TECHNOLOGY

A GREENHOUSE GAS ACCOUNTING FRAMEWORK FOR CARBON CAPTURE AND STORAGE PROJECTS

CENTER FOR CLIMATE AND ENERGY SOLUTIONS

by

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FOREWORD Eileen Claussen, President, Center for Climate and Energy Solutions

Meeting the global challenge to reduce greenhouse gas (GHG) emissions and avoid dangerous climate impacts requires deploying a portfolio of emission reduction technologies.

We must both commit to broad and deep efficiencies in the way our societies' consume energy and to significant increases in power supplies from low carbon energy sources. At the same time, it is important to recognize that the scale of the challenge to reduce global emissions is massive, and that it will take decades for new and advanced low and zero emissions technologies to sufficiently mature and dominate the world's primary energy supply.

Recognizing that the use of fossil fuels—including coal—will continue to maintain a central role in powering the global economy for at least the next several decades, the portfolio of solutions to achieve the necessary GHG emissions reductions must include carbon capture and storage (CCS). Geologic storage of carbon dioxide (CO_2) emissions currently represents the only option to substantially address the GHG emissions from fossil fuel-fired power plants and large industrial facilities.

Our CCS Accounting Framework provides quantification methodologies to document the emissions reductions from CCS projects according to international best practices. It is intended to help project developers and program administrators identify and develop policies to recognize and reward investments that prevent CO_2 from entering the atmosphere by capturing and safely and permanently storing it in deep geologic reservoirs.

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EXECUTIVE SUMMARY

The Greenhouse Gas Accounting Framework for Carbon Capture and Storage (CCS) Projects—CCS Accounting Framework—provides methods to calculate emissions reductions associated with capturing, transporting, and safely and permanently storing anthropogenic carbon dioxide (CO_2) in geologic formations. It aims for consistency with the principles and procedures from ISO 14064-2:2006. *Greenhouse gases—Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements*, which represents best practice guidance for the quantification of project-based GHG emission reductions.

Ultimately, the objective of the CCS Accounting Framework is to inform and facilitate the development of a common platform to account for greenhouse gas (GHG) emissions reductions due to capturing and geologically storing CO_2. It also contributes to the public discussion about the viability of CCS to serve as a feasible CO_2 mitigation solution.

CCS refers to a suite of technologies that, when effectively combined, prevent CO_2 from entering the atmosphere. The process involves capturing and compressing CO_2 from power plants and other industrial facilities, transporting it to suitable storage sites, and injecting it into geologic formations for secure and permanent sequestration.

The emissions accounting procedures in the CCS Accounting Framework apply to multiple CO_2 source types, including electric power plants—equipped with pre-combustion, postcombustion, or oxy-fired technologies—and industrial facilities (for example, natural gas production, fertilizer manufacturing, and ethanol production). For CO_2 transport, the calculation methodology in this document applies only to pipelines because while other methods of transport, (e.g., truck transport) are possible, they are typically not considered viable options for large-scale CCS endeavors. With respect to the geological storage of CO_2, the CCS Accounting Framework applies to saline aquifers, depleted oil and gas fields, and enhanced oil and gas recovery sites.

The CCS Accounting Framework provides a comprehensive set of GHG accounting procedures within a single methodology. The quantification approach includes equations to calculate emissions reductions by comparing baseline emissions to project emissions—the difference between the two represents the GHG reductions due to capturing and sequestering CO_2, which would have otherwise entered the atmosphere.

GHG reductions from CCS project	=	**Baseline emissions**	-	**Project emissions**

- Baseline emissions represent the GHG emissions that would have entered the atmosphere if not for the CCS project.
- Project emissions are actual GHG emissions from CO_2 capture sites, transport pipelines, and storage sites.

The quantification approach to determine baseline emissions presents two baseline options: 1) "Projection-based" and 2) "Standards-based." In both cases, the calculation method uses data from the actual CCS project to derive baseline emissions.

Determining project emissions involves measuring CO_2 captured and stored by the project and deducting CO_2 emitted during capture, compression, transport, injection, and storage (and recycling of CO_2 if applicable).

The procedure to determine project emissions also accounts for GHG emissions from energy inputs required to operate CO_2 capture, compression, transport, injection and storage equipment. Energy inputs include "direct emissions" from fossil fuel use (Scope 1 emissions) and, in case required by a program authority, "indirect emissions" from purchased and consumed electricity, steam, and heat (Scope 2 emissions).

CCS project monitoring covers large above ground industrial complexes and expansive subterranean geologic formations. In terms of emissions accounting, monitoring CO_2 capture and transport involves well known technologies and practices, established over many years for compliance with federal and state permitting programs. Therefore, the monitoring program would follow generally accepted methods and should correspond with GHG monitoring requirements associated with the relevant subparts of EPA's Greenhouse Gas Reporting Program (GHGRP) and other state-level programs.

On the other hand, monitoring geologic storage sites for the purpose of verifying the safe and permanent sequestration CO_2 from the atmosphere is a relatively recent activity that may involve new techniques and technologies. While there exists no standard method or generally accepted approach to monitor CO_2 storage in deep rock formations, project developers will benefit from monitoring practices deployed over the past 35 years in CO_2 enhanced oil and gas recovery operations. Thus, the CCS Accounting Framework does not prescribe an approach to monitor CO_2 sequestration, as geologic storage sites will vary from site to site and demand unique, fit-for-purpose monitoring plans. This approach is consistent with the monitoring, reporting and verification (MRV) procedures for geologic sequestration from subpart RR to EPA's Greenhouse Gas Reporting Program, which overlays the monitoring requirements associated with the Underground Injection Control Program.

INTRODUCTION

The Greenhouse Gas (GHG) Accounting Framework for Carbon Capture and Storage (CCS) Projects—CCS Accounting Framework—provides methods to calculate emissions reductions associated with capturing, transporting, and safely and permanently storing carbon dioxide (CO_2) in geologic formations. It also includes options for defining baselines, delineating project assessment boundaries, and monitoring project performance.

CCS refers to a suite of technologies that, when effectively combined, prevents CO_2 from entering the atmosphere. The process involves capturing and compressing CO_2 from power plants and other industrial facilities, transporting it to suitable storage sites, and injecting it into appropriate geologic formations for secure and permanent sequestration.

1. GOALS AND OBJECTIVES

Ultimately, the objective of the CCS Accounting Framework is to inform and facilitate the development of a common platform to account for CO_2 emissions reductions associated with capturing and geologically storing CO_2.

The methods to determine baselines, delineate boundaries, quantify emissions, and monitor project performance represent a first-attempt to provide an integrated emissions accounting methodology for a range of CCS projects types, consistent with the International Standards Organization's (ISO) GHG accounting standard, 14064-2:2006: *Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements.*

By presenting approaches to calculate the emissions reductions from CCS projects according to commonly accepted GHG accounting principles and criteria (see Section 6), the CCS Accounting Framework aims to contribute to the public discussion about the viability of CCS to serve as a feasible CO_2 mitigation solution. This document could also assist regulators evaluate options to incorporate CCS into energy and climate-related programs within their jurisdiction. Furthermore, it could inform assessments by CCS project developers and investors of project development risks and opportunities.

BOX 1: Policy-Neutral GHG Accounting Guidance

The CCS Accounting Framework does not recommend specific policy mechanisms to reward or incentivize CCS. This document is intentionally designed to be "policy neutral"—i.e., to be useful for multiple types of policy options. Therefore, the methodology could assist with the quantification of emissions reductions for tax credits, bonus allowances in a cap and tradetype of program, offsets credits (for compliance or voluntary commitments), or other potential mechanisms.

GHG programs that use the emissions accounting methods in this document will need to provide additional information on program-specific rules that compliment the technical guidance to calculate emissions reductions. For example, program authorities would augment the GHG quantification procedures with rules on long-term liability for reversals of emissions reductions, ownership of emissions reductions, "additionality" criteria, CO_2 storage standards for "permanence," and determination of baselines, among other matters. Appendix A provides a discussion of additional policy-related issues that policymakers may need to address, depending on the nature of the program or policy.

