EGUs. The regulation contains specific GHG estimation methods that are largely consistent with CCAR protocols and also relies on API protocols and IPCC/European Union protocols for certain types of sources. California continues to participate in other national and regional efforts, such as TCR and WCI, to assist with developing consistent reporting tools and procedures on a national and regional basis.

SECTION 3
DEVELOPMENT OF THE MANDATORY GHG REPORTING RULE

To develop Subpart W of the Mandatory GHG Reporting Rule, EPA considered various dimensions of the reporting program and developed and evaluated several options for each dimension. After a preliminary evaluation of the options for each dimension, a recommended reporting program alternative was selected. Several possible program alternatives were selected, generally by varying one dimension at a time, while retaining the recommended option for the other dimensions. These alternatives were then evaluated based on estimated cost, cost-effectiveness (cost per metric ton of emissions reported), and estimated impacts on small entities. This process is discussed in greater detail in the following sections.

3.1 Rule Dimensions for Which Options Were Identified

Possible designs for Subpart W of the Mandatory GHG Reporting Rule were developed by varying options across two dimensions:

1. **Thresholds**: Based on the discretion in the language of the appropriations bill that calls for emission reporting above appropriate thresholds in all segments of the economy, EPA has identified an appropriate threshold above which petroleum and natural gas facilities are required to report their GHG emissions. Types of thresholds considered were production or productive capacity, and emissions-based.

2. **Measurement Methodology**: To be able to report their GHG emissions, facilities will be required to measure them using an appropriate methodology. Generally, measurement methodologies may be based on instrumentation and direct measurement, or on calculation methods based on other data available to the facility (e.g., activity data and emission factors).

The options EPA considered for each dimension for Subpart W sources are discussed in the following sections and summarized in Table 3-1. The table shows the combinations of options for specific dimensions. EPA conducted cost analysis for the combinations marked by X; the shaded box represents the final option.

Table 3-1 Options Considered in Developing Scenarios for Regulation Under Subpart W (Final Option Indicated by Shading)

Methodology / Threshold	Direct Measurement (CEMS)	Hybrid: Direct spot measurement for major emission sources and calculation methods for non-major sources	Default emission factors from EPA
Capacity-based			
Emissions based 1,000 $MtCO_2e$	X	X	X
Emissions-based 10,000 $MtCO_2e$	X	X	X
Emissions-based 25,000 MtCO2e	X	X	X
Emissions-based 100,000 MtCO2e	X	X	X
Hybrid: 25,000 $MtCO_2e$ unless already reporting based on capacity under another program			

3.1.1 Thresholds

Three options were considered in setting the threshold above which reporting of GHG emissions will be required for Subpart W: capacity-based thresholds, emission-based thresholds, or a hybrid of the two. Within each option, various definitions and levels of the threshold were examined. EPA also considered capacity-based and hybrid threshold approaches in the preliminary phases of the analysis but did not include them in the final cost analysis. As explained in the following sections, EPA ruled out these two options based on data limitations and other challenges.

3.1.1.1 Option 1: Capacity-Based Threshold

A capacity-based threshold would be defined based on the emitting facility's throughput, production, or productive capacity. In defining the capacity-based threshold, EPA considered that using a source-level capacity measure for the threshold might be a more straightforward way for facilities to know that they must report their GHG emissions, but the data on source-level capacity are not currently universally available to EPA.

3.1.1.2 Option 2: Emission-Based Threshold (Selected)

Option 2 involves the use of actual facility-level emissions of GHGs, measured in $MtCO_2e$. Various levels were considered, ranging from 1,000 $MtCO_2e$ to 100,000 $MtCO_2e$. Obviously, lower thresholds would require more facilities to participate in the reporting program. Given current data availability, an emission-based threshold will generally focus on larger, emission-intensive sources in the petroleum and natural gas segment for which emission data are readily calculated or measured.

3.1.1.3 Option 3: Hybrid Threshold

The hybrid threshold option is a combination of three general groups: capacity, emissions, or entire source category ("all in"). The thresholds developed are generally equivalent to a facility-wide threshold of 25,000 $MtCO_2e$ per year of actual emissions. The preference is to establish thresholds for as many source categories as possible based on a capacity metric; for example, tons of product produced per year. A capacity-based threshold is least burdensome because a facility would not have to estimate emissions to determine if the rule applies. EPA faces two key challenges in trying to develop capacity thresholds, however. First, in most cases, especially involving equipment leak and vented emissions under Subpart W, data are insufficient to determine an appropriate capacity threshold. Second, in many of the petroleum and natural gas segments, the level of emissions from vented and equipment leaks are not related to capacity or throughput. Rather, emissions may be driven by design and operating factors. As an example, pneumatic controls on petroleum and natural gas facilities are designed to vent natural gas to drive valve movements. The level of venting is not dependent on throughput.

3.1.2 Measurement Methodology

EPA identified three measurement methodology options, ranging from installing emission monitoring equipment on all sources under Subpart W to using default emission factors to estimate emissions. The measurement methodology options considered for Subpart W sources are discussed in the following sections.

3.1.2.1 Option 1: Direct Measurement for All Reporters

This option would apply direct measurement requirements to all reporters. It would require facilities subject to Subpart W to use fuel-flow meters for gaseous fuels and for spot measurement of vented emissions from various equipment. In addition, it would require spot detection and quantification of equipment leaks by use of calibrated bagging or high-volume samplers throughout all segments. This option was the selected option for the proposed rule for Subpart W (74 FR 164888, April 10, 2009).

3.1.2.2 Option 2: Hybrid of Direct Measurement and Facility-Specific Calculation for Other Sources (Selected)

EPA's final rule required measurement methodology option for Subpart W is a hybrid of direct measurement and facility-specific calculations, which is considerably less burdensome than Option 1. Specifically, EPA requires the use of direct spot measurement, where reliable emission factors do not exist, as well as engineering calculations based on site-specific information to estimate emissions from the largest emission sources. Other sources will be quantified through the use of leak detection and application of emission factors for leaking equipment (i.e. "leaker" factors). Use of population count and default population emission factors is required for smaller and inaccessible sources.

The hybrid approach results in a significantly lower cost burden to reporting parties yet provides a much more robust development of GHG emissions. Unlike Option 3, which is described in the section the follows, Option 2 will enable EPA to monitor year-to-year changes in emission levels from the petroleum and natural gas source category.

3.1.2.3 Option 3: Default Emission Factor Calculation for Both Combustion and Process Emissions

Under Option 3, EPA would require petroleum and natural gas facilities to base their reported emissions on simplified calculations performed at the facility level, based on EPA-provided default population factors combined with the type of process, production rate, and/or the quantity of fuel/chemical inputs used.

3.2 Selected Option

As described previously, EPA evaluated a variety of options for each dimension of the GHG reporting program and selected a recommended option for each dimension. A summary of the recommended option for each dimension is provided as follows:

- **Threshold**: Emission-based approach
  - For Subpart W sources, applicability is based on emissions. Emissions are the sum of vented emissions and equipment leaks, stationary and portable combustion emissions, as well as emissions from any other source category covered by the finalized GHG reporting rule that may be present at the facility. A facility that emits 25,000 $MtCO_2e$/year or more reports all sources for which there are methods in the finalized GHG reporting rule and final rule for Subpart W.

- For several segments in Subpart W, it was determined appropriate to require the threshold calculation by defining "facility" differently:

    - For onshore petroleum and natural gas production, the facility is defined as the equipment covered in the April 2009 proposed rule and owned or operated by a single entity, as defined by the holder of a drilling or operating permit, located in a hydrocarbon basin. If a drilling or operating permit is not required, then the reporter is the entity that pays the taxes. EPA also analyzed the same facility definition, but as applied to a hydrocarbon field, as opposed to a hydrocarbon basin. As described in the preamble, the threshold determination and cost burden is required based on the basin level approach.

    - For natural gas distribution, a facility is defined as the local distribution company (LDC). Therefore, the threshold is based on total company level emissions of the LDC.

- **Methodology**: A combination of direct measurement and source-specific calculation methodologies

    - For the Subpart W final rule, EPA is requiring the use of direct spot measurement and/or engineering calculations using site-specific information to estimate emissions from the largest emission sources. In addition, sources that are smaller, or are inaccessible for direct measurement, will be quantified through the use of leak detection and application of leaker emission factors for leaking equipment. Population count and population emission factors will be used for smaller and inaccessible sources.

    - EPA also requires source-specific calculation methods using facility-specific information for other sources in the finalized GHG reporting rule present at the facility subject to the Subpart W final rule.

3.3 Alternative Scenarios Evaluated

EPA developed alternative reporting scenarios and assessed the costs and emissions associated with each. As part of the April 2009 proposal, alternative scenarios were developed by creating the recommended scenario (the shaded option in Table 3-1), then varying the levels in one dimension while keeping the other three dimensions at the recommended options. The alternative reporting scenarios evaluated for the Subpart W final rule are listed as follows:

1. A 1,000-$MtCO_2e$ threshold; hybrid methodology
2. A 10,000-$MtCO_2e$ threshold; hybrid methodology
3. A 25,000-$MtCO_2e$ threshold; hybrid methodology
4. A 100,000-$MtCO_2e$ threshold; hybrid methodology
5. A 25,000-$MtCO_2e$ threshold; direct techniques (CEMS, flow meters, calibrated bagging, and high volume sampler) used to measure emissions
6. A 25,000-$MtCO_2e$ threshold; default emission factors (simplified methods) used to measure emissions

The evaluation of the alternative reporting scenarios will allow policymakers, regulated entities, and the general public to see the impact of each variation and assess their cost compared to the required option. Total costs, emissions, and cost-effectiveness of the alternative reporting scenarios for the petroleum and natural gas industry pursuant to Subpart W are discussed in Section 4.

3.4 Data Quality for This Analysis

EPA gathered existing data from EPA, industry trade associations, states, and publicly available data sources (e.g., labor rates from the Bureau of Labor Statistics [BLS]) to characterize the processes, sources, segments, and facilities affected. Costs were estimated based on the data collected and engineering analysis and models provided by EPA and its contractors. EPA staff and contractors provided engineering expertise, knowledge of existing facility conditions and activities, and an estimate of incremental activities required to comply with the rule. Existing models, such as EPA's CEMS cost model, were used for Subpart W to ensure consistency of cost inputs and assumptions.

The most important elements affecting the data quality for this analysis include the number of affected facilities in each source category, the number and types of production processes that emit GHGs, process inputs and outputs (especially for monitoring procedures that involve a carbon mass balance), and the measurements that are already being made for reasons not associated with the Subpart W final rule (to allow only the incremental costs to be estimated). The background information for standards development, often collected from petroleum and natural gas industry surveys, was supplemented from numerous sources, including industry surveys from the U.S. Census Bureau, trade associations, and operating permits. Information on measurements that are already made (and thus would not be associated with the rule) was obtained from discussions with industry representatives, knowledge gained from previous site visits, and other sources. The data collected to characterize the facilities in the Subpart W final rule are judged to be of good quality and the best that are publicly available.

Other elements affecting the quality of the data include estimates of labor hours to perform specific activities, cost of labor, and cost of monitoring equipment. Estimates of labor hours were based on previous analyses of the costs of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored for Subpart W; and engineering judgment. Labor costs were taken from BLS and adjusted to account for overhead. Monitoring costs were generally based on cost algorithms or approaches that had been previously developed, reviewed, accepted as adequate, and used specifically to estimate the costs associated with various types of measurements and monitoring. The data quality associated with these elements of the cost analysis is analogous to the quality of data used in the development of numerous other Information Collection Requests.

SECTION 4
ENGINEERING COST ANALYSIS

4.1 Introduction

EPA estimated costs for each facility under Subpart W to comply with the rule and report GHG equipment leaks and vented GHG emissions. EPA used available industry and EPA data to characterize conditions at affected sources (i.e., affected facilities). Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility, and the associated costs were estimated for Subpart W. Table 4-1 presents the reporting and verification requirements for petroleum and natural gas systems.

Table 4-1 Selected Reporting Thresholds and Reporting Requirements

Subpart (Source Category)	Industry Segment	Reporting and Verification
W—Petroleum & Natural Gas Systems (§98.230)	(1) Onshore production (2) Offshore production (3) Natural gas processing (4) Natural gas transmission compression station (5) Natural gas underground storage (6) LNG storage (7) LNG import and export terminals (8) Natural gas distribution	(a) Report annual emissions separately for each of the industry segment listed in (a)(1) through (8) below. For each segment, report emissions from each source type in the aggregate, unless specified otherwise. For example, an underground natural gas storage facility with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number. (1) Onshore petroleum and natural gas production facilities. (2) Offshore petroleum and natural gas production facilities. (3) Onshore natural gas processing facilities. (4) Onshore natural gas transmission compression facilities. (5) Underground natural gas storage facilities. (6) Liquefied natural gas storage facilities. (7) Liquefied natural gas import and export facilities. (8) Natural gas distribution facilities. Report each source in the aggregate for pipelines and for metering and regulating (M&R) stations. (b) Emissions reported separately for standby equipment; (c) Report activity data for each aggregated source type as follows: (1) Count of emission sources. (2) Type of emission sources. (3) Number of specified events per year or reporting period (such as blowdowns, well completions, etc.). (4) Control measures and other equipment. (5) Volume and flow rates. (6) Input parameters for simulation software, if required. (7) Flared/vented/and equipment leak data. (d) Minimum, maximum and average throughput for each operation listed in industry segments (a)(1) through (8) above. (e) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both. (f) Report emissions separately for portable equipment for the following source types: drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters. (1) Aggregate emissions by source type. (2) Report count of each source type.

Note: Many facilities that would be affected by the rule emit GHGs from multiple sources. Each facility must assess every source category that could potentially apply to each when determining if a threshold has been exceeded. If the threshold is exceeded for any source category, the facility must report emissions from all source categories, including those source categories that do not exceed the applicable threshold.

4.2 Overview of Cost Analysis

The costs of complying with the rule will vary from one facility to another, depending on the types of emissions; the number of affected sources at the facility; existing monitoring, recordkeeping, and reporting activities at the facility; and other factors. The costs include labor and capital costs for performing the monitoring, recordkeeping, and reporting activities necessary to comply with Subpart W. All costs referred to in the EIA are in 2006 dollars.

There are two major emission categories for which costs are determined. One is the cost to quantify process emissions (i.e., equipment leaks and vented emissions); the other is the cost to quantify the additional combustion-related emissions for facilities that did not exceed the Subpart C threshold with only combustion emissions. The total burden estimates presented for Subpart W are comprised of the costs for process and combustion emissions, above those covered by Subpart C alone.

EPA first provides a general overview of baseline reporting and the two cost components associated with this information collection: 1) labor costs (i.e., the cost of labor by facility staff to meet the information collection requirements of the rule), and 2) 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). Additional details of the data, methods, and assumptions underlying the costs are documented in this section.

4.2.1 Baseline Reporting

In general, the Subpart W analysis assumes that none of the facilities in the covered segments are currently reporting equipment leaks and vented emissions and that many of the requirements will result in "new" or "full" costs to meet reporting requirements. Specifically, EPA assumes that there will be additional costs for any detection, sampling, and testing requirements in the methods used to quantify emissions from petroleum and natural gas sources. EPA also assumes that additional costs will be incurred for preparing monitoring and quality assurance/quality control (QA/QC) plans, performing the calculations, reporting the results, and maintaining records. The only significant element that EPA knows reporters subject to Subpart W already gather is the measurements and records of consumption of raw materials, such as feedstocks, as part of their routine operation for accounting purposes.

4.2.2 Reporting Costs

Costs for Subpart W were developed based on assessments of all estimated capital and operations and maintenance (O&M) costs to monitor, measure, detect and calculate the emission sources in all segments of Subpart W. Key variables and data fields were clearly defined to ensure that each segment developed costs around a standard set of methods and assumptions for Subpart W (e.g., method for annualization of capital costs, interest rate to be applied to capital). Cost estimates were developed for each threshold of emissions, based on the number of reporting entities in that threshold group and estimates of the specific capital and labor costs associated with conducting the emission reporting.

4.2.2.1 Labor Costs

The costs of complying with and administering this rule include the time of managers, technical, and administrative staff in the private and public segments. Staff hours are estimated for activities such as:

- Monitoring (private): staff hours to operate and maintain emission monitoring systems.
- Reporting (private): staff hours to gather and process available data and reporting it to EPA through electronic systems.
- Assuring and releasing data (public): staff hours to quality-assure, analyze, and release reports.

Staff activities and associated labor costs may vary over time. Thus, cost estimates are developed for start-up, first-time reporting, and subsequent reporting.

Loaded hourly labor rates (also referred to as “wage rates”) were developed for several labor categories to represent *the employer costs to use an hour of employees’ time* in each of the manufacturing segment labor categories used in this analysis. The labor categories correspond to the job responsibilities of the personnel that are likely to be involved in GHG emission monitoring activities at a petroleum or natural gas facility to comply with the rulemaking.