2. DOCUMENT ORGANIZATION

The CCS Accounting Framework is organized into three parts:

- The first part (sections one through six) provides an overview of the CCS Accounting Framework's goals and objectives, scope and applicability, the emissions reduction and project monitoring approaches, and discusses how this document relates to commonly accepted GHG accounting principles and project criteria.

- Sections seven through nine in the second part present options for selecting baselines, considerations for delineating boundaries to conduct a GHG assessment, and methods to quantify GHG emissions reductions from CCS projects through a series of calculation procedures.
- The last part of the document (sections ten through twelve) includes project monitoring guidance to collect and organize data to quantify GHG reductions from CCS projects; it also provides references for monitoring effective containment of injected CO_2 in geologic reservoirs.

Appendix A discusses four policy-related issues that could impact rules and procedures to quantify the GHG reductions from CCS projects. Appendix B provides an overview of the U.S. Environmental Protection Agency's (EPA) Underground Injection Control Program and Greenhouse Gas Reporting Program. Appendix C includes summary tables of baseline and project calculation methods. Appendix D includes supplemental emissions quantification methods.

3. SCOPE AND APPLICABILITY

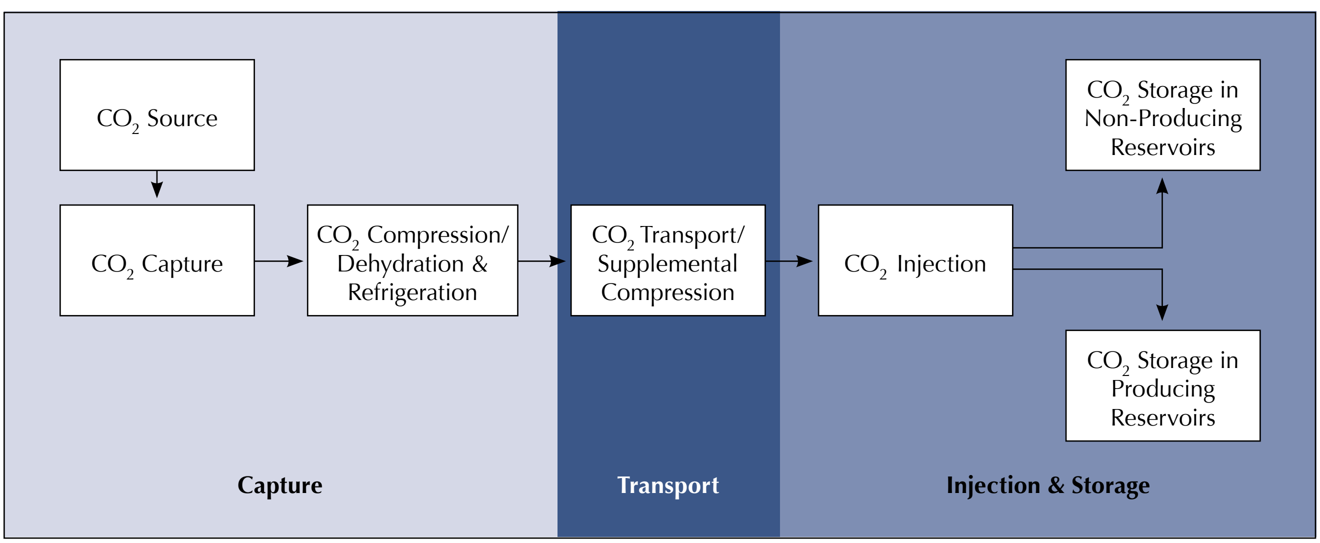
The scope of the CCS Accounting Framework includes CO_2 capture, as well as pipeline transport and CO_2 injection and geologic storage. Correspondingly, it provides methods to quantify GHG emissions from the anthropogenic source of CO_2 to the underground CO_2 storage reservoir.

Figure 1 provides a basic schematic of a CCS project illustrating the scope of the CCS Accounting Framework.

With respect to the capture of CO_2, the procedures in the CCS Accounting Framework apply to multiple CO_2 source types, including electric power plants—equipped with pre-combustion, post-combustion, or oxy-fired technologies—and industrial facilities (for example, natural gas production, fertilizer manufacturing, and ethanol production). For transporting CO_2, there are essentially two options: trucking it from the source to the storage field or moving the CO_2 in a pipeline. The calculation methodology in this document applies only to pipelines because while other methods of transport, (e.g., truck transport) are possible, they are typically not considered economically viable for large-scale CCS endeavors. In considering the geological storage of CO_2, the CCS Accounting Framework could apply to saline aquifers, depleted oil and gas fields, and enhanced oil and gas recovery sites.

The equations in Section 9 to calculate emissions reductions could apply to multiple types of project configurations located within the United States as well as other regions. However, the CCS Accounting Framework often uses the U.S. EPA as a point of reference for the quantification procedures and project monitoring guidance. Therefore, users of this methodology should take care to apply it in a manner consistent with the rules and regulations within the appropriate jurisdiction.

FIGURE 1: Basic CCS Project Schematic



BOX 2: CCS Project Developer and Program Authority

Project developer. The term "project developer" is used throughout the document to generally represent the entity implementing the CCS project and electing to take responsibility to meet certain measurement and monitoring requirements. For ease of use, this document does not distinguish between the different entities involved in the multiple components of a CCS project—CO_2 capture, transport, or storage site operators are collectively referred to as the "project developer."

Program authority. The term "program authority" refers to an agency or authorized organization responsible for a state or federal GHG program or an organization that runs a voluntary GHG inventory or offset registry. If a program authority chooses to recognize and reward the CO_2 reductions associated with CCS projects, it could incorporate the approaches in the CCS Accounting Framework into its protocols and augment it with program-specific rules and requirements.

4. OVERVIEW OF THE GHG REDUCTION CALCULATION APPROACH

The CCS Accounting Framework provides GHG accounting procedures for CCS projects. The quantification approach includes equations to calculate emissions reductions by comparing baseline emissions to project emissions—the difference between the two represents the GHG reductions due to capturing and sequestering CO_2, which would have otherwise entered the atmosphere if not for the CCS project.

GHG reductions from CCS project	=	**Baseline emissions**	-	**Project emissions**

- Baseline emissions represent the GHG emissions that would have entered the atmosphere if not for the CCS project.
- Project emissions are actual emissions from CO_2 capture sites, transport pipelines, and storage sites.

The emissions quantification approach to determine baseline emissions is structured according to the following two options: 1) "Projection-based" and 2) "Standards-based." In both cases, the calculation method uses data from the actual CCS project to derive baseline emissions.

Calculating project emissions involves measuring CO_2 captured and stored by the project and deducting CO_2 emitted during capture, compression, transport, injection, and storage (and recycling of CO_2 if applicable). The procedure to determine project emissions also accounts for GHG emissions from energy inputs required to operate CO_2 capture, compression, transport, injection and storage equipment. Energy inputs include "direct emissions" from fossil fuel use (Scope 1 emissions) and, in case required by a program authority, "indirect emissions" from purchased and consumed electricity, steam, and heat (Scope 2 emissions).[1]

5. OVERVIEW OF PROJECT MONITORING

CCS project monitoring applies to large above ground industrial complexes and expansive subterranean geologic formations.

Monitoring CO_2 capture and transport for emissions accounting purposes involves well known technologies and practices, established over many years for compliance with federal and state permitting programs. Therefore, the monitoring program would follow generally accepted methods and correspond with GHG monitoring requirements associated with the relevant subparts of EPA's Greenhouse Gas Reporting Program (GHGRP)[2] and other state-level programs, as necessary.

On the other hand, monitoring geologic storage sites to verify the safe and permanent sequestration of CO_2 from the atmosphere is a relatively recent activity that could make use of existing technologies in new ways. Furthermore, there exists no standard method or generally accepted approach to monitor CO_2 storage in subsurface formations, applicable to all types of CO_2 storage operations. However, developing CO_2 storage monitoring plans will benefit from monitoring practices deployed for over 35 years for CO_2 enhanced oil and gas recovery, as well as waste management operations that involve injections into the subsurface.

Since the primary objective of this document is to present emissions accounting approaches, the project monitoring guidance in Section 11 includes methods to collect data to execute equations to determine baseline emissions and project emissions, in correspondence with the GHG quantification procedures in Section 9.

Thus, with respect to monitoring geologic storage reservoirs to confirm that injected CO_2 remains sequestered from the atmosphere, Section 12 provides a list of resources on CO_2 storage monitoring technologies and techniques to inform project developers' choices about deploying systems across project phases. This approach reflects the reality that unique, site-specific conditions for each reservoir preclude the development of prescriptive monitoring guidance. Rather than impose a one-size-fits-all monitoring regime for CO_2 storage sites, the CCS Accounting Framework directs project developers to use best practices to design a site-specific CO_2 storage monitoring plan, which would be incorporated into an overall monitoring plan for the CCS project. The development of reservoir-specific monitoring plans, in which project developers create strategies to detect and quantify leakage of CO_2 out of the geologic storage complex to the atmosphere, is included in the MRV procedures for geologic sequestration from subpart RR to EPA's GHGRP, which overlays the monitoring requirements associated with the Underground Injection Control (UIC) Program.[3] Appendix B provides a description of the EPA's UIC program and GHGRP.

BOX 3: Data Access

The quantification methods and monitoring parameters described in the CCS Accounting Framework presume CCS project developers have full access to data. However, in most cases, a single entity will not own and operate the CO_2 capture, transport, and storage equipment and sites. As such, proprietary information challenges may exist. When these challenges arise, cooperation among the different entities that own and/or operate the capture, transport and storage components will be required. Table 2 in Section 11 provides data collection information on the variables to monitor—i.e., "monitoring parameters"—for project developers to carry out the emissions quantification equations.

6. PRINCIPLES OF GHG REPORTING AND CRITERIA FOR PROJECT ACCOUNTING

As stated above, the CCS Accounting Framework aims for consistency with the principles and procedures from ISO 14064-2, which represents best practice guidance for the quantification of project-based GHG emission reductions.[4]

The emissions quantification procedures reflect generally accepted accounting and reporting principles and criteria, such that reported information should represent a faithful, true, and fair assessment of the impact of the CCS project. The following principles serve as the foundation for identifying GHG sources and sinks and quantifying emissions. The CCS Accounting Framework is designed to satisfy these principles to help assure the credibility of calculated GHG reductions.

- Relevance—Select GHG sources, sinks, reservoirs, data and methodologies appropriate to the scope of the project and needs of the intended user.
- Completeness—Include all relevant GHG emissions, removals, and storage.
- Consistency—Enable meaningful comparisons of GHG-related information.
- Accuracy—Reduce bias and uncertainties as far as practical.
- Transparency—Disclose sufficient and appropriate GHG-related information to allow intended users to make decisions with reasonable confidence.
- Conservatism—Where questions arise regarding uncertain parameters or data sources, or where further analysis is not cost-effective, choose a conservative approach that is likely to underestimate rather than overestimate GHG reductions.

In addition to the overarching principles applicable to all GHG accounting and reporting activities, projects that quantify emissions reductions must also meet defined GHG project criteria. Specifically, projects wishing to quantify emission reductions may have an obligation to satisfy certain project accounting criteria to substantiate the veracity of their GHG reduction claims. For example, California's Global Warming Solutions Act of 2006, Assembly Bill 32 (AB32–Núñez, Chapter 488, Statutes of 2006) states that the California Air Resources Board (the regulatory agency responsible for implementing AB32) should only approve GHG reduction projects that are quantifiable, additional, permanent, verifiable, and enforceable.[5] Table 1 describes these criteria.

TABLE 1: GHG Project Accounting Criteria

CRITERION	DEFINITION
Real/Quantifiable	Reductions represent an actual, measurable/calculable decrease in GHG emissions due to the project, which would have otherwise entered the atmosphere. See Section 9 for a presentation of calculation procedures to quantify GHG reductions from CCS projects.
Additional	Reductions represent a decrease in GHG emissions incremental to what would have happened if not for the project—i.e., beyond business as usual. Appendix A provides a discussion of additionality.
Permanent	GHG reductions from the project are not reversible—i.e., CO_2 remains sequestered at a level and duration that achieves a clear atmospheric benefit, as defined by a program authority. Appendix A provides a discussion about permanence and reversals in GHG reductions.
Verifiable	Confirmation that the GHG reductions from the project are consistent with the methodologies provided by the appropriate program authority.
Enforceable	Identification of clear roles and responsibilities among project participants and between project participants and a program authority to hold responsible parties accountable for not meeting commitments to program authorities. See Appendix A for a discussion about ownership of emissions reductions.

QUANTIFYING GHG EMISSIONS REDUCTIONS

The purpose of the following sections is to present GHG calculation methods to quantify emissions reductions from CCS projects. The quantification approach involves comparing derived baseline emissions to actual project emissions. The difference between the two represents the emission reductions from the CCS project.

Section 7 provides information on identifying and selecting a baseline (against which to compare actual emissions from the project). Section 8 illustrates boundaries for the quantification exercise. Section 9 presents methods to calculate baseline and project emissions within the quantification boundary.

7. BASELINES

In terms of GHG project accounting, a baseline is a hypothetical situation that represents the condition most likely to occur in the absence of the GHG emission reduction project. It serves as a reference case against which to quantitatively compare the GHG emissions associated with the project and derive net emission reductions.[6]

The CCS Accounting Framework presents two baseline options, referred to as "Projection-based" and "Standards-based."

7.1. Baseline Options for CCS Projects

A project developer would select the baseline that applies to its project, and then follow the matching calculation procedure. The choice of baseline dictates the equations applied, as provided in Section 9.1.1 and 9.1.2:

Projection-based baseline → Equation 2

Standards-based baseline → Equation 3

Projection-based. This option represents a baseline that would correspond with the project's actual CO_2 capture site, absent the capture and compression system located at the CO_2 source. For example, if the CCS project includes a coal electricity generator with post-combustion capture, a Projection-based baseline would be the coal plant without CO_2 capture; similarly, if the CCS project captures CO_2 from acid-gas removal associated with natural gas production, a Projection-based baseline would be the natural gas production facility with acid gas removal but with CO_2 vented to the atmosphere.

According to the calculation approach, project developers determine Projection-based baseline emissions according to actual measured quantities of CO_2 captured from the project, which would have been vented to the atmosphere had the CCS project not been implemented, minus the incremental CO_2 generated at the capture site due to CO_2 capture equipment. The calculation uses data collected from the CO_2 capture site to represent the quantity of emissions prevented from entering the atmosphere.

Standards-based. The Standards-based baseline is expressed in the form of a metric or "performance standard" (tCO_2e/unit of output). Depending on the circumstance, it could correspond with a similar or different technology than the CCS project's actual CO_2 capture site, but which fulfills the same purpose and function. For instance, if the CCS project includes a coal electricity generator with post-combustion capture, a Standards-based baseline could be represented by a coal-fired or natural gas-fired power plant's emissions rate, expressed as tons CO_2/MWh. In this case, baseline emissions would be calculated by multiplying the actual MWhs delivered to the grid in the project condition (net MWh) times the emissions rate approved by the program authority.

A Standards-based baseline is sector specific, at minimum, to ensure reasonable accuracy, and it could have a different emissions profile than the technology used at the CO_2 capture site.

7.2. Baseline Considerations for Retrofit and New-Build CCS Projects

Depending on the situation, either the Projection-based or Standards-based baseline could apply to projects that capture CO_2 at power generation or other industrial facilities, and inject CO_2 at various types of storage sites.

Retrofit CCS Projects. Given the limited number of climate change policies that require GHG emissions reductions from facilities in the U.S., the baseline for most retrofit projects would involve the continued operation of the existing CO_2 source facility, but without carbon capture and storage—such that produced CO_2 is vented to the atmosphere. This corresponds with the Projection-based baseline.

However, if the retrofit involves a major overhaul of technologies, then applying a Projection-based baseline might not be the most reasonable approach. Instead, it may be more appropriate to characterize the baseline in terms of the emissions rate associated with a specific technology, often called a performance standard.