For purposes of this study, EPA adopted the methodology used by Rice (2002) to calculate the wage rates for the EPA’s TRI program. Thus, the *wage rates* calculated for different labor categories included the *employer costs for employee compensation* (comprising the basic wages and the corresponding benefits) and *the overhead costs to the employer*[18].

For each labor category applicable to Subpart W, the following formula was used to calculate the wage rates:

[18] For each employee, the employer also incurs *overhead costs* (comprising the rental costs of the office space, computer hardware and software, telecommunication and other equipments, organizational support, etc.) required for and used by the employee to effectively fulfill his/her job responsibilities. These costs are over and above the employee compensation costs.

$$\text{Loaded Hourly Labor Rate (\$/hr.)} = \text{Basic Wages (\$/hr.)} * (1 + \text{Benefits Loading Factor} + \text{Overhead Loading Factor})$$

The *benefits loading factor* corresponds to the relative share of benefits compensation in the total employee compensation (comprising basic wages and benefits). Although the benefits factor tends to vary by labor category and by industry (0.37 to 0.50), for purposes of this analysis, EPA has assumed the benefits loading factor to remain the same for each labor category across all industries in the rule due to a lack of availability of necessary industry-specific data on benefits paid to employees.

The *overhead loading factor* corresponds to the share of overhead costs to the employer relative to the total employee compensation. For the purposes of this analysis, EPA has also adopted the same overhead loading factor that Rice (2002) used in her wage rate calculations. Thus the overhead loading factor that EPA used in the wage rate calculations remains the same for all labor categories and across all industry types in the rule. The overhead loading factor was assumed to be 0.17.

For Subpart W, the combined “Benefits and Overhead Loading Factor” used is 0.67, or an overall adjustment of 1.67 times “Basic Wages.”

4.2.2.2 Capital and O&M Cost

This includes the cost of purchasing and installing monitoring equipment or contractor costs associated with providing the required information. Equipment costs include both the initial purchase price of monitoring equipment and any facility/process modification that may be required. Based on expert judgment, the engineering costs analyses annualized capital equipment costs with the appropriate lifetime and interest rate assumptions. The equipment life was set at five years for Subpart W sources with one-time capital costs amortized at a rate of 7 percent.

4.2.2.3 Other Recordkeeping and Reporting

Additional recordkeeping and reporting costs are added to Subpart W sources based on each segment’s estimated requirements. These costs are included in the “process emissions” total estimated costs.

4.3 Subpart W—Petroleum and Natural Gas Systems

4.3.1 Overview

The relevant reporters covered in this section are those for offshore petroleum and natural gas production, onshore petroleum and natural gas production (including enhanced oil recovery, EOR), onshore natural gas processing, onshore natural gas transmission compression, onshore natural gas storage, LNG storage, LNG import and export and natural gas distribution.

For each of the industry segments, with the exception of onshore production, operations had to be divided into single units or model facilities at three levels: small, medium, and large. The monitoring costs were then developed per size level of a model facility. A model facility of a given level can be defined as the most convenient and logical unit with appropriate emission source counts that can aggregate to any size company to determine its monitoring costs. For example, in natural gas transmission, a compressor station as a facility was modeled at the three different model size levels. Any natural gas transmission company can determine its monitoring costs by assigning the model facility costs to its facilities that are closest to the appropriate level of the model facility. To determine the national cost from each segment, EPA assigned a model facility cost that best fit the facility based on its emission profile. Next, EPA summed the costs assigned to each facility in the segment to produce the total national cost in each segment. Section 4.5 of this document describes the calculation in further detail.

Facilities in onshore production, however, are defined as “all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin,” as defined by the American Association of Petroleum Geologists. There is much larger variation in facility equipment by this definition, so developing model “small,” “medium,” and “large” facilities for monitoring costs is unintuitive and impractical. In this case, non-monitoring costs were estimated using the model facilities, but equipment monitoring costs were estimated at the national level and then apportioned to individual operators in basins by production rates.

Table 4-2 provides a summary of the number of facilities that would have to report under the various thresholds analyzed for each of the industry segments covered by the rule.

Table 4-2 Number of Facilities Reporting by Threshold and Industry Segment

Industry Segment	Threshold			
	1,000	**10,000**	**25,000**	**100,000**
Onshore Production	8,169	1,929	981	385
Natural Gas Processing	566	396	289	130

Industry Segment	Threshold			
	1,000	**10,000**	**25,000**	**100,000**
Transmission Compressor Stations	1,695	1,443	1,145	433
Natural Gas Storage	347	200	133	36
LNG Storage	54	41	33	4
LNG Terminals	5	4	4	4
Offshore Production	1192	184	58	4
Local Distribution Companies	594	203	143	66

4.3.2 Labor Costs

To evaluate labor costs, it was necessary not only to determine the amount of time required for all of the tasks associated with monitoring, but also to determine who will perform each task. For the sake of this analysis, four labor categories were used. Assigning labor hours for all cost elements was based on expert judgment. When assigning hours, the size of the facility and role of the labor categories were taken into consideration.

To estimate labor costs, it was assumed that all labor will be performed by middle managers, junior engineers, and senior operators. Middle managers are assumed to spend a total of two hours overseeing the monitoring process per quarter but are assumed not to perform any of the monitoring. It was assumed that junior engineers and contracted technicians will do all of the monitoring, except in cases where senior operators will log any activity data required to estimate emissions over the course of the quarter. Several equipment types are common between different onshore segments and different facility sizes, but the actual monitoring time typically will not change per equipment unit. For example, centrifugal compressor seals are found in all onshore segments, except for natural gas distribution and onshore production. Measuring centrifugal compressor seal degassing vents was assumed to take one hour and that will not change by segment or facility size. What changes is the number of centrifugal compressors located at facilities of different sizes. Thus, a series of universal assumptions about onshore monitoring times were created. These were multiplied by the emission source counts assigned to each of the model facilities to determine the required labor hours. Once the labor hours were calculated, by category, for each of the cost elements, they were multiplied by the associated labor rates to estimate labor costs per facility. For offshore monitoring, costs were developed on a per-platform basis for non-GOADS reporters, based on expert judgment. The only remaining facility costs are due to the annualized capital costs and travel, lodging, and shipping to conduct the actual emission monitoring.

Error! Reference source not found. Table 4-3 presents labor cost numbers aggregated across all segments for Subpart W. These data are aggregated from individual tables for each segment. Except for onshore production, each segment has a table for small, medium, and large facilities.

Table 4-3 Subpart W Petroleum and Natural Gas Systems: Labor Costs[a] (2006$)

	Estimated Labor Hours and Annual Labor Rates								Labor Cost per Year per Reporting Unit/Facility	
	Senior Management ($101.31/hr)		Middle Management ($88.79/hr)		Junior Engineer/ or Technician ($71.03/hr)		Senior Operator ($63.89/hr)			
Activity	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**	**First Year**	**Subseq. Year**
Planning	0.63	0.06	2.85	0.17	46.21	0.58	3.49	0.28	3,821	80
QA/QC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0
Recordkeeping	0.15	0.15	0.24	0.23	2.74	2.60	0.52	0.52	264	253
Sampling and analysis (calculations)	0.00	0.00	1.86	1.86	91.93	6.45	1.05	0.91	6,762	682
Reporting	0.05	0.04	1.24	1.08	4.13	3.73	13.81	13.10	1,291	1,202
Total	**0.83**	**0.25**	**6.19**	**3.35**	**145.01**	**13.36**	**18.87**	**14.80**	**12,139**	**2,217**

[a] Estimated onshore production average labor costs per year per reporting unit/facility are $12,099 for the first year and $5,168 for the subsequent years.

Unlike the other segments, onshore production labor costs were estimated by scaling up equipment-level labor hours, displayed later in this document in Table 4-13, to a national scale and then apportioning them by individual operator production rates. This approach was chosen over categorizing the operators by small, medium, and large because of the variety of operations present between operators in the onshore production segment. For this reason, the labor costs are not shown for the onshore production segment like in Table 4-3 or Table 4-4**Error! Reference source not found.**. The average operational and maintenance costs for the onshore production segment are shown below each table, however.

4.3.3 Capital and O&M Costs

The capital costs related to monitoring emissions and archiving information consist of purchasing equipment for emission detection (or the portion of contractor purchases of equipment is apportioned to all its customers), emission measurement, and information storage. All costs are reported in 2006 U.S. dollars and annualization was assumed over an equipment life of five years with a 7-percent interest rate. Equipment leak monitoring does not have time-tested standards and equipment leak streams typically are not clean gas. For example, a centrifugal compressor wet seal degassing vent will contain fine droplets of seal petroleum with the gas. A five-year equipment life was chosen to be conservative in cost estimates, as opposed to the 10-year equipment life associated with long-standing, proven practices of measuring clean fuel streams assumed in the stationary combustion section.

Error! Reference source not found. Table 4-4 shows the capital and operation and maintenance costs at the 25,000-metric-ton threshold for the aggregated Subpart W segments, less onshore production. The disparity in first-year capital costs stems from the fact that each of the onshore segments that use compressors as part of normal operations are required to pay for a one-time flow measurement port installation on compressor seal degassing vents and reciprocating rod packing vents. This approach assumes that there will be no disruption in the operations because the port can be installed when the compressor is either in standby mode or under maintenance. No adjustment is made, therefore, for production or operational loss. First-year labor costs include the labor required for registration, monitoring plan creation, and general planning procedures that are required only in the first year of compliance. The subsequent-year cost is a truer reflection of actual average costs over time.

Table 4-4 Subpart W Petroleum and Natural Gas Systems: Capital and O&M Costs[a] (2006$)

	Cost Categories				Capital and O&M Cost per Unit/Facility	
Activity	**Capital Cost**	**Equipment Lifetime (years)**	**Annualized Capital Cost (per year)**	**O&M Costs (per year)**	**First Year**	**Subseq. Year**
Equipment (selection, purchase, installation)	$1,676	6	$409	n/a	$409	$409
Performance testing[b]	n/a	n/a	n/a	n/a	n/a	n/a
Recordkeeping	$78	5	$19	n/a	$19	$19
Travel	N/A	n/a	n/a	$848	$848	$848
Total	$1,754	n/a	$428	$848	$1,276	$1,276

[a] Estimated onshore production average capital and O&M costs per unit/facility are $57 for the first year and $57 for the subsequent years.
[b] Performance testing is not required under Subpart W, and therefore no costs are entered.

4.3.4 Combustion Costs

Combustion emissions occur in petroleum and natural gas systems primarily through natural gas used to drive compressor engines. Additional fuel is used to power drilling rigs (diesel) and for process heaters and boilers, glycol dehydrators, and some acid gas removal reboilers. Combustion emissions are included for the purposes of determining if Subpart W thresholds are met; however, combustion emissions are reported separately under Subpart C for all industry segments, except onshore production and LDCs. Onshore production and LDC combustion emissions will be reported under Subpart W.

To estimate combustion emissions from compressor engines—the primary combustion application in Subpart W—only one emission factor was required per facility because the natural gas used for combustion is taken from one pipe of common fuel quality. Consequently the cost for monitoring fuel quality is relatively low even if there are multiple compressors at the facility.

This analysis includes the cost of incremental combustion reporting and combustion emissions above those that exceed the Subpart C threshold alone and would therefore already be have been reported under Subpart C. For purposes of cost estimation, EPA determined that under the final rule for Subpart W, entities that need to report incremental combustion-related emissions would use either the Tier 1 calculation methodology as set forth in Subpart C or the calculation methodology as set forth in Subpart W (40 CFR 98.233(z)). EPA determined that the entities reporting incremental emissions under subpart C would likely not meet the requirements for Tier 2 or higher methods. However, as these entities will be reporting combustion emissions under subpart C (except onshore production and LDCs), if a facility did meet the requirements for a tier other than Tier 1, the facility would have to use the required method, as specified in subpart C.

Given that the combustion methodology in 40 CFR 98.233(z) is similar to the Tier 1 calculation methodology, EPA estimated the costs to monitor and report incremental combustion-related emissions based on the approach used under 40 CFR part 98, subpart C. [19] Specifically, EPA applied the Tier 1 calculation methodology to estimate the costs to monitor combustion emissions that became subject to reporting as a result of today's final rule. Table 4-5 presents incremental combustion cost estimates. The Tier 1 approach bases estimates on a fuel-

[19] 40 CFR Part 98 used the IPCC tier concept to estimate combustions emissions (74 FR 56260, October 30, 2009). See EPA-HQ-OAR-2008-0508-0004, U.S. EPA, Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases, January 30, 2009, for more information about the IPCC tier methodology (pgs 10-15).

specific default CO_2 emission factor, a default high heating value of the fuel, and the annual fuel consumption from company records.

EPA based its conclusion that entities would likely report incremental combustion emissions using the Tier 1 method on three considerations for applicability of the Tier 2 calculation methodology and higher, as specified in Subpart C, to the petroleum and natural gas industry: 1) availability of high heating values (HHVs) for the fuels combusted at the frequency required by the Tier 2 calculation methodology, 2) the maximum-rated heat input capacity of the equipment, and 3) the type of fuel being combusted. First, in order to be allowed to use a Tier 2 analysis, units must have a rated heat-input capacity less than or equal to 250 million British thermal units per hour (MMBtu/hr), combust a fuel found in Table C-1 of subpart C, and sample the HHV of the fuel consumed at the required frequency in 40 CFR 98.34(a). It was determined that this minimum-required sampling frequency is not currently carried out at these smaller units, and therefore these units would not be required to use Tier 2. These units will generally follow Tier 1 methodology.

Second, Tier 3 and Tier 4 calculation methodologies generally apply to equipment with a maximum-rated heat-input capacity greater than 250 MMBtu/hr. A 250-MMBtu/hr rating means that the emissions from that individual unit alone will be greater than 25,000 MtCO2e; these emissions would be subject to reporting under Subpart C even in the absence of Subpart W and therefore would not fall in the category of incremental combustion emissions considered in this analysis.

Third, the predominant fuels used in the petroleum and natural gas industry are produced natural gas, pipeline quality natural gas, distillate fuel, and any products recovered from equipment leaks and vents. The use of produced natural gas is predominant in onshore petroleum and natural gas production. Under the final rule for subpart W, reporters in this segment are allowed to use methods similar to Tier 1 for all combustion emissions sources that use produced natural gas.

In the remaining segments, equipment using produced natural gas or products recovered from equipment leaks and vents are normally required to use Tier 2 methodology or higher. However, as described previously, if the unit has a rated heat input less than or equal to 250 MMBtu/hr, then the unit probably does not currently receive HHV at the required frequency for a Tier 2 and could use a Tier 1 analysis instead. If the unit has a maximum-rated heat-input capacity greater than 250 MMBtu/hr, then as just noted, emissions from a unit of this size would already be subject to reporting and would not be included in the incremental combustion emission category considered in this analysis. In sum, the use of Tier 1 methodology for incremental combustion is a reasonable assumption for costing the subpart W rule.

Table 4-5 Subpart W Petroleum and Natural Gas Systems: Combustion Costs (2006$)

Activity	Cost Categories				Total Reporting Cost per Unit/Facility	
	Capital Cost	Equipment Lifetime (years)	Annualized Capital Cost (per year)	O&M Costs (per year)	First Year	Subseq. Year
Equipment (selection, purchase, installation)	$3,500	10	$500	$1,700	$2,200	$2,200
Total	**$3,500**		**$500**	**$1,700**	**$2,200**	**$2,200**

4.4 Summary Results: Subpart W—Petroleum and Natural Gas Systems

For each segment in the petroleum and natural gas industry identified as amenable to a reporting program, four thresholds were considered for emission reporting as applicable to an individual facility: 1,000 $MtCO_2e$ per year; 10,000 $MtCO_2e$ per year; 25,000 $MtCO_2e$ per year; and 100,000 $MtCO_2e$ per year. A threshold analysis was then conducted on each segment to determine which level of threshold was most suitable for each industry segment. CH_4, CO_2, and N_2O emissions from each segment were included in the threshold analysis.

Table 4-6 shows the number and share of entities and emissions covered by the final rule. The table shows that at lower thresholds, a higher number and share of facilities and emissions are covered by the rule. As the threshold increases, smaller numbers and shares of facilities and emissions are affected. Of significant note, 85 percent of emissions are covered at the selected 25,000-$MtCO_2e$ threshold, but only 9 percent of facilities need to report. Furthermore, both total emissions and covered emissions include incremental combustion emissions (i.e. those not triggered by the threshold of Subpart C alone).

Table 4-6 Subpart W Facilities and Emissions Covered by Final Rule

Threshold	Number of Entities	Number of Facilities Covered	Percent of Facilities Covered	Total Emissions (Million $MtCO_2e$/Year)	Covered Emissions (Million $MtCO_2e$/ Year)	Percent of Emissions Covered
1,000 $MtCO_2e$/yr Threshold	30,241	12,622	42%	396	391	99%

10,000 $MtCO_2e/yr$ Threshold	30,241	4,400	15%	396	362	91%
25,000 $MtCO_2e/yr$ Threshold	30,241	2,786	9%	396	337	85%
100,000 $MtCO_2e/yr$ Threshold	30,241	1,062	4%	396	273	69%

4.4.1 Detailed Threshold Analysis

For each segment, a threshold analysis was conducted to determine how many of the facilities in the segment exceed the various reporting thresholds, and the total emissions from these facilities. This analysis was conducted considering vented and equipment leaked CH_4 and CO_2 emissions, and combustion CH_4, CO_2, and N_2O emissions. The vented emission and equipment leak estimates available from the U.S. GHG Inventory were used in the analysis. The emission estimates for four sources—well venting for liquids unloading, gas well venting during well completions, gas well venting during well workovers, and centrifugal compressor wet seal degassing venting—from the U.S. GHG Inventory were replaced with revised estimates, however, which are described in Appendix B of the TSD.

Combustion emissions from processing, transmission, underground storage, LNG storage, and LNG import and export terminals were estimated using gas engine methane emission factors available from GRI/EPA (1996), back-calculating the natural gas consumption in engines, and finally applying a CO_2 emission factor to the natural gas consumed as fuel. N_2O emissions were calculated similarly. In the case of offshore petroleum and natural gas production platforms, combustion emissions are already available from the GOADS (2000) study analysis and hence were directly used for the threshold analysis. In addition to gas engines, combustion emissions from reboilers on glycol dehydrators, acid gas removal amine regeneration, diesel engines on drilling rigs, and heater-treaters were estimated for onshore production. The volume of fuel gas required by regular operation of a glycol dehydrator was calculated per volume of dehydrator input; then the API Compendium combustion emission factors for natural gas were applied to facilities' fuel gas use based on their gas production rates. The same assumptions were made to calculate combustion emissions from acid gas removal amine regeneration heaters. Drilling rigs were assumed to operate two 1,500-horsepower diesel engines per well drilled, and assuming it requires 90 days to drill and complete any well. The API Compendium combustion emission factors for diesel engines were used to calculate the emissions. The total drilling emissions for the nation were calculated based on the number of drilling rigs in service, then apportioned to each basin by throughput.

The threshold analysis for the rule includes equipment leak, vented, and combustion emissions and requires estimation of all emissions at a facility level. As a result, the total emissions from the threshold analysis do not necessarily match the U.S. GHG Inventory for all segments of the petroleum and natural gas industry. A detailed discussion on the threshold analysis is available in the TSD (EPA-HQ-OAR-2009-0923).

The general rationale for selecting a reporting threshold is to identify a level at which the incremental emission reporting between thresholds is the highest for the lowest incremental increase in number of facilities reporting between the same thresholds. This approach would ensure maximum emission reporting coverage with minimal burden on the industry.

Table 4-7 summarizes the national costs and costs per representative entity for each threshold. The first five columns report subsets of costs, including costs associated with processes (labor, annualized capital, and operating and maintenance costs), costs associated with stationary combustion, and costs associated with reporting and recordkeeping. The final four columns report total national costs and total per-entity costs for the first year and for subsequent years.

Table 4-7 Summary of National Costs and Costs per Representative Entity by Threshold (Million 2006$)[a]

Threshold ($MtCO_2e/yr$)	First-Year Process Costs[b]	Subseq.-Year Process Costs[a]	First-Year Combustion Costs	Subseq.-Year Combustion Costs	First-Year National Costs	First-Year Representative Entity Cost	Subseq.-Year National Costs	Subseq.-Year Representative Entity Cost
1,000	$112.3	$46.4	$23.9	$23.9	$136.2	$0.011	$70.3	$0.006
10,000	$53.0	$20.9	$6.6	$6.6	$59.6	$0.014	$27.5	$0.006
25,000	$40.1	$15.1	$3.3	$3.3	$43.4	$0.016	$18.4	$0.007
100,000	$23.1	$7.7	$0.9	$0.9	$24.0	$0.023	$8.6	$0.008

[a] Excludes determination costs for non-reporters; see next section for estimates of these costs.
[b] Reporting and recordkeeping costs are included in process costs.

Note that first-year costs are significantly higher than the subsequent-year average costs, due to the following reasons:

- Initial start-up costs include labor and capital associated with establishing modifications to enable ongoing quantification of key emission sources. They include costs to install measurement ports in compressor and well vents.

- For onshore production, reporting occurs annually, but the measurement of key sources is updated every two years.

4.4.2 Subsequent-year costs are therefore reported as an average of the cost for years two, three, and four. As described in Table 4-7, at lower thresholds, a larger number of facilities in each subpart are covered by the rule and thus incur costs. For this reason, the total national costs, and total costs by cost subset, decline as the threshold increases from 1,000 $MtCO_2e$ to 10,000 $MtCO_2e$, to 25,000 $MtCO_2e$, and finally to 100,000 $MtCO_2e$. Cost per representative entity for a particular segment generally declines for Subpart W as the threshold increases. Reporting Determination

While the cost estimates for representative entities are assumed to capture the reporting determination burden (i.e., the burden of estimating emissions to determine whether they exceed the reporting threshold), they do not account for the reporting determinations made by facilities that fall below the threshold. EPA has therefore estimated the burden for reporting determinations made by these facilities in order to better reflect the rule's total economic burden.

EPA plans to develop screening tools and has assumed that most facilities will use them to make a reporting determination. As a first step, facilities would enter basic activity data, such as number of compressors and compressor cylinders, into the tool to roughly assess whether they exceed the threshold. The screening results should allow many facilities to make their threshold determination. Some of the facilities may have to take steps in addition to the screening tools, however, to determine if they have to report. For example, facilities that estimate emissions close to the reporting threshold may want to conduct preliminary monitoring to better determine their emissions. Such facilities may also conduct preliminary monitoring in subsequent years to determine whether emissions in those years meet or exceed the reporting threshold.

Of the 30,241 facilities in the petroleum and natural gas industry, approximately 2,786 facilities would likely meet the threshold and have to report. The remaining 27,455 facilities are expected to be below the reporting threshold and would likely use the screening tool to make this reporting determination. In addition, 296 of the 27,455 facilities could have emissions close to the threshold and may supplement the screening tool analysis with some preliminary monitoring to determine whether or not they need to report; these 296 facilities are also assumed to conduct preliminary monitoring to make a reporting determination in subsequent years.

Facilities are required to follow methodologies in the rule to make a determination. The costs for this activity are outlined as follows:

Planning costs are assumed to include:

- 2.5 hours for regulatory review
- 2 hours to understand what operations information is required

- 2 hours to gather operations data for screening tool(s)
- 14 hours to conduct preliminary monitoring

Recordkeeping and reporting costs are assumed to include:

- 1 hour to use screening tool(s) and to review and report data

Using the labor costs presented in Section 4.5.1, the cost of the reporting determination would be $573 per facility. The additional cost for those entities close to, but not exceeding, the threshold, to conduct preliminary monitoring, is $1,034. See the memo, *Estimates of Determination Costs*, in the docket for complete details about these calculations (EPA-HQ-OAR-2009-0923). Table 4-8 provides a summary of the determination costs by industry segment and threshold level.

Table 4-8 Summary of Reporting Determination Costs per Segment by Threshold (2006$ in thousands)[a]

Segment	Year	Thresholds (metric tons) 1,000	10,000	25,000	100,000
Onshore petroleum and natural gas production	First Year	$9,146	$12,177	$12,496	$12,731
	Subsequent year	$1,448	$604	$256	$92
Offshore petroleum and natural gas production	First Year	$1,921	$2,886	$2,972	$2,996
	Subsequent year	$241	$110	$33	$3
Natural gas transmission	First Year	$259	$572	$903	$1,167
	Subsequent year	$9	$114	$165	$6
Natural gas processing	First Year	$0	$223	$310	$392
	Subsequent year	$0	$94	$52	$6
Natural gas underground storage	First Year	$56	$232	$292	$379
	Subsequent year	$9	$58	$43	$19
LNG storage	First Year	$4	$17	$26	$55
	Subsequent year	$2	$2	$2	$2
LNG import & export terminals	First Year	$13	$55	$68	$140
	Subsequent year	$0	$0	$0	$0
Natural gas distribution	First Year	$921	$1,276	$1,330	$1,406
	Subsequent year	$133	$47	$32	$28
Total	**First Year**	$12,320	$17,438	$18,396	$19,267
	Subsequent year	$1,841	$1,030	$582	$156

[a] These estimates are conservative and should be viewed as an upper-bound because they were calculated at the facility-level rather than the company-level. For example, for offshore production, determination costs were applied to each of the approximately 3,000 platforms in the Gulf of Mexico rather than to the roughly 86 operators in that region. See the memo, "Estimates of Determination Costs," in the docket for complete details and additional determination cost estimates (EPA-HQ-OAR-2009-0923).

4.5 Detailed Cost Assumptions: Subpart W—Petroleum and Natural Gas Systems

The cost assumptions are the basis for the determination of the costs noted in this section.

STEP 1: Model Facility Development

For each of the industry segments, with the exception of onshore production, operations had to be divided into single units or model facilities at three levels: small, medium, and large. The monitoring costs were then developed per size level of a model facility. A model facility of a given level can be defined as the most convenient and logical unit with appropriate emission source counts that can aggregate to any size company to determine its monitoring costs. For example, in onshore natural gas transmission, a compressor station as a facility was modeled at the different levels. Any transmission company can determine its monitoring costs by assigning model facility costs to its facilities that are closest to the appropriate level of the model facility. Facilities in onshore production, however, are defined as operators reporting all equipment covered at the basin-level. There is much larger variation in facilities' equipment by this definition, so developing model "small," "medium," and "large" facilities is unintuitive and impractical for estimating monitoring costs. In this case, non-monitoring costs were estimated using the model-facility method and monitoring costs were estimated at the national level and then apportioned to individual operators in basins by production rates.

For each of the sources designated for monitoring, both equipment and component counts were determined to define individual model facilities, except as noted in onshore production. For onshore natural gas processing, onshore natural gas transmission, underground natural gas storage, LNG storage, import and export facilities and natural gas distribution, equipment and component counts for medium facilities were assigned the national average activity factors from the national inventory, or the nearest reasonable integer value. In some cases, the uncertainty associated with the activity factors were used to determine the lower bound on equipment and component counts, and assigned to a "small" facility. Similarly, the upper bound on emission source counts was assigned to a "large" facility. If illogical values, such as in the case of compressors in natural gas transmission compressor stations, resulted from the above methodology; expert judgment was used to correct the values; bounding the aggregated activity levels to that of the national inventory. In the case of offshore petroleum and natural gas production, BOEMRE GOADS (2000) data analysis by EPA was used in the same fashion as the national inventories. In some cases, the uncertainty estimates were not applicable. For example, if the uncertainty is greater than 100 percent, it would predict a negative lower bound for emission source counts. For these cases, expert judgment was used. Expert judgment was also used, where necessary, to adjust emission source counts to reflect real-world scenarios. Both equipment and component counts at facilities by segment and size are presented in the docket (EPA-HQ-OAR-2009-0923).

STEP 2: Determine Cost Elements

The total costs associated with complying with the April 2009 proposed rulemaking were broken into five elements, each of which is described in the following information. Additionally, these cost elements are considered in two ways: costs associated with start-up, and recurring costs. Startup costs refer to a one-time cost associated with initiating the reporting process. Subsequent costs for reporting on an annual basis are less than the startup costs and are referred to as recurring costs.

1. Regulation compliance determination costs

    a. Start-up costs consist entirely of the labor necessary to study and review the regulations to assure compliance, gather data on the facility, and fill out any appropriate forms.

    b. Recurring costs will be small and consist entirely of labor expenses. Small amounts of time will be required for the company to stay aware of any updates to regulations and to alter the facility information to reflect any new equipment or facilities brought into operation or taken offline.

2. Monitoring costs

    a. Start-up monitoring costs consist of both labor and capital costs. Capital investment will be required for purchasing monitoring equipment. This capital cost will be accounted as annualized cost, on an annual basis. Labor will be required for product research for monitoring instruments before actual purchase. Before actual monitoring takes place, labor will have to be devoted to the development of a monitoring plan that will be used company-wide. Finally, selected employees will be trained on how to use the monitoring equipment.

    b. Recurring monitoring costs consist of labor, travel, and shipping of equipment. During each cycle, labor will be required to conduct detection and quantification of emissions (i.e., perform actual monitoring of emissions). Quantification may take place through direct measurement, use of engineering calculations and/or software, use of "leaker" emission factors for detected leaks, or use of component counts and population emission factors. For companies with multiple facilities, travel may be required for the monitoring team and/or the monitoring instruments may require shipping to multiple locations.

3. Reporting costs

    a. There will be no start-up reporting costs; reporting costs are applied uniformly across segments reporting to the rule.

    b. Recurring reporting costs consist of labor necessary to document collected emission data from equipment leak monitoring and to submit the official report in each cycle (i.e., annually).

4. Archiving and recordkeeping costs

    a. Start-up archiving and recordkeeping costs consist of labor and annualized capital purchase of storage space. For archiving reports and associated working documents, a physical storage system such as a file cabinet and an electronic storage system such as an external hard drive will be required.

    b. Recurring archiving and recordkeeping costs consist entirely of labor necessary to adequately archive each cycle's report and associated working documents.

5. Auditing costs

    a. There is no start-up cost associated with auditing.

    b. Recurring auditing costs consist of labor required to validate the EPA results from emission monitoring and the follow-up from rectifying any weaknesses found through the audit. The EPA audit is assumed to occur once in several years, not on an annual basis.

STEP 3: Analyze Proportion of Facilities in Different Model Facility Levels

Facilities were classified and rank-listed in ascending order based on their sizes, total combustion, equipment leaked, and vented CO_2, N_2O, and CH_4 emissions, expressed in CO_2e. Cumulative emissions for the facilities were calculated by adding the emissions of an individual facility to those of the facilities before it in the ascending list. The cumulative emissions, in combination with the total emissions from all facilities, were used to assign facilities to the small, medium, and large category.

$$Percentile(\%) = \left(\frac{CumulativeEmissions}{TotalEmissions} \right)$$

The facilities that accounted for the first 33 percent of the emissions nationally in the ranked list were identified as small facilities. The facilities that accounted for national emissions greater than 33 percent but less than 67 percent in the ranked list were identified as medium facilities. The facilities that accounted for national emissions greater than 67 percent in the ranked list were identified as large facilities. Table 4-9 indicates the data sources used to apportion total GHG emissions to individual facilities, and the number of facilities that fall into each category per segment.

STEP 4: Assigning Costs to Cost Elements

Assigning costs to each of the cost elements was completed in three steps:

1. Determine labor categories and associated labor rates.
2. Allocate responsibilities to labor categories to estimate labor hours.
3. Determine annualized capital costs and O&M costs for each of the cost elements.

These steps are described in more detail as follows:

Table 4-9 Allocation of Facilities to Model Types

Segment	Data Source	Small Facilities	Medium Facilities	Large Facilities
Offshore Petroleum and Natural Gas Production				
Facility Percentile	BOEMRE, 2000 *GOADS Emission Inventory*, Lasser, 2006	0–33%	34%–67%	68%–100%
Facility Count	BOEMRE, 2000 *GOADS Emission Inventory*, Lasser, 2006	3,036	191	8
Mean Emissions ($MtCO_2e$)	This Analysis	1,430	22,733	483,806
Operator/Company [a]	Not estimated			
Onshore Petroleum and Natural Gas Production[b]				
Facility Percentile	HPDI, 2006	0–33%	34%–67%	68%–100%
Facility Count	HPDI, 2006	22,275	194	41
Operator/Company	HPDI, 2006	—	—	—
Mean Emissions ($MtCO_2e$)	This Analysis	3,988	451,120	2,170,820
Onshore Natural Gas Processing				
Facility Percentile	API, 2008 *Impact Assessment of Mandatory GHG Control Legislation*	0–33%	34%–67%	68%–100%
Facility Count [c]	API, 2008 *Impact*	486	64	16

Segment	Data Source	Small Facilities	Medium Facilities	Large Facilities
	Assessment of Mandatory GHG Control Legislation			
Operator/Company	API, 2008 *Impact Assessment of Mandatory GHG Control Legislation*	166	28	10
Mean Emissions (MtCO_2e)	This Analysis	36,486	275,823	1,137,595
Onshore Natural Gas Transmission				
Facility Percentile	FERC, 2008	0–33%	34%–67%	68%–100%
Facility Count	FERC, 2008	1,314	374	255
Operator/Company	FERC, 2008	147	46	27
Mean Emissions (MtCO_2e)	This Analysis	21,293	98,738	210,829
Natural Gas Underground Storage				
Facility Percentile	EIA, 2006. *Underground Storage Field Level Data*	0–33%	34%–67%	68%–100%
Facility Count	EIA, 2006. *Underground Storage Field Level Data*	325	50	22
Operator/Company	EIA, 2006.*Underground Storage Field Level Data*	102	37	17
Mean Emissions (MtCO_2e)	This Analysis	12,404	82,199	183,936
LNG Storage				
Facility Percentile	GTI. 2007. *The World Energy Source Book*	0–33%	34%–67%	68%–100%
Facility Count	GTI. 2007. *The World Energy Source Book*	141	12	4
Operator/Company	GTI. 2007. *The World Energy Source Book*	141	11	3
Mean Emissions (MtCO_2e)	This Analysis	20,972	55,340	223,275
LNG Import and Export				
Facility Percentile	FERC, 2008	—	0–100%	—
Facility Count	FERC, 2008	—	5	—
Operator/Company	Not estimated			
Mean Emissions (MtCO_2e)	This Analysis	—	174,643	—
Natural Gas Distribution				
Facility Percentile	DOT, 2006	0–33%	34%–67%	68%–100%
Facility Count	DOT, 2006	1,360	50	17
Operator/Company	DOT, 2006	1,268	49	16
Mean Emissions (MtCO_2e)	This Analysis	5,840	167,066	536,719

Notes:

[a] The BOEMRE 2000 *Gulfwide Emissions Inventory* reports 2,525 offshore platforms and 86 operators. No data are available for individual offshore platforms and their respective operators.