A Standards-based baseline could also apply to retrofit projects if a law or regulation affects CO_2 emissions production at the capture site, such as a mandate to meet a minimum GHG emission performance standard.

New Build CCS Projects. The baseline for new facilities will often correspond with the common practice in the region and the most economic option available to the project developer. As with retrofit projects, provided that there are no regulations in place that require the use of certain technologies, mandate the installation of CCS, or prevent the implementation of the most common technology option, the baseline for a new build facility would likely be the operation of the project configuration without the CCS capture component that vents all of the produced CO_2 to the atmosphere—a Projection-based baseline.

However, multiple economic and market, social, environmental, and political considerations exist that impact technology choices and configurations. Thus, project developers could decide that an emissions performance standard best represents its project circumstances—as opposed to as a "continuation of current practices"—and program authorities could similarly decide that a Standards-based baseline is most suitable for its program.

8. GHG ASSESSMENT BOUNDARIES

The GHG assessment boundary defines the scope of the emissions quantification methodology. It demarcates the sources included in the project and baseline emissions calculation (as presented in Section 9).

Recognizing the variety and complexity of project configurations where CO_2 may be captured and compressed, transported and injected into different types of reservoirs, Figure 2 provides a general illustration of project boundaries to account for the full range of potential CCS project types.

Leakage. An important consideration when determining the project boundary is "leakage," which refers to unintended increases in emissions due to the project activity—usually occurring outside the physical project boundary. An objective in defining boundaries is to minimize or avoid leakage.

In this CCS Accounting Framework, the project boundary is intentionally drawn broadly to avoid unaccounted emissions associated with capturing and storing CO_2. Specifically it covers the full CCS value chain, including emissions from CO_2 recovery and re-injection operations at enhanced oil and gas recovery sites.

Program authorities will ultimately decide the scope of the GHG assessment boundary and the extent to which it includes emission sources upstream of the CO_2 capture site and downstream of CO_2 storage.

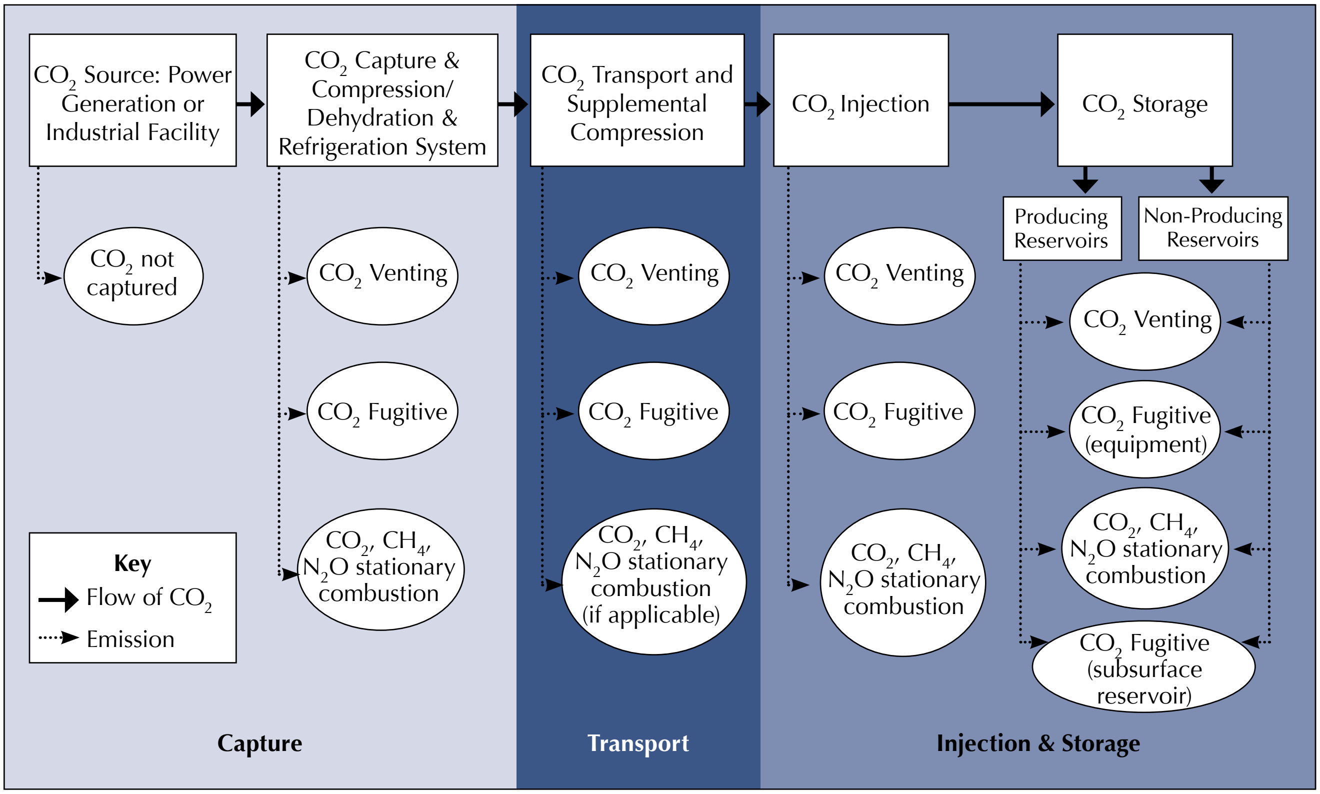
Primary Process. The installation of CO_2 capture may impact one or more emissions sources at a facility, but may also leave unaffected other sources. Therefore, to ensure the emissions reduction calculation approach reflects the relevant change in emissions due to the project, the baseline and project boundaries should focus on incorporating GHG sources affected by the project—i.e., the change in emissions due to capturing CO_2. For example, a boundary for CO_2 capture at a hydrogen production unit within a refinery would encompass systems associated with the hydrogen production process but might exclude downstream units that use the hydrogen (e.g., hydro-treating units) or other upstream processes unaffected by the CO_2 capture system.

The specific power generation or industrial process (e.g., natural gas processing, hydrogen production, steelmaking) creating the captured CO_2 is referred to in this document as the "primary process." If CO_2 is captured from more than one process, then project developers should combine them within the boundary that encompasses the capture site.

9. GHG EMISSIONS QUANTIFICATION METHODOLOGY

Overall GHG emission reductions from the CCS project equal Baseline Emissions (BE) minus Project Emissions (PE), as shown in Equation 1. The calculation procedures

FIGURE 2: CCS Project Boundary



for the baseline emissions and project emissions are presented in the following sections.[7]

9.1. Calculation Procedure for Baseline Emissions

The CCS Accounting Framework provides two approaches to calculate baseline CO_2 emissions—Projection-based and Standards-based. To be conservative, the procedures do not calculate methane (CH_4) or nitrous oxide (N_2O) emissions.

Functional Equivalence. The implementation of CO_2 capture infrastructure may result in changes to energy consumption and/or product output, and impact the quantity of GHG emissions produced at the capture site. Since the calculation of baseline emissions involves collecting and using actual project data from the capture site, a project developer could inaccurately quantify emissions reductions from the CCS project if it does not appropriately maintain "functional equivalence" between the baseline and project and adjust applied data, as necessary.

EQUATION 1: Total Annual GHG Reductions

$$\textbf{GHG Reductions}_{y} = \textbf{BE}_{y} - \textbf{PE}_{y}$$

Where,

GHG Reductions $_y$	=	Total annual GHG reductions from the CCS project (tCO_2e/yr).
BE $_y$	=	Baseline CO_2e Emissions in each year (tCO_2e/yr).
PE $_y$	=	Project CO_2e Emissions in each year (tCO_2e/yr).

For example, in some project configurations, incremental emissions associated with running the capture system could yield an overall increase in CO_2 production and result in a larger volume of CO_2 captured and processed, relative to what the "primary process" would have emitted in the baseline. A power plant retrofitted with post-combustion CO_2 capture, for instance, that maintains (net) electricity production levels by burning additional coal to produce steam and electricity to power the capture system would increase overall CO_2 production. In this case, using actual measured CO_2 production values from the project to derive baseline emissions could overestimate baseline emissions.

Alternatively, a similar power plant could burn an equivalent amount of coal as the pre-retrofit plant and correspondingly produce the same amount of CO_2 as the baseline. This might occur if steam from the coal-fired boiler is directed toward the capture system to regenerate the CO_2 absorber rather than the power cycle. Therefore, while the capture system would not cause an increase in total CO_2 production, it could lead to the generation of less electricity. In this case, if a project developer uses actual electricity production data to derive baseline emissions, it could underestimate baseline emissions.

In other project configurations, some or all of the incremental energy needed to meet the demands of the CO_2 capture system could be provided through separately powered systems, including process heaters, boilers, engines, turbines or other fossil fuel-fired equipment. In this case, the corresponding CO_2 emissions streams would likely be separate from the captured CO_2 from the primary process.

Project developers should adjust actual project data relied upon to quantify baseline emissions, if necessary. This is done to ensure that the quantified emissions reductions appropriately represent the impact of the CCS project and that the comparison between project and baseline emissions maintains "functional equivalence."

9.1.1. Calculation Procedure for Projection-Based Baseline

The Projection-based baseline uses actual GHG emissions from the project to represent what would have occurred in the absence of CCS.

The procedure involves multiplying the amount of actual CO_2 produced by the primary process, (which project developers measure immediately downstream of the primary process) by an "adjustment factor" that accounts for incremental changes in CO_2 produced by the capture equipment and included in the measured CO_2 stream. As discussed above, the adjustment factor is a part of the equation to maintain functional equivalence between the baseline and project. As approved by a

EQUATION 2: Total Annual Projection-based Baseline GHG Emissions

$$BE_{\text{Projection-Based, y}} = (Vol._{\text{Gas Produced, y}} \times \%CO_2 \times \rho CO_2) \times AF$$

Where,

$BE_{\text{Projection-Based, y}}$	=	Baseline emissions for a CCS project where the baseline scenario is defined using a Projection-based approach in each year (tCO_2/yr).
$Vol._{\text{Gas Produced, y}}$	=	Volume of actual CO_2 gas produced from the primary process, metered at a point immediately downstream of the primary process, at standard conditions, in each year (m^3 gas/yr).
$\%CO_2$	=	% CO_2 in the gas stream, monitored immediately downstream of the primary process, in each year (% volume).
ρCO_2	=	Density of CO_2 at standard conditions (metric ton/m^3).
AF	=	Baseline "adjustment factor" to account for incremental CO_2 from the capture equipment and included in the measured CO_2 stream (unitless).[8] Determined on a project-by-project basis. If the CO_2 capture system is separately run and operated and the corresponding CO_2 emissions are not included in the "$Vol._{\text{Gas Produced, y}}$ CO_2" term, then insert 1 (one) for this term.

program authority, project developers would determine the appropriate way to correct measured CO_2 emissions on a project-by-project basis.

As provided in Equation 2, for combustion processes the mass of CO_2 could be determined from flue gas volume and composition measurements. Table 2 in Section 11 includes the monitoring parameters.

9.1.2 Calculation Procedure for Standards-based Baseline

The Standards-based baseline is calculated by multiplying an emissions intensity metric or "performance standard," expressed as (tCO_2e/unit of output), by the actual output of the project's primary process (e.g., MWh for power generation, MMscf processed for natural gas production), as provided in Equation 3.

Program authorities will ultimately approve the level of CO_2 production for the numerator of the metric, based on the type of facility creating the captured CO_2, and, for the denominator, define the "output" of the primary process to maintain functional equivalence between baseline emissions and project emissions. Procedures for collecting data from the actual project to determine the "output" value used to calculate baseline emissions should be set to ensure that the quantified emissions reductions appropriately represents the impact of the CCS project.

For example, regarding CCS projects that involve power generation, electricity may be used to operate the CO_2 compressors or other equipment associated with the capture system—reducing the amount of electricity delivered to the grid or sold to direct connected users, as compared to a facility without CO_2 capture. In this case, using gross electricity production as the "output" might be more appropriate then net electricity production.

Table 2 in Section 11 provides the monitoring parameters for the Standards-based baseline calculation.

EQUATION 3: Total Annual Standards-based Baseline Emissions

$$BE_{\text{Standards-based}} = BE_{\text{performance standard}} * Output_y$$

Where,

$BE_{\text{Standards-based}}$	=	Standards-based baseline emissions for a CCS project in year y (tCO_2/yr).
$BE_{\text{performance standard}}$	=	Baseline emissions intensity metric, specific to the type of primary process that creates the CO_2 for capture, as prescribed by the relevant program authority (tCO_{2e}/unit of output).
$Output_y$	=	Units of output from the CO_2 capture facility (e.g., MWh) in the project condition in year y (units of output).

EQUATION 4: Total Project Emissions

$$PE_y = PE_{\text{Capture, y}} + PE_{\text{Transport, y}} + PE_{\text{Storage-NP, y}} + PE_{\text{Storage-P, y}}$$

Where,

PE_y	=	Project emissions from CCS project in year y (tCO_2e/yr).
$PE_{\text{Capture, y}}$	=	Project emissions from CO_2 capture and compression in year y (tCO_2e/yr). Refer to Section 9.2.1.
$PE_{\text{Transport, y}}$	=	Project emissions from CO_2 transport in year y (tCO_2e/yr). Refer to Section 9.2.2.
$PE_{\text{Storage-NP, y}}$	=	Project emissions from CO_2 injection and storage in non-producing formations in year y (tCO_2e/yr). Refer to Section 9.2.3 and 9.2.5.
$PE_{\text{Storage-P, y}}$	=	Project emissions from CO_2 injection and storage in producing formations in year y (tCO_2e/yr). Refer to Sections 9.2.4 and 9.2.5.

9.2 Calculation Procedure for Project Emissions

CCS project emissions equal the sum of CO_2e emissions from CO_2 capture, transport, and storage in producing or non-producing formations, as shown in Equation 4.[9]

9.2.1 Calculation Procedures for CO_2 Capture

The calculation procedure for the CO_2 capture process reflects the delineation of the boundary of the capture site, which encompasses the source of CO_2, as well as auxiliary equipment associated with the CO_2 capture and compression systems. In many cases, the primary process that generates the CO_2 is part of a large industrial complex (e.g., a refinery, bitumen upgrader, chemical plant, gas processing plant, etc.) with many processes unaffected by or independent of the CO_2 capture activities. As discussed above, only those processes directly impacted by the CO_2 capture process are included in the quantification assessment. The boundary of the capture site extends to the point at which CO_2 enters the pipeline, typically the point at which CO_2 is transferred to the CO_2 pipeline operator.

Equation 5 outlines the methods for calculating emissions from the capture segment of CCS projects. This equation is applicable to pre-combustion capture, post-combustion capture, oxy-fuel capture and CO_2 capture at industrial sites.

Consistent with the objective to provide a complete assessment of the impact of the CCS project, this quantification method accounts for all non-captured emissions from the primary process that enter the atmosphere. For example, a post-combustion system might capture 90 percent of CO_2 created by a power production facility; thus, the ten percent not-captured is incorporated into the quantification approach to provide a comprehensive representation of the emissions profile of the capture segment of the CCS project.

The calculation approach collectively refers to CO_2 from the primary process emitted to the atmosphere through vent stacks and fugitive releases from equipment at the capture and compression systems as "non-captured CO_2."

Vented and fugitive emissions from capturing and compressing CO_2 include both intentional and unintentional releases. CO_2 may be vented through dedicated vent stacks during normal operation, process upsets, or shutdowns. Fugitive emissions may arise from leakage of CO_2 from equipment such as flanges, valves and flow meters.

Equations 5.1, 5.1.A, 5.1.B, and 5.1.C account for the portion of CO_2 generated from the primary process that is not captured but emitted to the atmosphere. Project developers calculate emissions by subtracting CO_2 transferred to the transport segment of the CCS project from total CO_2, CH_4, and N_2O produced from the primary process. Table 2 in Section 11 provides the monitoring parameters to calculate total annual CO_2 produced from the primary process and transferred to the CO_2 pipeline; it also provides the monitoring parameters necessary for calculating the CH_4 and N_2O emissions from the primary process.