[b] The onshore production burden analysis was conducted using a hybrid approach. Capital costs and some recurring O&M costs were assigned on a small, medium, and large basis; however, the majority of the recurring O&M costs were determined by apportioning nationwide costs by individual operator throughput.

[c] Assumed one facility per company; no data available for small plants.

4.5.1 Determining Labor Categories

To evaluate labor costs, it was necessary to not only determine the amount of time required for all of the tasks associated with monitoring, but also to determine who will perform each task. For the sake of this analysis, five labor categories were used, as shown in Table 4-10.

Table 4-10 Labor Categories and Hourly Rates

Labor Category	Description	Loaded Hourly Rate[a]
Senior Manager	Oversees work at a high level. Is the final authority on all reporting requirements.	$101.31/hour
Middle Manager	Oversees junior engineer's progress and reports; also interacts with senior manager. Does not gather information, write reports, or perform monitoring.	$88.79/hour
Junior Engineer	Conducts monitoring of emission sources. Interfaces between middle manager and senior operator to collect information and complete reports.	$71.03/hour
Senior Operator	Primarily interfaces with junior engineer to collect facility information and assist with initiating the reporting process and reporting. Sometimes logs data used in the monitoring process.	$63.89/hour
Technician	Contracted by the company to perform basic leak detection activities.	$55.20/hour

[a] Source: U.S. Department of Labor, 2003.

These labor rates originate from an analysis of loaded hourly rates for goods and producing private establishments at the end of 2007, shown in Table 4-11. Since the petroleum and natural gas industry hourly rates are high compared to other industries, the top four non-lawyer categories were used to be conservative in this approximation. Specifically, the labor rate of senior managers were assumed to be that of refinery mangers; middle manager labor rates were assumed to be that of electricity managers; junior engineer labor rates were assumed to be that of industrial managers; senior operator labor rates were assumed to be that of refinery engineers/technicians; and contracted technician labor rates were assumed to be that of industrial engineer/technician category.

Table 4-11 Loaded Hourly Rates for Goods-Producing Private Establishments

Labor Category	Loaded Hourly Rate ($/hour)[a]
Electricity Manager	$88.79
Refinery Manager	$101.31
Industrial Manager	$71.03
Lawyer	$101.00
Electricity Engineer/Technician	$60.84

Refinery Engineer/Technician	$63.89
Industrial Engineer/Technician	$55.20
Administrative Support	$29.65

[a] Source: U.S. Department of Labor, Bureau of Labor Statistics, National Compensation Survey - Compensation Cost Trends, Employer Cost for Employee Compensation (ECEC), Customized Tables, as of March 11, 2003.

4.5.2 Allocating Responsibilities

Assigning labor hours for all cost elements was based on expert judgment. When assigning hours, the size of the facility and role of the labor categories were taken into consideration. Table 4-12 summarizes these roles.

Table 4-12 Responsibilities for Regulation Compliance by Labor Category

Cost Element	Senior Management	Middle Management	Junior Engineer	Senior Operator	Per Facility/ Per Company[a]
Facility data	To review reporting documentation/ systems and facility data	To review reporting documentation/ systems and facility data	To initiate reporting process and prepare facility data	To prepare and review reporting process documentation and facility data	Per facility
Regulation review	To review the new regulations	To review the new regulations	To examine and identify potential new regulations	To review the new regulations identified and determine their applicability	Per company
Plan development	To review the monitoring plan	To review the monitoring plan	To develop a monitoring plan	To develop and review the monitoring plan	Per company
Equipment purchase	To approve the equipment purchase	To review the equipment to be purchased	To identify and purchase the equipment	To review the equipment to be purchased	Per company
Start-up/ training		To review training plan	To acquire training	To provide and acquire training	Per facility
Data documentation	To review the reporting documentation	To prepare and complete the reporting documentation	To prepare reporting documentation	To prepare and complete reporting documentation	Per facility
Report submission		To ensure the completion of the reporting documentation	To submit the report		Per Facility
Archiving reports			To archive the reporting documentation	To archive the reporting documentation	Per facility
Audit	To review the audit results	To review the audit results	To assist and provide information on EPA audits		Per facility

Cost Element	Senior Management	Middle Management	Junior Engineer	Senior Operator	Per Facility/ Per Company[a]
Audit follow-up	To review the audit follow-up results and approve corrective measures	To review the audit follow-up results and review corrective measures	To determine corrective measures from EPA audit	To assist in determining corrective measures from EPA audit	Per facility

[a] Some activities only have to be done at the company level, with information and/or equipment shared among facilities of the company.

The labor costs associated with performing the actual annual monitoring were omitted from Table 4-12. For these costs, it was assumed that all labor will be performed by middle managers, junior engineers, senior operators, and contracted technicians. The assumed responsibilities and associated hours are organized in Table 4-13.

Additionally, several pieces of equipment are common among different onshore segments and different facility sizes, but the actual monitoring time typically will not change per equipment unit. The series of universal assumptions about onshore monitoring times are also provided in Table 4-13.

Table 4-13 does not include equipment monitoring on offshore petroleum and natural gas production facilities. Offshore production platforms are proposed to use data already collected for BOEMRE GOADS to estimate GHG emissions from their operations. Specifically, the BOEMRE GOADS program requires GHG emission monitoring from platforms in the Gulf of Mexico federal waters. Facilities under this final rulemaking are required to report the same emission data calculated by the GOADS program; hence, these platforms have minimal additional reporting burden. The cost burden model assumes that this monitoring requires 30 minutes per platform.

Table 4-13 Responsibilities for Monitoring and Allocation of Labor Hours

Element	Onshore Responsibilities by Labor Category and Hours per Responsibility		
	Detection	Quantification	Applicable Segments
Onshore Facility Equipment Leaks			
Senior operator	Count large, major pieces of equipment (0.5 minutes/equipment)		Onshore Production
Processing Facility Equipment Leaks			
Technician	Conduct equipment leak detection survey (8 hours/small facility, 12 hours/medium facility, or 16		Processing

Element	Onshore Responsibilities by Labor Category and Hours per Responsibility		
	Detection	Quantification	Applicable Segments
	hours/large facility)		
Junior engineer		Estimate emissions using leaker factors (2 hours/facility)	Processing
Middle management	Oversee part of the detection process and review results (1 hour/reporting period)	Oversee part of the measurement process and review results (1 hour/reporting period)	Processing
Transmission Facility Equipment Leak			
Technician	Conduct equipment leak detection survey (17 hours/small facility, 19 hours/medium facility, and 19 hours/large facility)		Transmission
Junior engineer		Estimate emissions using leaker factors (2 hours/small facility, 2 hours/medium facility, and 3 hours/large facility)	Transmission
Middle management	Oversee part of the detection process and review results (1 hour/reporting period)	Oversee part of the measurement process and review results (1 hour/reporting period)	Transmission
Underground Storage Facility Equipment Leak			
Technician	Conduct equipment leak detection survey (47 hours/small facility, 53 hours/medium facility, and 63 hours/large facility)		Storage
Junior engineer		Estimate emissions using leaker factors (2 hours/small facility, 3 hours/medium facility, and 2 hours/ large facility)	Storage
Middle management	Oversee part of the detection process and review results (1 hour/reporting period)	Oversee part of the measurement process and review results (2 hours/reporting period)	Storage
LNG Import/Export Terminal Equipment Leak			
Technician	Conduct equipment leak detection survey (43 hours/facility)		LNG Import and Export Facilities
Junior engineer		Estimate emissions using leaker factors (2 hour/ facility)	LNG Import and Export Facilities
Middle management	Oversee part of the detection process and review results (2	Oversee part of the measurement process and	LNG Import and Export Facilities

Element	Onshore Responsibilities by Labor Category and Hours per Responsibility		
	Detection	Quantification	Applicable Segments
	hours/reporting period)	review results (1 hour/ reporting period)	
LNG Storage Facility Equipment Leak			
Technician	Conduct equipment leak detection survey (12 hours/small facility, 19 hours/medium facility, and 24 hours/large facility)		LNG Storage
Junior engineer		Estimate emissions using leaker factors (2 hours/small facility, 2 hours/medium facility, and 3 hours/large facility)	LNG Storage
Middle management	Oversee part of the detection process and review results (1 hour/reporting period)	Oversee part of the measurement process and review results (1 hour/reporting period)	LNG Storage
LDC Above Grade M&R Station Equipment Leak			
Technician	Conduct equipment leak detection survey (1 minute/station)		Distribution
Junior engineer		Estimate emissions using leaker factors (8 hours/reporting period)	Distribution
Middle management	Oversee part of the detection process and review results (2 hours/reporting period)	Oversee part of the measurement process and review results (1 hour/reporting period)	Distribution
Reciprocating Compressor Equipment Leak			
Technician	Check unit for equipment leaks (1 hour/compressor)		Processing
Technician	Check unit for equipment leaks (1.5 hours/compressor)		Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Junior engineer		Apply emission factors or leaker factors (time accounted for by facility equipment leaks quantification)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Reciprocating Compressor Rod Packing Emissions			
Maintenance team		One time labor cost to install port for hotwire anemometer ($1,000 /compressor)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Technician	Check packing open-ended lines for emissions (10 minutes/compressor)		Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Technician		Measure rod packing emissions (10	Processing, Transmission, Storage, LNG Storage, LNG

Element	Onshore Responsibilities by Labor Category and Hours per Responsibility		
	Detection	Quantification	Applicable Segments
		minutes/compressor)	Import and Export Facilities
Junior engineer		Calculate rod packing emissions (30 minutes/compressor)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Centrifugal Compressor Equipment Leaks			
Technician	Check unit for equipment leaks (1 hour/compressor)		Processing
Technician	Check unit for equipment leaks (2 hours/compressor)		Storage, LNG Import and Export Facilities
Technician	Check unit for equipment leaks (2.5 hours/compressor)		LNG Storage
Centrifugal Compressor Seals			
Maintenance team		One-time labor cost to install port for hotwire anemometer ($5,000/compressor)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Technician		Measure degassing vent emissions (10 minutes/compressor)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Junior engineer		Calculate degassing vent emissions (30 minutes/compressor)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Unconventional Well Completion and Workover			
Junior engineer		Measure flowback from completion or workover (8 hours/field)	Onshore Production
Conventional Well Completion and Workover			
Junior engineer		Ask completion or workover contractor for time of venting (5 minutes/per completion or workover)	Onshore Production
Well Liquid Unloading			
Junior engineer		Measure flow from well blowdown (5 minutes/unloaded well)	Onshore Production
Acid Gas Removal Vent Stacks			
Junior engineer		Perform simulation runs (10 minutes/AGR vent)	Processing
Kimray Pumps			
Junior engineer		Accounted for in station equipment leaks– certain portion of time is assumed to be for engineering estimation of sources	Onshore Production, Processing, Transmission, Storage
Dehydrator Vent Stacks > 400 thousand cubic feet			

Element	Onshore Responsibilities by Labor Category and Hours per Responsibility		
	Detection	Quantification	Applicable Segments
Senior operator		Collect data collection (10 minutes/dehydrator vent)	Onshore Production, Processing
Junior engineer		Perform simulation runs (15 minutes/dehydrator vent)	Onshore Production, Processing
Junior engineer		Accounted for in station equipment leaks – certain portion of time is assumed to be for engineering estimation of sources	Transmission, Storage
Dehydrator Vent Stacks <400 thousand cubic feet			
Senior operator		Count dehydrator (0.5 minutes/dehydrator vent)	Onshore Production, Processing
Wellhead Equipment Leaks			
Junior engineer		Apply emission factor – accounted for in station equipment leaks	Onshore Production, Storage
Storage Tanks > 10 barrels per day			
Senior operator		Collect separator pressure (1 minute/separator)	Onshore Production
Junior engineer		Collect data and perform simulation runs (30 minutes/ separator)	Onshore Production
Storage Tanks < 10 barrels per day			
Senior operator		Count separator (0.5 minutes/separator)	Onshore Production
Natural Gas Distribution Pipelines			
Junior engineer		Estimate emissions using population emission factor – time accounted for in station equipment leaks	Distribution
Below Grade Metering & Regulating Stations			
Junior engineer		Estimate emissions using population emission factor – time accounted for in station equipment leaks	Distribution
Well Testing			
Junior engineer		Perform emissions calculation with GOR measurement (1 hour/ well)	Onshore Production
Associated Gas Venting and Flaring			
Junior engineer		Perform emission calculation with gas-to-oil ration (GOR) measurement (1 hour/well)	Onshore Production
Natural Gas Pneumatic Bleed Devices			

Element	Onshore Responsibilities by Labor Category and Hours per Responsibility		
	Detection	**Quantification**	**Applicable Segments**
Junior engineer		Determine high bleed or low bleed from manufacturer and apply appropriate population factor (10 minutes/pneumatic device)	Onshore Production, Processing, LNG Storage, LNG Import and Export Facilities, Distribution
Junior engineer	Check devices and take inventory of brand/models (8 minute/pneumatic device)	Determine high bleed or low bleed from manufacturer and apply appropriate population factor (10 minutes/pneumatic device)	Transmission, Storage
Flare Stacks			
Junior engineer	Collect data for emission estimate (10 minutes/ station)	Estimate emissions using emission factor (10 minutes/ station)	Processing
Junior engineer		Apply emission factor – accounted for in station equipment leaks	Onshore production
Blowdown Vent Stacks			
Junior engineer		Perform emissions calculation (8 minutes/ station)	Processing, Transmission, Storage, LNG Storage, LNG Import and Export Facilities
Junior engineer		Accounted for in station equipment leaks	Distribution

For platforms that are in state waters or in federal waters outside the Gulf of Mexico, GHG emissions will have to be estimated using the BOEMRE GOADS procedures. EPA estimates the reporting cost for non-GOADS platforms to be $5,000 for first year of reporting.

Once the labor hours were calculated, by category, for each of the cost elements, they were multiplied by the associated labor rates to estimate labor costs per facility. The only remaining facility costs are due to the annualized capital costs and travel, lodging, and shipping to conduct the actual emission monitoring.

4.5.3 Annualizing Capital Costs and Determining O&M Costs

The capital costs related to monitoring emissions and archiving information consists of purchasing equipment for emission detection, emission measurement, and information storage. All costs are reported in 2006 U.S. dollars, and annualization was assumed over an equipment life of five years with a 7-percent interest rate. From these factors, a capital recovery factor of 24 percent was calculated using the formula provided as follows:

$$CRF = \frac{r(1+r)^n}{(1+r)^n - 1}$$

where CRF is the capital recovery factor, r is the interest rate, and n is the life expectancy in years. Table 4-14 summarizes the annualized capital costs associated with the monitoring program. Additionally, the table describes the annual costs of travel, lodging, and shipping—the only other non-labor costs related to the monitoring program.

Table 4-14 Monitoring Program Compliance Capital Costs and Other O&M

Element	Capital Cost	Annualized Capital Cost
Archiving		
Capital costs	Cost of archiving material per facility assumes cost of 1 file cabinet, 4-drawer vertical from Office Depot™ ($140), and 1 hard drive for data storage from Seagate™ ($95)	$57
Monitoring		
Equipment purchase	Screening equipment is represented by a nominal $100,000 cost for an infrared camera. It is assumed to be purchased by the contractors who will pass on the costs to as many facilities as they can provide a service each year.	$24,389
Equipment purchase	Screening equipment in the distribution segment is represented by a nominal $10,000 cost for a laser emission detector. It is assumed to be purchased by the local distribution companies over the infrared camera due to its low cost.	$2,439
Measurement		
Equipment purchase	Hotwire anemometers are required for compressor vents. It is assumed that the hotwire anemometer, a vinyl carrying case, an AC adapter, data acquisition software, and anemometer electronic data logger will be purchased.	$206
Traveling	Cost of traveling for an engineer to a facility from the home facility (therefore n-1 facilities to visit). Assuming travel cost is $0.485/mile, $150/night for overnight stay, $100/shipment for shipping equipment, and $100 per diem.	$0–$10,449[a]

[a]Annual travel costs are highly variable depending on the facility type, proximity, and ownership structure. Annual travel costs are estimated to vary from $0 to $10,449.

As shown in Table 4-14, the equipment leaks and vented emission detection methods vary depending on the size of the company and its facilities. In the case of companies with small operations and few facilities, the costs passed on by contractors will be spread over many facilities.

Each facility is assumed to purchase an adequate flow meter to measure the emission rates from compressor seal vents either at the pipe end, if accessible, or a flow measurement port installed at a suitable location capturing all vent emissions.

With the equipment costs per company determined, the final step was to divide company capital and O&M costs amongst individual facilities owned by a typical company.

Step 3, described previously, provided the proportion of facilities that fall in the small, medium, and large categories. By determining the companies that fall in the three categories, the average number of small, medium, and large facilities per company was determined. To convert the annualized capital costs and equipment purchases, the costs per equipment were attributed to the number of facilities that can be serviced (as determined the number of labor hours required to monitor a facility) each year, as shown in the equation as follows:

$$\frac{\$AnnualCapital}{Facility} = \left(\frac{\$AnnualCapital}{Equipment} \times \frac{\#ofEquipment}{Contractor}\right) \div \left(\frac{FacilitiesServiced}{Contractor}\right)$$

The travel, lodging, and shipping costs associated with monitoring several facilities spread over large regions were calculated using the assumed costs in Table 4-14. Expert judgment based on the number of teams using equipment and the necessity of travel versus shipping between facilities was used to determine these costs.

STEP 5: Estimate per Facility Costs for Each Threshold Level

The total reporting costs across each segment were determined by assigning model facility costs (small, medium, and large) to individual facilities in the respective industry segments based on relative size and determining total costs from the entire segment. This was done for only those facilities that exceeded the reporting threshold. Average cost per facility was then determined by dividing the total segment costs by the number of facilities that exceeded the reporting threshold—small, medium, and large. In the case of onshore production, field-level monitoring costs were aggregated to the total national burden, then distributed to operators at the basin-level based on production rates.

SECTION 5
SUBPART W ANALYSIS OF REPORTING RULE OPTIONS

For petroleum and natural gas systems, Subpart W, as shown in Table 5-1, the total cost of the reporting rule to the private sector is estimated to be $61.8 million in the first year and $19.0 million in subsequent years (2006$). These estimates include costs for reporters to monitor and report emissions and the costs for non-reporters to make a reporting determination. Of the costs to report emissions meeting or exceeding the threshold, equipment leaks and vented emissions are $40.1 million in the first year and $15.1 million in subsequent years. The estimates are based on the selected option for the final rule, which includes an annual emission-based threshold of 25,000 $MtCO_2e$ for each facility and a hybrid of direct measurement and source-specific calculation methodologies. Section 3.2 provides more details about the selected option.

EPA estimates that for Subpart W, the public-sector burden is about $1.1 million per year. Approximately $0.46 million per year is for verification activities, and about $0.66 million per year is for program implementation and developing and maintaining the data collection system. Program implementation activities include, but are not limited to, 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. In addition to total national costs for petroleum and natural gas systems, EPA also reports average cost-per-metric-ton to support additional analysis of the mandatory reporting programs. These costs are also shown on Table 5-1.

The first-year costs are higher due to initial program start-up costs—in particular; the investment to secure equipment and install flow measurement ports in vent lines to allow measurement. Initial-year costs are also higher because reporters are required to quantify various key sources (e.g., well liquids unloadings, well workovers, compressor wet seal degassing vents) in the first year; these sources are only required to be estimated bi-annually to mitigate long-term burden. The average cost per metric ton for all reporters is about $0.13/metric ton in the first year, declining to an average of $0.05/metric ton in subsequent years.

Table 5-1 National Cost Estimates for Petroleum and Natural Gas Systems

Subpart W – Petroleum and Natural Gas systems	NAICS	First Year $Million 2006	First Year Million $MtCO_2e$	First Year $/Mt	Subsequent Years $Million 2006	Subsequent Years Million $MtCO_2e$	Subsequent Years $/Mt
Process Emissions	211, 486	$40.1	253.9	$0.16	$15.11	253.9	$0.06
Combustion Emissions		$3.3	83.5	$0.04	$3.32	83.5	$0.04
Reporting Determination		$18.4	n/a	n/a	$0.58	n/a	n/a
Private Sector, Total		$61.8	337.4	$0.13[a]	$19.01	337.4	$0.05[a]
Public Sector, Total		$1.1	337.4	$0.003	$1.1	337.4	$0.003
TOTAL		$62.9	337.4	$0.13[b]	$20.11	337.4	$0.05[b]

Note:
[a] Excludes reporting determination for non-reporters; based on private sector cost to report process and combustion emissions ($43 million in first year, $18 million in subsequent years).

[b] Excludes reporting determination for non-reporters; based on public sector cost plus private sector cost to report process and combustion emissions ($44 million in first year, $19 million in subsequent years).

There is a notable reduction in reporting cost compared to the April 2010 proposal. The cost reduction resulted from changes such as providing equipment thresholds on several emission sources (e.g., tanks and dehydrators); simplified requirements for sampling and gas composition analysis; use of alternative leak detection equipment in some cases; and use of equipment-based emission factors instead of component-based emission factors. A slight decrease in the emissions expected to be reported also accounted for the lower cost estimate. The slight decrease in reported emissions resulted from data corrections in the transmission and LNG storage segments and use of different well property databases in onshore production. Table 5-2 summarizes these changes based on year-one costs for equipment leaks and vented emissions, and Table 5-3 summarizes these changes based on subsequent-year costs for equipment leaks and vented emissions.

Table 5-2 Equipment Leaks and Vented Emission Costs, Petroleum and Natural Gas Systems, First-Year Estimates

Source	Covered Emissions ($MtCO_2e$) April 2009 Proposed Rule	Covered Emissions ($MtCO_2e$) April 2010 Proposed Rule	Covered Emissions ($MtCO_2e$) Final Rule	Cost Million (2006$) April 2009 Proposed Rule	Cost Million (2006$) April 2010 Proposed Rule	Cost Million (2006$) Final Rule	Cost (2006$/metric ton) April 2009 Proposed Rule	Cost (2006$/metric ton) April 2010 Proposed Rule	Cost (2006$/metric ton) Final Rule
Original Six Segments[a]	85	94.3	78.7	$32.5	$26.7	$26.2	$0.38	$0.28	$0.33
Onshore Production	n/a	154.9	152.4	n/a	$27.7	$11.9	n/a	$0.18	$0.08
Local Distribution	n/a	22.7	22.7	n/a	$1.6	$2.0	n/a	$0.07	$0.09

Source	Covered Emissions ($MtCO_2e$)			Cost Million (2006$)			Cost (2006$/metric ton)		
	April 2009 Proposed Rule	April 2010 Proposed Rule	Final Rule	April 2009 Proposed Rule	April 2010 Proposed Rule	Final Rule	April 2009 Proposed Rule	April 2010 Proposed Rule	Final Rule
Total	**85**	**272**	**254**	$**32.5**	$**56.0**	**$40.1**	$**0.38**	$**0.21**	**$0.16**

[a] Offshore production, natural gas processing, natural gas transmission, underground natural gas storage, LNG storage; LNG import/export.

Table 5-3 Equipment Leaks and Vented Emission Costs, Petroleum and Natural Gas Systems, Subsequent-Year Estimates

Source	Covered Emissions ($MtCO_2e$)			Cost Million (2006$)			Cost ($/metric ton)		
	April 2009 Proposed Rule	April 2010 Proposed Rule	Final Rule	April 2009 Proposed Rule	April 2010 Proposed Rule	Final Rule	April 2009 Proposed Rule	April 2010 Proposed Rule	Final Rule
Original Six Segments[a]	85	94.3	78.7	$28.1	$11.8	$8.7	$0.33	$0.13	$0.11
Onshore Production	n/a	154.9	152.4	n/a	$8.6	$5.1	n/a	$0.06	$0.03
Local Distribution	n/a	22.7	22.7	n/a	$1.0	$1.3	n/a	$0.04	$0.06
Total	**85**	**272**	**254**	**$28.1**	**$21.4**	**$15.1**	**$0.33**	**$0.08**	**$0.06**

[a] Offshore production, natural gas processing, natural gas transmission, underground natural gas storage, LNG storage; LNG import/export.

In addition, EPA developed annualized estimates of the costs. For each segment, EPA calculated the present value of the labor and capital costs to monitor and report emissions over a 20-year time period using two discount rates (3 and 7 percent). The present value included the costs for facilities that do not meet the emissions threshold to make a reporting determination. EPA then calculated an annual value of the present value at discount rates of 3 and 7 percent. Table 5-4 presents the annualized cost estimates for each segment as well as the first-year and subsequent-year estimates.

Table 5-4 Annualized Cost Estimates for Petroleum and Natural Gas Systems (2006$)[a]

Segment	First Year National Cost ($Million)	First Year Cost ($/metric ton)	Subsequent Year National Cost ($Million)	Subsequent Year Cost ($/metric ton)	Annualized Cost[b] ($Million)	Annualized Cost[c] ($Million)
Processing	8.13	0.26	2.10	0.07	2.43	2.57
Transmission	16.87	0.40	6.49	0.15	7.02	7.26
Underground Storage	2.73	0.35	1.02	0.13	1.10	1.14
LNG Storage	0.70	0.41	0.26	0.15	0.28	0.29
LNG import/export	0.14	0.44	0.03	0.09	0.04	0.04
LDC	3.31	0.15	1.35	0.06	1.47	1.52
Onshore Production	26.58	0.12	7.54	0.03	8.61	9.05
Offshore Production	3.33	0.65	0.24	0.05	0.42	0.49
TOTAL (8 Segments)	61.78	0.18	19.01	0.06	21.36	22.34

[a] Includes determination costs for non-reporters. These estimates are conservative and should be viewed as an upper-bound because the determination costs were applied at the facility-level rather than the company-level. For example, for offshore production, determination costs were applied to each of the approximately 3,000 platforms in the Gulf of Mexico rather than to the roughly 86 operators in that region. See the memo, “Estimates of Determination Costs,” in the docket for complete details and additional determination cost estimates (EPA-HQ-OAR-2009-0923).
[b] The cost to report annualized over 20 years at 3 percent.
[c] The cost to report annualized over 20 years at 7 percent.

5.1 Evaluating Alternative Options for Implementation of the Rule

The selected option was evaluated based on a cost-effectiveness analysis. For example, in selecting the emission threshold, EPA compared the incremental emissions reported with the incremental costs (associated with the change in the facilities that would be required to report their emissions). Similarly, in selecting the reporting methodology option, EPA compared the change in uncertainty with the change in costs associated with different emission measurement/estimation techniques. The metrics used and the results of the cost-effectiveness analysis are discussed in the following information.

In addition, the final rule requires the determination of onshore reporting to be done with the assumption that reporting parties report emissions and, for onshore production, that they determine threshold on a basin level. In other words, owners or operators in the onshore production segment must report based on total emissions in all petroleum and natural gas production fields in a defined basin. EPA also examined an option to require onshore production companies to report on a field-level basis. This alternative would affect the total emissions reported as well as cost, and is evaluated in the following sections.

Six alternative options were therefore evaluated for this analysis. While the Agency believes that these alternatives represent the most likely variations in the selected option, EPA recognizes that, in some cases, particular interests may wish to evaluate more nuanced alternative options. To maintain transparency in the analysis, data necessary to conduct further alternative option analyses can be found in Section 4 of this document.

5.1.1 Analysis of Alternative Threshold Options

The threshold determines the number of entities required to report GHG emissions under Subpart W of the rule. The higher the threshold, the more entities that are excluded. It is assumed that the per-unit/entity cost does not change at different thresholds so that changes in the national cost estimates are driven by the number of reporting entities. The per-unit/entity costs outlined in Section 4 for Subpart W facilities, along with the estimates of numbers of covered entities at various thresholds, form the basis for this analysis. Two metrics are used to evaluate the cost-effectiveness of the emission threshold. The first is the average cost per metric ton of emissions reported. The second metric for evaluating the threshold option is the marginal cost of additional reported emissions ($/Mt$CO_2$e) relative to the option adopted in the final rule. To compute this metric, EPA computed the change in emissions reported by lowering or raising the threshold and divided this by the change in total reporting costs. Table 5-5 provides the cost-effectiveness analysis for the various thresholds.

Table 5-5 Summary of Threshold Cost-Effectiveness Analysis (First Year); Selected Hybrid Option Is 25,000 MtCO_2e

Threshold (MtCO_2e)	Facilities Required to Report	Total Costs (Million 2006$)	Downstream Emissions Reported (Million MtCO_2e/year)	Percentage of Total Downstream Emissions Reported	Average Reporting Cost[a] (2006$/Mt)	Cost Differential[a,b] (2006$/Mt)
1,000	12,622	$136.35	391	99%	$0.35	$1.73
10,000	4,400	$61.57	362	91%	$0.17	$0.73
25,000	2,786	$43.39	337	85%	$0.13	$0.00
100,000	1,062	$25.06	273	69%	$0.09	($0.28)

[a] Excludes determination costs for non-reporters. Inclusion of determination costs results in the following average reporting costs ($/Mt): 1,000 metric tons CO_2e = $0.38; 10,000 metric tons CO_2e = $0.22; 25,000 metric tons CO_2e = $0.18; and 100,000 metric tons CO_2e = $0.16.

[b] Cost difference relative to 25,000-metric-ton threshold

The analysis shows a cost reduction of $0.28 per metric ton by moving from the selected threshold of 25,000 MtCO_2e to a higher threshold (100,000 metric tons); the total emissions covered decrease significantly—about 16 percent. Similarly, by moving the threshold from

25,000 to 10,000, the difference increases by $0.73 per metric ton, and the emissions captured increase by 6 percent. Finally, lowering the threshold from 25,000 to 1,000 yields the highest increase in cost difference ($1.73 per metric ton) and increases the percentage of covered emissions by approximately 14 percent. Similar data are presented for subsequent years in Table 5-6.

Table 5-6 Summary of Threshold Cost-Effectiveness Analysis (Subsequent Years)

Threshold ($MtCO_2e$)	Facilities Required to Report	Total Costs (million 2006$/year)	Downstream Emissions Reported (Million $MtCO_2e$)	Percentage of Total Downstream Emissions Reported	Average Reporting Cost[a] (2006$/Mt)	Cost Differential[a,b] (2006$/Mt)
1,000	12,622	$71.60	391	99%	$0.18	$0.99
10,000	4,400	$29.48	362	91%	$0.08	$0.44
25,000	2,786	$18.43	337	85%	$0.05	$0.00
100,000	1,062	$9.61	273	69%	$0.03	($0.14)

[a] Excludes determination costs for non-reporters. Inclusion of determination costs results in the following average reporting costs ($/Mt): 1,000 metric tons CO_2e = $0.19; 10,000 metric tons CO_2e = $0.08; 25,000 metric tons CO_2e = $0.06; and 100,000 metric tons CO_2e = $0.04.
[b] Cost difference relative to 25,000-metric-ton threshold

Table 5-7 summarizes costs to report process and combustion emissions for all segments at four thresholds.