EQUATION 5.0: Total Annual Project Emissions from the Capture Segment

$$PE_{\text{Capture, y}} = PE_{\text{C-PP, y}} + PE_{\text{C-Comb, y}} + PE_{\text{C-Indirect Energy, y}}$$

Where,

$PE_{\text{Capture, y}}$	=	Project emissions from CO_2 capture and compression in each year (tCO_2e/yr).
$PE_{\text{PP, y}}$	=	Project emissions from the primary process (physical CO_2 emissions) that have not been captured by the CO_2 capture process, including project emissions from venting of CO_2 during capture and compression, and project emissions from fugitive releases of CO_2 during capture and compression in each year (tCO_2/yr). Refer to Equation 5.1.
$PE_{\text{Comb, y}}$	=	Project emissions from on-site use of fossil fuels to operate support equipment for the CO_2 capture and compression facilities in each year (tCO_2e/yr). Refer to Equation 5.2.
$PE_{\text{Indirect Energy, y}}$	=	Project emissions from purchased electricity and thermal energy used to operate the CO_2 capture and compression systems in each year (tCO_2e/yr), if required by a program authority. Refer to Equation 5.3.

EQUATION 5.1: Non-Captured CO_2e Emissions from the Primary Process at the Capture Site

$$PE_{C\text{-}PP,\,y} = CO_2\ Produced_{PP,\,y} + CO_2e\ Produced_{PP,\,y} - CO_2\ Transferred_{PP,\,y}$$

Where,

$PE_{C\text{-}PP,\,y}$	=	Project emissions from the primary process that have not been captured by the CO_2 capture process, including project emissions from venting of CO_2 during capture and compression, and project emissions from fugitive releases of CO_2 during capture and compression in each year (tCO_2/yr).
CO_2 Produced $_{PP,\,y}$	=	Total CO_2 produced from the primary process in each year (tCO_2/yr), where the volume of gas is measured directly downstream of the primary process. Refer to Equation 5.1.A.[10]
CO_2e Produced $_{PP,\,y}$	=	Total CH_4 and N_2O produced from the primary process in each year (tCO_2/yr). Only applicable to CO_2 capture projects that use combustion to produce CO_2 for capture. Refer to Equation 5.1.B.
CO_2 Transferred $_{PP,\,y}$	=	CO_2 captured and transferred to the CO_2 pipeline, metered at the point of transfer with the pipeline in each year (tCO_2/yr). Refer to Equation 5.1.C.

EQUATION 5.1.A: Primary Process CO_2 Emissions*

$$CO_2\ Produced_{PP,\,y} = (Vol._{Gas\ Produced,\,y} \times \%CO_2 \times \rho CO_2)$$

Where,

CO_2 Produced $_{PP,\,y}$	=	Total CO_2 produced from the primary process in year each (tCO_2/yr).
Vol. $_{Gas\ Produced,\,y}$	=	Total volume of CO_2 gas produced from the primary process, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in each year (m^3 gas/yr).
$\%CO_2$	=	% CO_2 in the gas stream, measured immediately downstream of the primary process, at standard conditions, each year (% volume).
ρCO_2	=	Density of CO_2 at standard conditions (metric ton/m^3).

* See Appendix D for a fuel-based method to calculate emissions from stationary combustion projects which occur during the primary process where direct measurement of CO_2 is not possible.

EQUATION 5.1.B: Primary Process CH_4 and N_2O Emissions*

$$CO_2e\ Produced_{PP,\,y} = \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times GWP_{CH4} + \sum(Fuel_i \times EF\ N_2O_{Fuel\ i}) \times GWP_{N2O}$$

Where,

CO_2e Produced $_{PP,\,y}$	=	Gross amount of CH_4 and N_2O produced from the primary process in each year (tCO_2/yr).
Fuel $_i$	=	Total volume or mass of fuel, by fuel type i, input into the primary process in year each (e.g., m^3 or kg).
EF CH4 $_{Fuel\ i}$	=	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
EF N_2O $_{Fuel\ i}$	=	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/kg of fuel).
GWP_{CH4}	=	100 year Global Warming Potential of CH_4 = 21.
GWP_{N2O}	=	Global Warming Potential of N_2O = 310.

* Applicable to CO_2 capture projects which combust fossil fuels in the primary process.

EQUATION 5.1.C: CO_2 Captured and Input into CO_2 Transport Pipeline

$$CO_2\ Transferred_{,y} = Vol._{Gas\ Transferred,\ y} \times \%CO_2 \times \rho CO_2$$

Where,

CO_2 Transferred, $_y$	=	CO_2 captured and transferred to the CO_2 pipeline, metered at the point of transfer with the pipeline in each year (tCO_2/yr).
Vol. $_{Gas\ Transfered,\ y}$	=	Total volume of gas that has been captured and input into the pipeline, metered at the point of transfer with the pipeline in each year (m^3 CO_2/yr).
$\%CO_2$	=	% CO_2 in the gas stream measured at the input to the pipeline, at standard conditions (% volume).
ρCO_2	=	Density of CO_2 at standard conditions (metric ton/ m^3).

Emissions quantification at the CO_2 capture site also includes stationary combustion and electric-drive units to support the capture and compression processes, such as cogeneration units, boilers, heaters, engines, turbines. For example, the operation of a coal gasifier (primary process) with a pre-combustion absorption capture unit and electric-drive compression would require an air separation unit to generate pure oxygen for the gasification process, a fossil fuel steam generation unit to supply heat to regenerate the CO_2-rich absorbent, and grid electricity to drive the compressors and other auxiliary equipment. These emissions sources are included within the capture boundary to quantify the energy use associated with the CO_2 capture process.

Ultimately, GHG emissions from energy use will depend on the configuration of the capture and compression facilities and the types and quantities of fossil fuels combusted and electricity steam and heat consumed to provide energy for the capture and compression processes.

The following equation is used to quantify direct emissions from stationary fossil fuel-driven equipment used for CO_2 capture and compression.

EQUATION 5.2: Capture Site Emissions of CO_2, CH_4, and N_2O from Stationary Combustion Associated with Auxiliary Equipment

$$PE_{C\text{-}Comb,\ y} = \sum(Fuel_i \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_i \times EF\ CH4\ Fuel\ i) \times GWP_{CH4} + \sum(Fuel_i \times EF\ N_2O_{\ Fuel\ i}) \times GWP_{N2O}$$

Where,

$PE_{C\text{-}Comb,\ y}$	=	Project emissions from combustion of fossil fuels in stationary equipment used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
$Fuel_i$	=	Volume or mass of each type of fuel, by fuel type i, used to operate the CO_2 capture and compression facilities in each year (e.g., m^3/yr or kg/yr).
$EF\ CO_{2\ Fuel\ i}$	=	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4\ Fuel\ i}$	=	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
$EF\ N_2O_{\ Fuel\ i}$	=	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/ metric ton of fuel).
GWP_{CH4}	=	Global Warming Potential of CH_4 = 21.
GWP_{N2O}	=	Global Warming Potential of N_2O = 310.

For some CCS project configurations, operating the CO_2 capture and compression processes includes electricity or thermal energy purchased from third parties (e.g., electric utilities or off-site co-generation facilities). Specifically, electricity may be used to operate the compressors, dehydration units, refrigeration units, circulation pumps, fans, air separation units and a variety of other equipment. Purchased steam may be used for various purposes, including regeneration of the CO_2-rich absorbent used for a post-combustion capture configuration. Electricity may be sourced from direct connected generating facilities or from the regional electricity grid, while thermal energy may be sourced from nearby steam generators or cogeneration facilities. Thermal energy and electricity may be sourced from separate facilities or sourced from the same combined heat and power generation (cogeneration) facility.

If required by a program authority, indirect emissions associated with purchased energy inputs used to operate the CO_2 capture and compression processes may need to be quantified according to the following equations. Table 2 in Section 11 provides the monitoring parameters to calculate CO_2 emissions from purchased and consumed electricity, steam and heat.