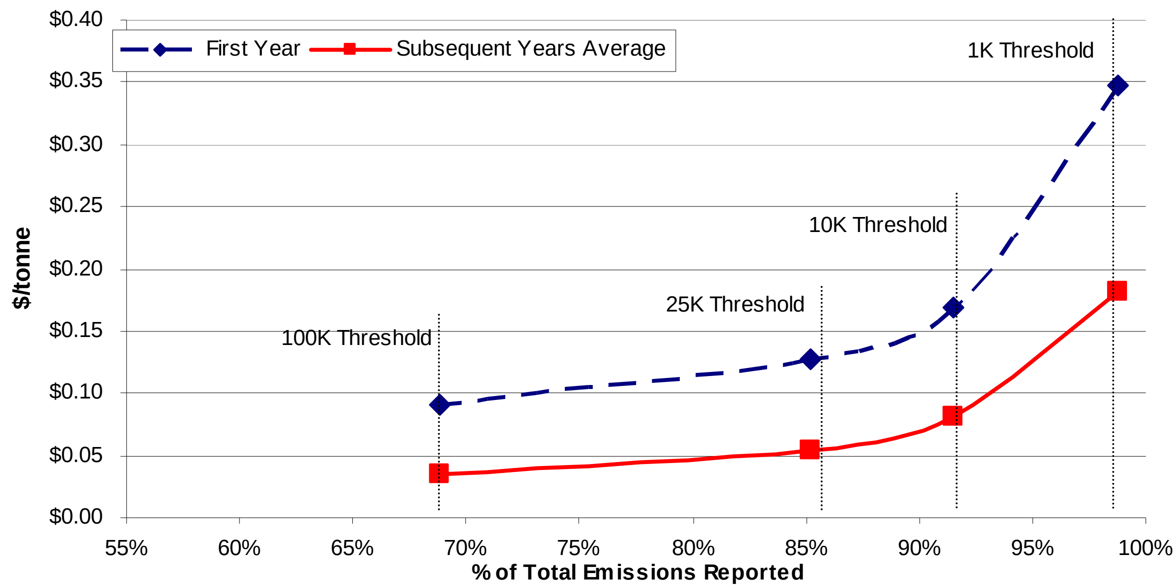
Table 5-7 Subpart W Cost Estimates by Threshold

Threshold	First Year		Subsequent Years	
	Million 2006$	$/Mt	Million 2006$	$/Mt
1,000 $MtCO_2e$	$136.35	$0.35	$71.60	$0.18
10,000 $MtCO_2e$	$61.57	$0.17	$29.48	$0.08
25,000 $MtCO_2e$	$43.39	$0.13	$18.43	$0.05
100,000 $MtCO_2e$	$25.06	$0.09	$9.61	$0.04

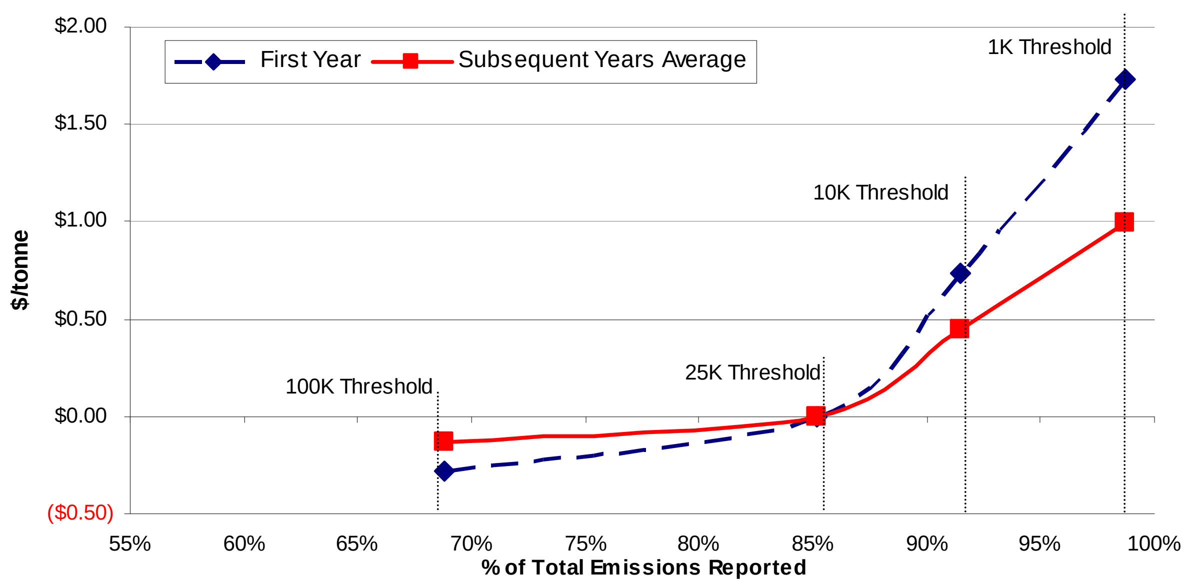
The selection decision weighed the marginal cost of capturing additional emissions with the percentage of emissions needed to accurately estimate national GHG emissions. This analysis is shown in Figure 5-1, which illustrates the total average cost per metric ton and the marginal cost per metric ton for Subpart W as a function of the percentage of total emissions reported.

Figure 5-1 Average Cost and Cost Differential per Metric Ton of Emissions Reported by Threshold

a. Average Cost



b. Cost Differential



5.1.2 Analysis of Alternative Monitoring Method Options

Each monitoring technique for which reporting costs were estimated for Subpart W in Section 4 was assumed in the burden analysis to provide the same estimate of total emissions by reporting facility. The methods proposed for monitoring emissions will differ, however, in their precision in estimating actual emissions. Therefore, the gain from increasing the cost of monitoring is to have more precise estimates of facility emissions. The methods considered for determining emissions ranged from applying average industry parameters (referred to as "population emission factors," or "default parameters") to material inputs or throughputs, to the use of direct measurement techniques. This section evaluates the change in cost and the change in accuracy for two alternative monitoring options for Subpart W. Generally speaking, under one of the alternatives, population factors would be used in lieu of direct measurements and facility-level estimates, and in the other option, direct measurements are required for all sources. EPA uses the terms "direct measurement" and "population factors" as shorthand to describe alternative options. For Subpart W, population emission factors and component count are the basis for "default factors." Estimated costs for each monitoring method are shown in Table 5-8.

For Subpart W, the direct measurement option greatly expands to use direct measurement of all vented and equipment leak sources. This is the methodology used in the April 2009 proposed rule. The costs associated with this case in the April 2009 proposed rule (which did not include the onshore production and natural gas distribution) resulted in Subpart W incurring 19 percent of the total costs in the GHG reporting rule to monitor and measure only 3 percent of the emissions.

These costs were re-estimated for the entire petroleum and natural gas segment in the final rule. These costs involve the use of direct measurement techniques, including metering of all vents, calibrated bagging, or use of high-volume samplers to measure equipment leaks and inaccessible leaks, and so on. These costs involve additional equipment as well as significantly higher labor costs. If the same direct measurement techniques were required in this rule, the costs would be particularly high for the new onshore production and natural gas distribution segments.

The overall costs for the direct measurement option are about $100 million (annually) higher than the selected option.

Table 5-8 Analysis of Alternative Monitoring Methods

Segment	Direct Measurement (DM)		Selected Option (Hybrid Approach)		Population Factors	
	First Year (million 2006$)	Subsequent Years (million 2006$)	First Year (million 2006$)	Subsequent Years (million 2006$)	First Year (million 2006$)	Subsequent Years (million 2006$)
Subpart W—Petroleum and Natural Gas Systems	$294.6	$126.9	$43.39	$18.43	$27.6	$17.4

For the "population factor" option, Subpart W sources were assumed to have emissions quantified entirely by the application of emission factors developed by GRI/EPA (1996) as the basis for estimates of CH_4 and non-combustion-related CO_2 emissions. These factors are used with a population count of equipment and components to arrive at a "population factor" cost estimate. The reduction in cost from the selected hybrid approach for this option is significant, with first-year costs declining by $15.8 million, and subsequent-year costs declining by $1.0 million.

5.1.2.1 Monitoring Method Uncertainty

The use of direct measurement methods would provide the most certain quantification of Subpart W emissions, assuming that measurements were taken using consistent monitoring protocols across reporters. If emission sources are measured as estimated in the burden analysis, there should be a high certainty level in the emissions quantified. Based on the analysis, however, the costs to gather and quantify these emissions would be very high.

The use of population-based factors would result in a significantly lower burden, although the certainty level of the emission determination would be very poor. Population-based factors determine the *potential* for emissions, assuming a percentage of known components that may leak based on previous (and dated) studies.

The final-rule-required option of using leak detection as well as a hybrid of spot direct measurement, engineering estimates, leaker emission factors, and population-based factors (for inaccessible sources) provides an emission estimate with significantly more certainty than population based factors at a more reasonable burden.

5.1.3 Sensitivity of Subsequent-Year Cost Estimates

National cost estimates for the final rule were developed based on the current population of entities in the petroleum and natural gas segment. The forward analysis ("subsequent years") assumes that the number of entities would remain relatively constant. Thus, the analysis assumes a stable population where all entities subject to Subpart W bear a single first-year cost and then repeated subsequent-year costs.

In reality, however, over time some existing facilities close or go out of business and new facilities come into existence, which is sometimes referred to as entry and exit in an industry. This phenomenon may affect the cost of the rule because as entities "turn over," the new entrants presumably will bear first-year costs that are slightly higher than subsequent-year costs.

The largest contribution to non-recurring first-year costs for Subpart W compliance is for flow measurement port installation in compressor seal vent lines. When a company goes out of business and sells its assets to either a new or existing business, these ports will already be installed; much of the first-year compliance costs will not apply to a company acquiring an already-reporting facility. The remainder of first-year costs that do not repeat are due to labor associated with reviewing the regulation and planning accordingly for compliance. These costs will not be necessary when an existing company, which already reports, acquires a reporting facility from a failing business. Only in the case of a new business entity acquiring an existing or new reporting station will these reviewing and planning first-year labor costs be necessary.

The reviewing and planning costs are minimal in comparison to the significant other first-year costs of reporting for Subpart W; therefore, the impact of business transitions on rule reporting costs for Subpart W are assumed minimal.

5.1.4 Summary of Alternative Options for Onshore Facility Definition

The final rule specifies that onshore petroleum and natural gas producers will report for each hydrocarbon basin. A basin is as identified by the American Association of Petroleum Geologists' three-digit Geologic Province Code. The reporters will be owners or operators in a basin; however, EPA also considered an alternate option to define a facility at a field-level. One such definition is available from the Energy Information Administration Petroleum and Gas Field Code Master. The field-level option would require aggregation of emissions by owners or operators at a field-level to apply the threshold. Table 5-9 and Table 5-10 show a detailed emission coverage and burden to reporter that would have been expected under a field-level facility definition.

Table 5-9 Emission Coverage and Entities Reporting for Field-Level Facility Definition (Onshore Production)

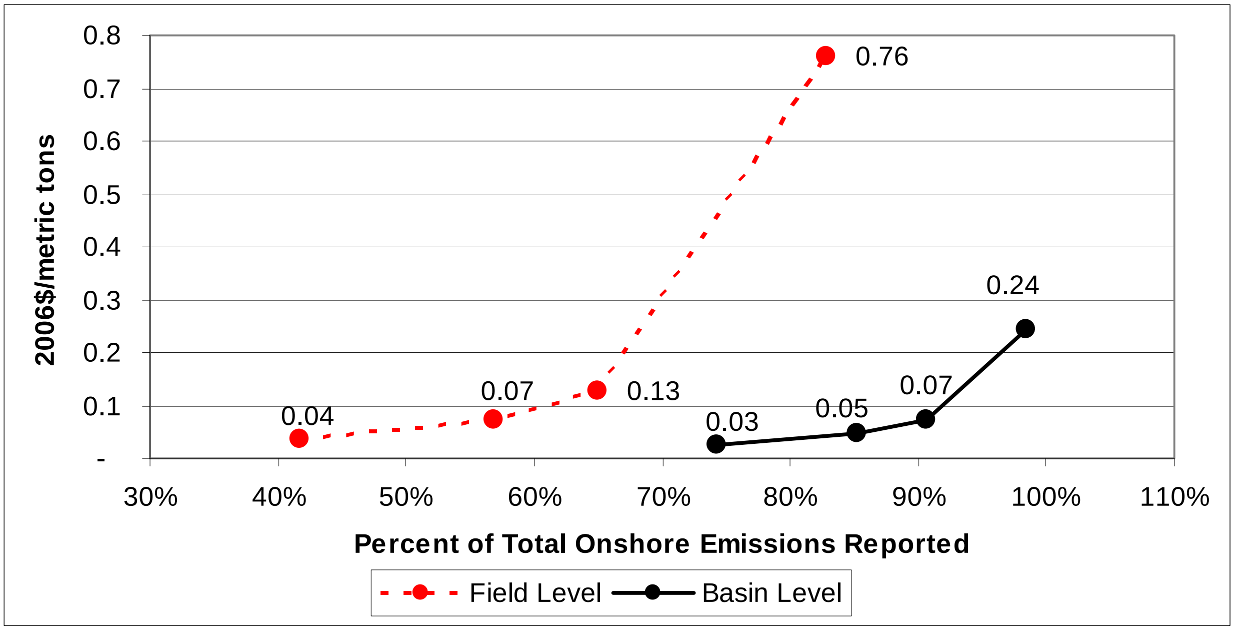
Threshold Level	Emissions Covered		Facilities Covered	
	Million $MtCO_2e$/ year	Percent	Number	Percent
1,000	219.1	83%	22,459	33%
10,000	171.9	65%	2,549	4%
25,000	150.3	57%	1,157	2%
100,000	110.4	42%	306	0.4%

Table 5-10 Equipment Leaks, Vented, and Combustion Emission Cost for Field-Level Facility Definition (Onshore Production)

Threshold Level	Equipment Leak and Vented Emission Costs (2006$)				Combustion Emission Costs (2006$)			
	First-Year Costs		Subsequent-Year Costs		First-Year Costs		Subsequent-Year Costs	
	Annualized Capital Cost	O&M Cost	Annualized Capital Cost	O&M Cost	Annualized Capital Cost	O&M Cost	Annualized Capital Cost	O&M Cost
1,000	$57.3	$7,274	$57.3	$3,069	$500	$1,700	$500	$1,700
10,000	$57.3	$8,855	$57.3	$3,834	$500	$1,700	$500	$1,700
25,000	$57.3	$10,334	$57.3	$4,549	$500	$1,700	$500	$1,700
100,000	$57.3	$14,963	$57.3	$6,622	$500	$1,700	$500	$1,700

Figure 5-2 presents a comparison of average costs (years 1, 2, and 3) and emission coverage at different thresholds for the field- and basin-level options. Specifically, it shows that the field-level option would result in a significantly lower coverage in emissions reported—57 percent at field-level versus 85 percent at the basin-level for a 25,000-$MtCO_2e$ threshold. In addition, the cost to report under the field-level definition is higher than under the basin-level definition at all thresholds, except at 100,000-$MtCO_2e$ threshold, at which field-level is lower. Emission coverage at the 100,000-$MtCO_2e$ threshold under a field-level definition is very low, however—42 percent. Finally, the number of entities reporting at a 25,000-$MtCO_2e$ threshold for basin-level definition is lower, at 981 in comparison to the 1,157 entities reporting for a field-level definition.

Figure 5-2 Summary of Basin vs. Field Decision



5.2 Assessing Economic Impacts on Small Entities

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

– Identifying affected entities under Subpart W.
– Selecting and describing the measures and economic impact thresholds used in the analysis.
– Determining a SISNOSE certification category.

5.2.1 Identifying Affected Segments and Entities

The affected entities covered by the rule were identified during the development of the cost analysis for the reporting rule. The Statistics of U.S. Businesses (SUSB) data provide national information on the distribution of economic variables by the size of entity. These data were developed in cooperation with, and partially funded by, the Office of Advocacy of the Small Business Administration (SBA) (SBA, 2008a). The data include the number of establishments (Table 5-11), employment (Table 5-12), and receipts (Table 5-13) and present information on *all* entities in an industry covered by Subpart W of the rule; however, many of these entities would not be expected to report under the selected option because they would fall below the 25,000 hybrid threshold. SUSB also provides this data by enterprise employment size. The census definitions in this data set are as follows:

- ***Establishment***: An establishment is a single physical location where business is conducted or where services or industrial operations are performed.
- ***Employment***: Paid employment consists of full- and part-time employees, including salaried officers and executives of corporations, who were on the payroll in the pay period including March 12, 2002. Included are employees on sick leave, holidays, and vacations; not included are proprietors and partners of unincorporated businesses.
- ***Receipts***: Receipts (net of taxes) are defined as the revenue for goods produced or distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- ***Enterprise***: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008c) apply to an establishment's "ultimate parent company," EPA assumes in this analysis that the "enterprise" definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses, and the terms are used interchangeably. EPA also reports the SBA size standard(s) for each industry group in order to facilitate comparisons and different thresholds.

Table 5-11 Number of Establishments by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Estab-lish-ments	Owned by Enterprises with: 1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	< 500 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; onshore natural gas processing	211	Crude Petroleum and Natural Gas Extraction	500	7,629	5836	456	292	6,584	60	64	31
Onshore natural gas transmission; underground natural gas storage; LNG storage; LNG import and export	486210	Pipeline Transportation of Natural Gas	[b]	1,936	81	27	61	169	36	2	20
Natural gas distribution	221210	Natural Gas Distribution	500	2,897	483	86	131	700	68	33	73

[a]The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Because the SBA's business size definitions (www.sba.gov/size) apply to an establishment's ultimate parent company, EPA assumes in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b]The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

Table 5-12 Number of Employees by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Employees	Owned by Enterprises with:						
					1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	< 500 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; onshore natural gas processing	211	Crude Petroleum and Natural Gas Extraction	500	88,280	19,336	12,113	11,656	43,105	2,421	3,551	1,061
Onshore natural gas transmission; underground natural gas storage; LNG storage; LNG import and export	486210	Pipeline Transportation of Natural Gas	[b]	37,450	347	157	1,053	1,834	[c]	[c]	[c]
Natural gas distribution	221210	Natural Gas Distribution	500	86,890	1,956	1,899	4,398	8,420	1,960	2,631	5,014

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (www.sba.gov/size) apply to an establishment's ultimate parent company, EPA assumes in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b]The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c]The U.S. Census Bureau has missing data for this employee range.

Table 5-13 Receipts by Affected Industry and Enterprise[a] Size: 2002

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Total Receipts ($Million)	Owned by Enterprises with: 1 to 20 Employees ($ thousands)	20 to 99 Employees ($ thousands	100 to 499 Employees ($ thousands)	< 500 Employees ($ thousands)	500 to 749 Employees ($ thousands)	750 to 999 Employees ($ thousands)	1,000 to 1,499 Employees ($ thousands)
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; onshore natural gas processing	211	Crude Petroleum and Natural Gas Extraction	500	$160,879	$7,573	$6,790	$9,609	$23,972	$4,609	$3,991	$2,805
Onshore natural gas transmission; underground natural gas storage; LNG storage; LNG import and export	486210	Pipeline Transportation of Natural Gas	[b]	$35,897	$1,035	$106[c]	$394[c]	$2,566	[c]	[c]	[c]
Natural gas distribution	221210	Natural Gas Distribution	500	$67,275	$2,524	$4,642	$2,878	$13,127	$865	$2,116	$3,757

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (www.sba.gov/size) apply to an establishment's ultimate parent company, EPA assumes in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c] The U.S. Census Bureau has missing data for this employee range. The receipts for the 1 to 20 range therefore underestimate true value.

5.2.2 Developing Small-Entity Economic Impact Measures

Because Subpart W covers businesses, the analysis generated a set of sales tests (represented as cost-to-receipt ratios)[20] for NAICS codes associated with the affected Subpart W segments. Although the appropriate SBA size definition should be applied at the parent company (enterprise) level, data limitations allowed EPA only to compute and compare ratios for a *model establishment* for eight *enterprise size* ranges (i.e., all categories, enterprises with 1 to 20 employees, 20 to 99 employees, 100 to 499 employees, 500 to 749 employees, less than 500 employees, 750 to 999 employees, and 1,000 to 1,499 employees). This approach allows EPA to account for differences in establishment receipts between large and small enterprises and differences in small business definitions across affected Subpart W industries. It is also a conservative approach because it does not screen out entities that would be below the reporting threshold. It is also conservative because an establishment's parent company (the "enterprise") may have other economic resources that could be used to cover the costs of the reporting program. It must be noted that the 1,000 to 1,499 employee category does not belong to the small business category; however, the category has been included to provide a comparison with small business cost-to-receipt ratios.

These sales tests examine the average establishment's total annualized mandatory reporting costs to the average establishment receipts for enterprises within several employment categories[21] (first-year costs: Table 5-14; subsequent-year costs: Table 5-15). The average entity costs used to compute the sales test are the same across all of these enterprise size categories. As a result, the sales test will overstate the cost-to-receipt ratio for establishments owned by small businesses because the reporting costs are likely lower than average entity estimates provided by the engineering cost analysis.

[20]Metrics for other small-entity economic impact measures (if applicable) would potentially include:

- Small governments (if applicable): "Revenue" test; annualized compliance cost as a percentage of annual government revenues.
- Small non-profits (if applicable): "Expenditure" test; annualized compliance cost as a percentage of annual operating expenses.

[21]The ratios for the 1 to 20 employee category are conservative because they include SUB data for enterprises with zero employees; these enterprises did not operate the entire year. Exclusion of enterprises with zero employees would result in slightly lower cost-to-sales ratios (e.g., 1.22% for NAICS 211).

Table 5-14 Establishment Sales Tests by Industry and Enterprise[a] Size: First-Year Costs

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($1,000/ entity)	All Enter-prises	Owned by Enterprises with:							
						1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	< 500 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; onshore natural gas processing	211	Crude Petroleum and Natural Gas Extraction	500	$17.1	0.08%	1.32%	0.11%	0.05%	0.47%	0.02%	0.03%	0.02%
Onshore natural gas transmission; underground natural gas storage; LNG storage; LNG import and export	486210	Pipeline Transportation of Natural Gas	b	$15.7	0.08%	0.12%	0.40%[c]	0.24%[c]	0.10%	**c**	**c**	**c**
Natural gas distribution	221210	Natural Gas Distribution	500	$13.9	0.06%	0.27%	0.03%	0.06%	0.07%	0.11%	0.02%	0.03%

[a]The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments. Since the SBA's business size definitions (www.sba.gov/size) apply to an establishment's ultimate parent company, EPA assumes in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b]The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c]The U.S. Census Bureau has missing data for this employee range; some estimates were possible using partial data. The receipts for these categories underestimate true value.

Table 5-15 Establishment Sales Tests by Industry and Enterprise[a] Size: Subsequent-Year Costs

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average Cost Per Entity ($/entity)	All Enter-prises	Owned by Enterprises with: 1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	< 500 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; onshore natural gas processing	211	Crude Petroleum and Natural Gas Extraction	500	$7.5	0.04%	0.58%	0.05%	0.02%	0.21%	0.01%	0.01%	0.01%
Onshore natural gas transmission; underground natural gas storage; LNG storage; LNG import and export	486210	Pipeline Transportation of Natural Gas	b	$6.9	0.04%	0.05%	0.18%[c]	0.11%[c]	0.05%	c	c	c
Natural gas distribution	221210	Natural Gas Distribution	500	$9.2	0.04%	0.18%	0.02%	0.04%	0.05%	0.07%	0.01%	0.02%

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (www.sba.gov/size) apply to an establishment's ultimate parent company, EPA assumes in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

[b] The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c] The U.S. Census Bureau has missing data for this employee range; some estimates were possible using partial data. The receipts for these categories underestimate the true value, which results in conservative estimates of cost-to-sales ratios.

5.2.3 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. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

For the purposes of assessing the impacts of Subpart W of the rule on small entities, EPA 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, independently owned and operated, and not dominant in its field.

EPA believes the selected thresholds maximize the rule coverage with 85 percent of all U.S. petroleum and natural gas systems emissions reported by approximately 2,786 reporters, while keeping reporting burden to a minimum and excluding small emitters. Furthermore, many Subpart W industry stakeholders with whom EPA met expressed support for a 25,000-MtCO_2e threshold because it sufficiently captures the majority of GHG emissions in the United States while excluding smaller facilities and sources. After considering the economic impact of the final rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. As shown in Table 5-14 and Table 5-15, the average ratio of annualized reporting program costs to receipts of establishments owned by model small enterprises was less than 1 percent for industries presumed likely to have small businesses covered by the reporting program.

The only exception to this is the ratio for 1 to 20 employee range for crude petroleum and natural gas extraction, which is greater than 1 percent but less than 2 percent. As previously noted, the small business analysis does not screen out entities that would be below the reporting threshold. Based on further analysis of production data in HPDI, EPA estimates that in most cases, the small enterprises have very small operations (such as a single family owning a few production wells) that are highly unlikely to cross the 25,000-MtCO_2e reporting threshold.

In other cases, a small enterprise (less than 20 employees) may own large operations but conduct nearly all of its operations through service providers, so that it has few employees of its own. Such enterprises, however, tend to have higher annual revenues than those with small operations and therefore have lower cost-to-sales ratios. The review of production data by operator in HPDI shows a ratio of less than one percent for the operators expected to meet the reporting threshold.

5.3 Synopsis of Benefits

Under the Mandatory GHG Reporting Rule, EPA requires the collection and verification of emission data from Subpart W facilities. This section reviews the benefits of a mandatory reporting program for Subpart W facilities based on previous experience with emission inventory programs in the United States and abroad.

Recent policy discussions have highlighted potential benefits to society of the mandatory GHG reporting program (Pew, 2008). Benefits to the public include: building public confidence through clear and transparent emission measures and reports and making petroleum and natural gas facilities accountable for their equipment leaks and vented emissions. A GHG reporting system will also have the benefit of providing policymakers and analysts with a data set that is comprehensive for the petroleum and natural gas industry if reporting is conducted under Subpart W and other applicable subparts. Benefits to the industry include: identifying cost-effective GHG reduction opportunities and disclosing information, which provides firms with incentives to reduce emissions voluntarily and provides emission data to service industries, such as insurance and financial markets. Availability of emission information to the public, consumers, investors, corporations, and government regulators provides a sound basis for future policy analysis, which benefits society as a whole. Accurate and transparent information is necessary for the implementation of efficient approaches that meet environmental goals with the lowest cost to the economy.

SECTION 6
STATUTORY AND EXECUTIVE ORDER REVIEWS

This section describes EPA's compliance with applicable executive orders and statutes during the development of Subpart W of the Mandatory GHG 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 raises 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.

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 2376.02.

EPA plans to collect complete and accurate facility-level GHG emissions from the petroleum and natural gas industry. Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions. Through data collected under this rule, EPA will gain a better understanding of the relative emissions of different segments of the petroleum and natural gas industry and the distribution of emissions from individual facilities within those industries. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and actions that facilities are already taking to reduce emissions. Additionally, EPA will be able to track the trend of emissions from facilities within the petroleum and natural gas industry over time, particularly in response to policies and potential regulations. The data collected by this rule will improve EPA's ability to formulate climate change policy options and to assess which segments of the petroleum and gas industry would be affected, and how these segments would be affected by the options.

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 data collected under CAA section 114 cannot generally be claimed as CBI and will be made public.

The projected cost and hour burden for non-Federal respondents is $27.7 million and 396,474 hours per year. The estimated average burden per response is 90.71 hours; the frequency of response is annual for all respondents that must comply with the final rule's reporting requirements; and the estimated average number of likely respondents per year is 2,786. The cost burden to respondents resulting from the collection of information includes the total capital cost annualized over the equipment's expected useful life (averaging $0.74 million), a total operation and maintenance component (averaging $1.7 million per year), and a labor cost component (averaging $25.3 million per year)[22].

Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the EIA for these subparts because the information collection request (ICR) costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the EIA for the subparts for the first year of the rule and for subsequent years of the rule. In addition, the ICR focuses on respondent burden, while the EIA includes both national compliance costs and the burden for EPA to implement the rule.

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.

[22] Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the Economic Analysis because the ICR costs represent the average cost over the first three years of the proposed rule, but costs are reported elsewhere in the Economic Analysis for the first year of the proposed rule and for subsequent years of the proposed rule. In addition, the ICR focuses on respondent burden, while the Economic Analysis includes EPA Agency costs.

6.3 Regulatory Flexibility Act

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 this final 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 that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

The small entities directly regulated by this final rule include small businesses in the petroleum and gas industry, small governmental jurisdictions and small non-profits. EPA has determined that some small businesses will be affected because their production processes emit GHGs exceeding the reporting threshold.

For affected small entities, EPA conducted a screening assessment comparing compliance costs for affected industry segments to petroleum and gas-specific data on revenues for small businesses. This ratio constitutes a "sales" test that computes the annualized compliance costs of this final rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., 1 percent or 3 percent). The cost-to-sales ratios were constructed at the establishment level (average compliance cost for the establishment/ average establishment revenues).

As shown in Table 5-14, the average ratio of annualized reporting program costs to receipts of establishments owned by model small enterprises was less than 1 percent for industries presumed likely to have small businesses covered by the reporting program. It is important to note that this analysis does not screen out entities that would be below the reporting threshold. Although the costs to receipts for entities in onshore production with 1-20 employees is slightly over 1 percent, most of these facilities would likely not exceed the 25,000 $mtCO_2e$ threshold, a threshold supported by many stakeholders as one that sufficiently captures the majority of GHG emissions while excluding small facilities.

EPA also concluded that the final rulemaking would not affect a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field. Specifically, the data listing entities in each segment of the petroleum and natural gas industry did not include any non-profit entities.

In addition, EPA determined that the final rulemaking would not have a significant impact on small governmental jurisdictions. EPA determined that one segment of the petroleum and natural gas industry might include small governments affected by the final rulemaking. A comparison of the compliance costs to the revenue of potentially affected small governmental jurisdictions revealed that the costs of the rule are less than 1 percent of revenues.

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 final rule on small entities. For example, EPA determined appropriate thresholds that reduce the number of small businesses reporting. In addition, EPA allows different monitoring methods for different emissions sources, requiring direct measurement only for selected sources. Also, EPA intends to provide a screening tool that will help small businesses make a reporting determination (see Section II.F.6 of the preamble). Finally, EPA is establishing annual instead of more frequent reporting.

Through comprehensive outreach activities prior to proposal of the initial rule, EPA held approximately 100 meetings and/or conference calls with representatives of the primary audience groups, including numerous trade associations and industries in the petroleum and gas industry that include small business members. EPA's outreach activities prior to proposal of the initial rule are documented in the memorandum, Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule, located in Docket No. EPA-HQ-OAR-2008-0508-053. After the initial proposal, EPA posted a guide for small businesses on the EPA GHG reporting rule website, along with a general fact sheet for the rule, information sheets for every source category, and an FAQ document. EPA also operated a hotline to answer questions about the final rule. EPA continued to meet with stakeholders and entered documentation of all meetings into the docket.

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

EPA has therefore concluded that this final action will not have a significant economic impact on a substantial number of small entities.

6.4 Unfunded Mandates Reform Act

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any one year. EPA estimated the cost to individual facilities that may have to report to this final rule using actual facility characteristics such as throughput and size. EPA also determined the costs to non-reporters for determination to report. The sum of these costs for the entire industry has been estimated to be less than $100 million. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Based on EPA's analysis of the rule's impact on small entities, the Agency determined that natural gas distribution is the only industry segment that would potentially have small governments affected by the rule. In this segment, however, the facilities owned or operated by small governments are expected to be too small to trigger the 25,000 metric tons CO_2e reporting threshold.

6.5 Executive Order 13132: Federalism

This action 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 directly to petroleum and natural gas facilities that emit greenhouse gases. Few, if any, State or local government facilities would be affected. 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 action.

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

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. EPA conducted an analysis to determine potential impact of this action on tribes that own or operate petroleum and natural gas systems (EPA-HQ-OAR-2009-0923-XXX). First, EPA analyzed a comprehensive listing of all operators of petroleum and natural gas systems in the United States in conducting the threshold analysis. In a separate analysis, EPA researched additional available data to determine which tribal entities may own or operate petroleum and natural gas systems that could be impacted by this final action. As a result of those analysis, EPA found one tribe that may potentially be impacted by this final action. Finally, during the comment period for the April 2010 proposal, EPA received comment from one tribe, Southern Ute, which were specific to the proposed reporting methodologies.

As further discussed in the 2009 final rule that established the Greenhouse Gas reporting program, EPA believes that there are minimal impacts to tribes. Tribes could be required to submit an annual GHG report for any facility they own or operate that is subject to the rule. Specifically, tribes that own or operate oil and gas operations could be required to report emissions under this rulemaking. It should be noted that the owner or operator of any privately owned sources located on a reservation would be required to report for any applicable facility.

EPA sought opportunities to provide information to tribal governments and representatives during rule development. As stated in IV.F of the preamble, Executive Order 13175: Consultation and Coordination with Indian Tribal Governments of 40 CFR part 98, and in consultation with EPA's American Indian Environment Office, EPA's outreach plan for the Greenhouse Gas Reporting Rule included tribes. EPA conducted several conference calls with Tribal organizations during the proposal phase of Part 98. For example, EPA staff provided information to tribes through conference calls with multiple Indian working groups and organizations at EPA that interact with tribes and through individual calls with two Tribal board members of The Climate Registry (TCR).

In addition, EPA prepared a short article on the Greenhouse Gas Reporting Program that appeared on the front page of a Tribal newsletter—Tribal Air News—that was distributed to EPA/OAQPS's network of Tribal organizations. EPA gave a presentation on various climate efforts, including the Greenhouse Gas Reporting Program, at the National Tribal Conference on Environmental Management on June 24-26, 2008. In addition, EPA distributed copies of a short information sheet 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 final Part 98. It was posted on the Greenhouse Gas Reporting Program website and published in the Tribal Air Newsletter.

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

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. Also, this is not an economically significant rule under EO 12866, and thus EO 13045 does not apply.