EQUATION 5.3: CO_2 Emissions from Purchased and Consumed Electricity, Steam, and Heat

$$PE_{\text{C-Indirect Energy, y}} = PE_{\text{Elec, y}} + PE_{\text{Cogen, y}}$$

Where,

$PE_{\text{C-Indirect Energy, y}}$	=	Project emissions from purchased electricity and thermal energy used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
$PE_{\text{Elec, y}}$	=	Project emissions from grid electricity used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr). Refer to Equation 5.3.A.
$PE_{\text{Cogen, y}}$	=	Project emissions from thermal energy and/or electricity purchased from third party operated heat and/or power generation facilities used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr). Refer to Equation 5.3.B.

EQUATION 5.3.A: CO_2 Emissions from Purchased and Consumed Electricity

$$PE_{\text{Elec, y}} = \text{Electricity}_y \times EF_{\text{Electricity}}$$

Where,

$PE_{\text{Elec, y}}$	=	Project emissions from grid electricity used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
Electricity_y	=	Total metered grid electricity usage from equipment used to operate the CO_2 capture and compression facilities in each year (MWh).
$EF_{\text{Electricity}}$	=	Emission factor for electricity generation in the relevant region (tCO_2e/MWh).

EQUATION 5.3.B: CO_2, CH_4, N_2O Emissions from Purchased and Consumed Steam and/or Heat

$$PE_{Cogen,y} = \sum(Fuel_i \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times GWP_{CH4} + \sum(Fuel_i \times EF\ N_2O\ Fuel_i) \times GWP_{N2O}$$

Where,

$PE_{Cogen,y}$	=	Project emissions from thermal energy and/or electricity purchased from third party operated heat and/or power generation facilities used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
$Fuel_i$	=	Proportionate volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit to supply electricity or thermal energy to the CO_2 capture and compression facilities in each year (e.g., m^3/yr or kg/yr). Refer to Equation 5.3.C.
$EF\ CO_{2\ Fuel\ i}$	=	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4\ Fuel\ i}$	=	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/ kg of fuel).
$EF\ N_2O_{\ Fuel\ i}$	=	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/kg of fuel).
GWP_{CH4}	=	Global Warming Potential of CH_4 = 21.
GWP_{N2O}	=	Global Warming Potential of N_2O = 310.

EQUATION 5.3.C: Apportionment of Cogen Emissions by Product

$$Fuel_i = Total\ Fuel_{Cogen} \times [(Heat_{CCS\ Project} + Electricity_{CCS\ Project}) / (Heat_{Cogen} + Electricity_{Cogen})]$$

Where,

$Fuel_i$	=	Proportionate volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit to supply electricity or thermal energy to the CO_2 capture and compression facilities in each year (e.g., m^3/yr or metric tons/yr).[11]
$Total\ Fuel_{Cogen}$	=	Total volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit supplying electricity or thermal energy to the CO_2 capture and compression facilities in each year (e.g., m^3/yr or metric tons/yr).
$Heat_{CCS\ Project}$	=	Quantity of thermal energy purchased from the third party cogeneration unit to operate the CO_2 capture facilities (MWh/year).
$Electricity_{CCS\ Project}$	=	Quantity of electricity purchased from the third party cogeneration unit to operate the CO_2 capture and compression facilities (MWh/year).
$Heat_{Cogen}$	=	Total quantity of thermal energy generated by the third party cogeneration unit (MWh/year).
$Electricity_{Cogen}$	=	Total quantity of electricity generated by the third party cogeneration unit (MWh/year).

9.2.2 Calculation Procedures for CO_2 Transport

The GHG emission quantification approach for the transport segment of a CCS project includes the full pipeline system from the CO_2 delivery point at the capture site (downstream of the compressor) to the CO_2 delivery point at the storage site. The calculation methodology does not apply to CO_2 transported in containers (e.g., by truck, rail or ship).[12]

GHG emissions from CO_2 transport include CO_2 emissions from venting and fugitive releases as well as CO_2, CH_4 and N_2O emissions from stationary combustion and electricity use. Table 2 in Section 11 provides monitoring parameters to calculate emissions from CO_2 transport.

The following equation shows an approach to calculate GHG emissions from the transport segment of a CCS project.

EQUATION 6.0: Total Project Emissions from the Transport Segment

$$PE_{\text{Transport, y}} = PE_{\text{T-Comb, y}} + PE_{\text{T-VF, y}} + PE_{\text{T-Electricity, y}}$$

Where,

$PE_{\text{Transport, y}}$	=	Project emissions from CO_2 transport in year y (tCO_{2e}/yr)
$PE_{\text{T-Comb, y}}$	=	Project emissions from combustion of fossil fuels in stationary equipment used to maintain and operate the CO_2 pipeline facilities in each year (tCO_2e/yr). Refer to Equation 6.1.
$PE_{\text{T-VF, y}}$	=	Project emissions from venting events and fugitive releases from the CO_2 pipeline and associated equipment in each year (tCO_2e/yr). Refer to Equation 6.2.
$PE_{\text{T-Electricity, y}}$	=	Project emissions from electricity consumed to operate equipment the CO_2 pipeline and associated equipment in each year (tCO_2e/yr), if required by a program authority. Refer to Equation 6.2.

A variety of stationary combustion equipments are used to maintain and operate the CO_2 pipeline. Stationary combustion equipment a part of CO_2 pipeline could include engines, turbines, heaters, etc. For some projects, additional compression may be required along the pipeline or at an interconnection with a pipeline that is operated at a higher pressure. Combustion emissions associated with energy inputs to maintain and operate the CO_2 transportation infrastructure are quantified according to the following equation.

EQUATION 6.1: CO_2, CH_4, N_2O Emissions from Stationary Combustion for CO_2 Transport

$$PE_{\text{T-Comb, y}} = \sum(\text{Fuel}_i \times EF\,CO_{2\,\text{Fuel } i}) + \sum(\text{Fuel}_i \times EF\,CH_{4\,\text{Fuel } i}) \times GWP_{CH4} + \sum(\text{Fuel}_i \times EF\,N_2O_{\text{Fuel } i}) \times GWP_{N2O}$$

Where,

$PE_{\text{T-Comb, y}}$	=	Project emissions from combustion of fossil fuels in stationary equipment to maintain and operate the CO_2 transport infrastructure in each year (tCO_2e/yr).
Fuel_i	=	Volume or mass of each type of fuel, by fuel type i, used to maintain and operate the CO_2 transport infrastructure in each year (e.g., m^3/yr or kg/yr).
$EF\,CO_{2\,\text{Fuel } i}$	=	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\,CH_{4\,\text{Fuel } i}$	=	CH4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/ kg of fuel).
$EF\,N_2O_{\text{Fuel } i}$	=	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/ metric ton of fuel).
GWP_{CH4}	=	Global Warming Potential of CH_4 = 21.
GWP_{N2O}	=	Global Warming Potential of N_2O = 310.

This methodology presents a mass balance approach to calculate transport-related vented and fugitive CO_2 emissions. Venting and fugitive emissions of CO_2 are grouped together in the mass balance determination.[13]

Alternatively, in situations where a mass balance method might not appropriately apply (for instance, the uncertainty of the measured values is greater than the magnitude of the quantified emissions) vented and fugitive emissions may be estimated using a component count method. To use the component count method an inventory of equipment (fittings, valves, etc.) is compiled in order to apply fugitive emission factors to estimate emissions from the pipeline. Venting events must also be logged to estimate venting emissions (e.g., intentional pipeline releases). The component-count method to calculate vented and fugitive emissions is presented in the CO_2 storage segment calculation procedures (see Equation 7.2).

The following equation is used to quantify venting and fugitive emissions from the CO_2 pipeline according to the mass balance method.

EQUATION 6.2: Vented and Fugitive CO_2 Emissions from CO_2 Transport

$$PE_{T\text{-}VF,\,y} = CO_2\ Received_{Capture,\,y} - CO_2\ Supplied_{Storage,\,y}$$

Where,

$PE_{T\text{-}VF\ y}$	=	Project emissions from venting events and fugitive releases from the CO_2 pipeline and associated equipment in each year (tCO_2e/yr).
CO_2 Received $_{Capture,\,y}$	=	CO_2 captured and input into the pipeline, metered at the point of transfer with the capture site in each year (tCO_2/yr). Refer to Equation 6.2.A.
CO_2 Supplied $_{Storage,\,y}$	=	CO_2 supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO_2/yr). Refer to Equation 6.2.B.