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 final rule is not likely to have any adverse energy effects. This final rule relates to monitoring, reporting and recordkeeping at petroleum and gas facilities that emit over 25,000 mtCO_2e and does not impact energy supply, distribution or use. Therefore, EPA concludes that this final 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, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA provides the flexibility to use any one of the voluntary consensus standards from at least seven different voluntary consensus standards bodies, including the following: ASTM, ASME, ISO, Gas Processors Association, and American Gas Association. These voluntary consensus standards will help facilities monitor, report, and keep records of greenhouse gas emissions. No new test methods were developed for this final rule. Instead, EPA reviewed existing rules for source categories and voluntary greenhouse gas programs and identified existing means of monitoring, reporting, and keeping records of greenhouse gas emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including many for combustion sources such as methods to analyze fuel and measure its heating value; methods to measure gas or liquid flow; and methods to gauge and measure petroleum and petroleum products.

By incorporating voluntary consensus standards into this final rule, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for measuring greenhouse gas emissions.

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 this 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 because it is a rule addressing information collection and reporting procedures.

SECTION 7
CONCLUSIONS AND IMPLICATIONS

In this EIA, EPA has examined the regulatory background, the development of the mandatory GHG meporting rule for Subpart W, and estimated costs and benefits of implementing this subpart. This section presents EPA's overall conclusions.

7.1 Discussion of Results

EPA has developed this final rule in response to language contained in the FY 2008 Consolidated Appropriations amendment (December 26, 2007), which authorized funding for EPA to publish the rule on an accelerated schedule. The major market failure that the rule is designed to address is one of inadequate or asymmetric information: while existing state and federal programs collect similar data, the resulting data are neither comprehensive nor consistent for Subpart W sources. As such, they are an inadequate basis for the formation or evaluation of future climate policy that will impact the petroleum and natural gas segments.

7.1.1 Development of the Proposed Rule

EPA examined several regulatory alternative scenarios that were developed by varying options across two program dimensions—threshold and monitoring methodology—that were finalized in today's rule. The final rule calls for:

- A threshold of 25,000-MtCO_2e threshold for all facilities.
- A hybrid methodology, including use of limited direct spot measurement, facility-specific calculation methods, and use of emission factors (leaker and population factors).

Other scenarios evaluated during the development of the proposal included the following:

1. A 1,000-MtCO_2e threshold; selected options for methodology, frequency, and verifier.
2. A 10,000-MtCO_2e threshold; selected options for methodology, frequency, and verifier.
3. A 100,000-MtCO_2e threshold; selected options for methodology, frequency, and verifier.
4. The measurement variable is changed to direct spot measurement; selected option for threshold.

5. The measurement variable is changed to default emission factors; selected option for threshold.

7.1.2 Affected Source Categories

EPA considered direct emitters of equipment leaks and vented GHGs under Subpart. From these emission sources, EPA identified eight segments under the Subpart W source category for which costs and impacts were examined.

7.2 Assessment of Costs and Benefits of the Mandatory Greenhouse Gas Reporting Rule

7.2.1 Estimated Costs and Impacts of the Mandatory Greenhouse Gas Reporting Program

Under the final rule, EPA estimates that 2,786 entities would be covered by Subpart W of the rule, directly emitting 337 million $MtCO_2e$ per year. The total annualized costs incurred under the rule by these entities would be $61.8 million for the first year and $19.0 million for subsequent years.

Overall, economic impacts on industry segments are measured by comparing per-entity costs with average per entity receipts. These cost-to-sales ratios are less than 1 percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (e.g., establishments owned by a business with 20 or more employees) and small government entities. This analysis enables EPA to determine that the final rule will not have a significant economic impact on a substantial number of small entities. Overall, Subpart W of the rule will impose national costs exceeding $61.8 million in the first year and $19.0 million in subsequent years; the costs will be widely dispersed throughout the economy and relatively low on a per-entity basis. The estimated national costs represent less than 0.001 percent of 2007 gross domestic product. Thus, EPA does not estimate that there will be significant impacts on the economy in general or on individual segments or small entities within Subpart W.

7.2.2 Summary of Qualitative Benefits Assessment

EPA did not quantify the estimated benefits of the final rule. Instead, a qualitative assessment was performed, based on information from the literature and previous benefits assessments of existing emission inventory programs.

Recent policy discussions have highlighted potential benefits to society of the GHG reporting program (Pew, 2008). Benefits to the public include building public confidence through clear and transparent emission measures and reports and making facilities accountable for their emissions. Benefits to petroleum and natural gas industry include identifying GHG reduction opportunities and disclosing information, which provides firms with incentives to reduce emissions voluntarily and provides emission data to service industries, such as insurance and financial markets. A GHG reporting system will also have the benefit of providing policymakers and analysts with a comparable data set that is comprehensive and reduces the potential for policy bias. In addition, a mandatory reporting system is a key element to an overall GHG policy; no effort can succeed without it.

Studies published by the Organization for Economic Co-operation and Development (OECD) (2005) and U.S.EPA (2003) have documented benefits to various stakeholders, including the public, industry, investors, and government, of existing pollutant release and transfer registers (PRTRs). These benefits are likely similar to the benefits that would be experienced as a result of the mandatory GHG reporting rule, and thus they provide a basis for a qualitative characterization of those benefits. The studies examined in Section 5 of this EIA describe the following types of benefits:

- Public
  - More information will lead to increased levels of trust towards government and industry where there are right-to-know laws concerning emissions.
  - More information will enable citizens to negotiate directly with emitters.
  - More information will enable environmentally aware consumers to alter their consumption habits based on GHG emissions of producers.
- Industry
  - Public relations: Having independent, verifiable data to present to the public would demonstrate appropriate environmental stewardship.
  - Standardization: Uniform industry standards would reduce the cost of reporting relative to non-uniform, jurisdiction-specific, and allow facilities to benchmark their performance against other similar facilities.
  - Potential cost savings: Mandatory monitoring may uncover previously unmeasured wasteful processes, yielding cost-saving conservation opportunities that would offset some of the costs of monitoring.

- Potential customer data for service industries: Information about GHG-emitting firms will be useful for firms that market emission-reduction technologies, and to insurance companies for assessing risk.

- Investors

  - Information about emissions will enable investors to implement socially responsible investing using GHG emission information if they so choose.

- Government

  - Policy development: The greatest benefit to government of mandatory GHG reporting is the comprehensive, consistent data it would provide, enabling government to develop accurate, informed future GHG policy.

  - Comparability: A mandatory system would reduce the difficulties associated with comparing across different reporting standards across states or programs.

  - Compliance and policy evaluation: Publicly available nationwide data on GHG emissions will enable government to develop and robustly evaluate environmental policies, and to ensure compliance with the policies once implemented.

7.3 What Did We Learn through This Analysis?

EPA's examination of the costs and benefits of the provisions in Subpart W of the mandatory GHG reporting rule revealed that the final rule will impose an estimated $30.9 million (based on average of first-year and subsequent-year costs) in monitoring, recordkeeping, and reporting costs on emitters of GHGs that are widely distributed throughout the U.S. economy. Impacts of the costs on individual segments and entities are expected to be generally small, comprising less than 1 percent of entity receipts and approximately 0.001 percent of 2007 gross domestic product. Thus, despite the overall national costs, macroeconomic impacts are not anticipated, and EPA does not believe that the final rule will impose significant economic impacts on a substantial number of small entities.

A review of the literature enabled EPA to characterize the expected types of benefits, which will be experienced by stakeholders, including the public, industry, investors, and government. Based on this qualitative assessment and evidence from other existing programs, EPA expects the benefits of the final rule to be substantial.

SECTION 8
SOURCES CONSULTED

API. (2004). *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*. American Petroleum Institute. www.api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf.

API. (2008). *Addendum to Impact Assessment of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry*. American Petroleum Institute. http://www.api.org/Newsroom/upload/IA_ICF_L_W_REPORT_FINAL_08_4_29_pdf.pdf

API. (2007). *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology*. American Petroleum Institute. www.api.org/aboutoilgas/sectors/explore/upload/API_CO2_Report_August-2007.pdf.

Beierle, T. C. (2003). *The Benefits and Costs of Environmental Information Disclosure: What Do We Know About Right-to-Know?* Resources for the Future, RFF Discussion Paper 03-05.

Bureau of Economic Analysis. (2007). *Table 1.1.9. Implicit Price Deflators for Gross Domestic Product*. www.bea.gov/bea/dn/nipaweb/TableView.asp#Mid.

Bylin, C. (EPA), et. al. (2009). *Methane's Role in Promoting Sustainable Development in Oil and Natural Gas Industry*. Presented at 24th World Gas Conference, Buenos Aires, Argentina.

California Climate Action Registry (CCAR). (2007). *General Reporting Protocol*. www.climateregistry.org.

DOE/NETL. (2008). *Storing CO_2 with Enhanced Oil Recovery*. U.S. Department of Energy /National Energy Technology Laboratory 402/1312/02-07-08.

DOE/NETL. (2009). *Electricity Use of Enhanced Oil Recovery with Carbon Dioxide (CO_2-EOR*). U.S. Department of Energy/National Energy Technology Laboratory. www.netl.doe.gov/energy-analyses/pubs/Electricity%20Use%20of%20CO2-EOR.pdf.

DOT. (2006) *Distribution, Transmission, and Liquid Annual Data*. U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Disan06.zip

EIA. (2006). *Underground Storage Field Level Data From EIA-191A*. U.S. Energy Information Administration. www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/undrgrnd_storage.html.

EIA. (2008). *Official Energy Statistics from the U.S. Government Glossary*. U.S. Energy Information Administration. www.eia.doe.gov/glossary/index.html.

EPRI. (1999). *Enhanced Recovery Scoping Study.* Electric Power Research Institute. www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf.

FERC. (2008). *Existing LNG Terminals*. Federal Energy Regulatory Committee. http://ferc.gov/industries/lng.asp.

BOEMRE. (2000). *Gulfwide Emission Inventory*. Bureau of Ocean Energy Management, Regulation, and Enforcement. www.gomr.boemre.gov/homepg/regulate/environ/airquality/goad.html.

GRI. (1992). *GRI Report, Methane Emissions from the Natural Gas Industry, Volumes 1- 15.* Gas Research Institute. U.S. Energy Information Agency/U.S. Department of Energy.

GRI. (1996). *GRI Report, Methane Emissions from the Natural Gas Industry, Volumes 1- 15.* Gas Research Institute. U.S. Environmental Protection Agency.

GTI. (1999). *Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases,* 2^{nd} Edition CD-ROM. Gas Research Institute. U.S. Energy Information Agency/U.S. Department of Energy

GTI. (2007). *The World Energy Source Book – Fourth Edition, An Encyclopedia of the World LNG Industry,* GTI 07/0002. Gas Research Institute. U.S. Energy Information Agency/U.S. Department of Energy

HPDI® Database. (2006). Data Retrieved October 2009.

IIASA. (2007). *Uncertainty in Greenhouse Gas Inventories. IIASA Policy Brief No. 1.* International Institute for Applied Systems Analysis. www.iiasa.ac.at/Admin/PUB/policy-briefs/pb01-web.pdf.

INGAA. (2008). *Greenhouse Gas Emissions Estimation Guidelines for Natural Gas Transmission and Storage*. Volume 1. Interstate Natural Gas Association of America. www.ingaa.org/cms/33/1060/6435.aspx.

IPCC. (2006). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. Intergovernmental Panel on Climate Change. www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

Lasser Production Data, Version 3.0.8 (2006).

MMS. (2000). *GOADS Summary Access File, Final GOADS Emissions Summaries.* Minerals Management Service.

www.gomr.mms.gov/homepg/regulate/environ/airquality/gulfwide_emission_inventory/2000GulfwideEmissionInventory.html.

NESHAP. *40 CRF Part 63*. (2008). National Emissions Standards for Hazardous Air Pollutants. www.tceq.state.tx.us/permitting/air/rules/federal/63/63hmpg.html.

Nicholas Institute for Environmental Policy Solutions. (2008). *Size Thresholds for Greenhouse Gas Regulation: Who Would Be Affected by a 10,000-ton CO_2 Emissions Rule?* Duke University. www.nicholas.duke.edu/institute/10Kton.pdf.

Oil & Gas Journal. (2006). *Worldwide Gas Processing Survey*. www.ogj.com.

Oil & Gas Journal. (2006). *EOR/Heavy Oil Survey*.

Oil & Gas Journal. (2007). *Worldwide Gas Processing Survey*. www.ogj.com.

OPS. (2006). *Transmission Annuals Data*. http://ops.dot.gov/stats/DT98.htm.

Organization for Economic Co-Operation and Development (OECD). 2005. "Uses of Pollutant Release and Transfer Register Data and Tools for Their Presentation—A Reference Manual." *Series on Pollutant Release and Transfer Registers No. 7*. http://www.olis.oecd.org/olis/2005doc.nsf/LinkTo/NT00000AA2/$FILE/JT00177567.PDF.

Pew Center on Global Climate Change. (2002). *The Feasibility of Greenhouse Gas Reporting.* www.pewclimate.org/policy_center/analyses/ghg_feasibility.cfm.

Pew Center on Global Climate Change. (2008). "Greenhouse Gas Reporting and Disclosure: Key Elements of a Perspective U.S. Program." *Innovative Policy Solutions to Climate Change. In Brief, No. 3*. www.pewclimate.org/docUploads/policy_inbrief_ghg.pdf.

Rice, C. (2002). *Wage Rates for Economic Analyses of the Toxics Release Inventory Program.* Analytical Support Branch, Environmental Analysis Division, Office of Environmental Information, U.S. Environmental Protection Agency.

Spring, P.S., R.H. Hugman, and E.H. Vidas. (1999). *Unconventional Gas Field, Reservoir, and Completion Analysis of the Continental United States – 1998 Update.* Gas Research Institute, Contract 5097-210-4018.

State of New Mexico. (2008). New *Mexico Green House Gas Mandatory Emissions Inventory Emissions Quantification Procedures*. www.nmenv.state.nm.us/aqb/ghg/documents/NM_GHGEI_quantif_proced2008.pdf.

TCEQ. (2009). *Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluations.* Texas Commission on Environmental Quality, Air Quality Division. TX: 1-73.

TERC. (2009). *VOC Emissions from Oil and Condensate Storage Tanks.* Texas Environmental Research Consortium. The Woodlands, TX: 1-34 http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf.

The Climate Registry. (2007). *General Reporting Protocol for the Voluntary Reporting Program*. www.theclimateregistry.org.

U.S. Department of Labor, Bureau of Labor Statistics. (2003). *National Compensation Survey - Compensation Cost Trends, Employer Cost for Employee Compensation (ECEC), Customized Tables*. < http://www.bls.gov/eci/>

U.S. EPA. (2002). *Wage Rates for Economic Analyses of the Toxics Release Inventory Program*. U.S. Environmental Protection Agency, Analytical Support Branch, Environmental Analysis Division, Office of Environmental Information.

U.S. EPA. (2003). *How Are the Toxics Release Inventory Data Used?—Government, Business, Academic and Citizen Uses* (EPA-2600-R-002-004). U.S. Environmental Protection Agency. www.epa.gov/tri/guide_docs/pdf/2003/2003_datausepaper.pdf.

U.S. EPA. (2009). *Final Mandatory Reporting of Greenhouse Gases Rule.* U.S. Environmental Protection Agency. Washington D.C. Docket ID No. EPA-HQ-OAR-2008-0508-2278.

U.S. EPA (2009). *Preamble to the Mandatory Greenhouse Gas Reporting Rule*. U.S. Environmental Protection Agency. EPA-HQ-OAR-2008-0508-001.

U.S. EPA (2009). *Technical Support Document to the Mandatory Greenhouse Gas Reporting Rule*. U.S. Environmental Protection Agency. EPA-HQ-OAR-2008-0508-001.

U.S. EPA. (2008). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006*. U.S. Environmental Protection Agency #430-R-08-005c. www.epa.gov/climatechange/emissions/downloads/08_CR.pdf.

U.S. EPA. (2008). *Natural Gas Methane Units Converter*. U.S. Environmental Protection Agency. www.epa.gov/gasstar/pdf/unitconverter_final.pdf.

U.S. Small Business Administration. (2008a). *Firm Size Data from the Statistics of U.S. Businesses: U.S. Detail Employment Sizes: 2002.* www.census.gov/csd/susb/download_susb02.htm.

U.S. Small Business Administration . (2008b). *Firm Size Data from the Statistics of U.S. Businesses: Dynamic Data by Births, Deaths, Growth, and Decline, U.S. Industry Data: 2003-2005.* www.sba.gov/advo/research/data.html.

U.S. Small Business Administration. (2008c). *Table of Small Business Size Standards Matched to North American Industry Classification System Codes. Effective March 11, 2008.* www.sba.gov/services/contractingopportunities/sizestandardstopics/ size/index.html.

WCI. (2008). *WCI Meetings and Events*. Western Climate Initiative. www.westernclimateinitiative.org/events-and-meetings/categoriesdetailed.

World Resources Institute and World Business Council for Sustainable Development. (2008). *Corporate Accounting and Reporting Standard*. www.ghgprotocol.org/standards.