EQUATION 6.2.A: CO_2 Captured and Input into CO_2 Pipeline

$$CO_2\ Received_{Capture,\,y} = Vol._{Gas\ Received,\,y} \times \%CO_2 \times \rho CO_2$$

Where,

CO_2 Received $_{Capture,\,y}$	=	CO_2 captured and input into the pipeline, metered at the point of transfer with the capture site in each year (tCO_2/yr).
Vol. $_{Gas\ Received,\,y}$	=	CO_2 captured and input into the pipeline, metered at the point of transfer with the capture site in each year ($m^3\ CO_2/yr$).
$\%CO_2$	=	% CO_2 in the gas stream measured at the point of transfer with the capture site (% volume).
ρCO_2	=	Density of CO_2 at standard conditions (metric ton/m^3).

EQUATION 6.2.B: CO_2 Transferred from CO_2 Pipeline to CO_2 Storage Site

$$CO_2\ Supplied_{Storage,\ y} = Vol._{Gas\ Supplied,\ y} \times \%CO_2 \times \rho CO_2$$

Where,

CO_2 Supplied $_{Storage,\ y}$	=	CO_2 supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO_2/yr).
Vol. $_{Gas\ Supplied,\ y}$	=	Volume of gas that has been supplied to the storage site operator, metered at the point of transfer with the storage site in each year ($m^3\ CO_2/yr$).
$\%CO_2$	=	% CO_2 in the gas stream measured at the transfer with the storage site (% volume).[14]
ρCO_2	=	Density of CO_2 at standard conditions (metric ton/ m^3).

EQUATION 6.3: CO_2e Emissions from Electricity Consumption for CO_2 Transport

$$PE_{T\text{-}Elec,\ y} = Electricity_y \times EF_{Electricity}$$

Where,

$PE_{T\text{-}Elec,\ y}$	=	Project emissions from electricity usage from equipment used to operate the CO_2 transport infrastructure in each year (tCO_2e/yr).
$Electricity_y$	=	Total metered electricity usage from equipment used to operate the CO_2 transport infrastructure in each year (MWh).
$EF_{Electricity}$	=	Emission factor for electricity generation in the relevant region (tCO_2e/MWh).

In some CCS project configurations, grid electricity may be purchased to operate the CO_2 transport infrastructure. In particular, electric-drive compressors may be used for supplemental compression along the CO_2 pipeline, where grid connectivity permits. If required by a program authority, the indirect emissions associated with purchased electricity to operate the CO_2 transport infrastructure can be quantified according to the following equation.

Calculating CO_2 Transport Emissions According to System-Wide Emission Factors. The emissions quantification procedure for the CO_2 transport segment corresponds with a CCS project that includes a dedicated pipeline moving CO_2 from the capture site to the storage site. However, CCS projects could use pipeline systems that carry streams of CO_2 from multiple capture sites to more than one geologic storage reservoirs. Thus, an emissions accounting approach that pro-rates CO_2 losses according to a proportional use of a pipeline's annual throughput or a share of a storage site's annual CO_2 injection could be appropriate. As approved by the program authority, the project developer could work with the entity responsible for the CO_2 pipeline to obtain a reasonable system-wide emission factor (percent losses of the total) and calculate its CO_2 losses (emissions). For example, if a pipeline operator has sufficient records of CO_2 imported and exported out of its system, it could determine a fugitive CO_2 factor according to a mass-balance approach. Pipeline operators could also derive a system-wide fugitive CO_2 emissions factor from a comprehensive component count assessment.[15] For completeness, a comprehensive loss factor would also incorporate vented and stationary combustion emission sources within the appropriate GHG assessment boundary, and emissions from purchased electricity if deemed appropriate by the program authority.

9.2.3 Calculation Procedures for CO_2 Storage in Non-Producing Formations

The GHG quantification method for CO_2 injection and storage in non-producing formations (i.e., saline aquifers) covers direct CO_2, CH_4, and N_2O emissions from stationary combustion, CO_2 emissions from venting and fugitive releases from injection wells and other surface equipment, and, if required by a program authority, indirect CO_2 emissions from electricity use. The methodology also accounts for CO_2 emissions that may escape from the geologic storage formation to the atmosphere, in the event such leaks are detected by the CO_2 storage site operator. GHG emission sources at a non-producing CO_2 storage site include all surface facilities for CO_2 receiving and handling located between the point of transfer with the CO_2 pipeline up to and including the injection wells, injection wells and the CO_2 storage reservoir.

CO_2e emissions from energy inputs to operate the CO_2 injection and storage facilities are accounted for using common quantification methods based on the amount and types of energy inputs. Vented CO_2 emissions from surface facilities are quantified on an event basis. Fugitive CO_2 emissions from injection wells and surface facilities are calculated according to a component count approach. The method to calculate leaked CO_2 to the atmosphere from the underground storage reservoir, should this occur, would be reservoir-specific.

The following equation is used to calculate the emissions from CO_2 storage in non-producing formations. Table 2 in Section 11 provides the calculation monitoring parameters.

EQUATION 7.0: Total Project Emissions from CO_2 Storage at Non-Producing Reservoirs

$$PE_{Storage\text{-}NP,\,y} = PE_{S\text{-}NP\text{-}Comb,\,y} + PE_{S\text{-}NP\text{-}Vent,\,y} + PE_{S\text{-}NP\text{-}Fug,\,y} + PE_{S\text{-}NP\text{-}Leakage,\,y} + PE_{S\text{-}NP\text{-}Elec,\,y}$$

Where,

$PE_{Storage\text{-}NP,\,y}$	=	Project emissions from CO_2 injection and storage in non-producing formations in each year (tCO_2e/yr).
$PE_{S\text{-}NP\text{-}Comb,\,y}$	=	Project emissions from combustion of fossil fuels in stationary equipment used to maintain and operate the CO_2 injection and storage facilities in each year (tCO_2e/yr). Refer to Equation 7.1.
$PE_{S\text{-}NP\text{-}Vent,\,y}$	=	Project emissions from venting of CO_2 at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells in the non-producing formation in each year (tCO_2e/yr). Refer to Equation 7.2.
$PE_{S\text{-}NP\text{-}Fug,\,y}$	=	Project emissions from fugitive releases of CO_2 at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells in the non-producing formation in each year (tCO_2e/yr). Refer to Equation 7.3.
$PE_{S\text{-}NP\text{-}Leakage,\,y}$	=	Project emissions from leakage of injected CO_2 from the geologic storage reservoir to the atmosphere in each year (tCO_2/yr). For information on accounting for CO_2 leakage emissions from geologic storage formations to the atmosphere see Section 9.2.5.
$PE_{S\text{-}NP\text{-}Elec,\,y}$	=	Project emissions from grid electricity used to operate equipment at the injection wells and surface facilities at the storage site in the non-producing formation in each year (tCO_2e/yr), if required by a program authority. Refer to Equation 7.4.

Similar to the CO_2 transport segment, stationary combustion equipment located at the CO_2 injection and storage site could include engines, turbines, heaters, etc; they are quantified according to the following equation.

EQUATION 7.1: CO_2, CH_4, N_2O Emissions from Stationary Combustion for CO_2 Storage in Non-Producing Formations

$$PE_{S\text{-}NP\text{-}Comb,\,y} = \sum(Fuel_{i} \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_{i} \times EF\ CH_{4\ Fuel\ i}) \times GWP_{CH4} + \sum(Fuel_{i} \times EF\ N_2O_{\ Fuel\ i}) \times GWP_{N2O}$$

Where,

$PE_{S\text{-}NP\text{-}Comb,\,y}$	=	Project emissions from combustion of fossil fuels in stationary equipment used to maintain and operate the CO_2 injection and storage facilities in each year (tCO_2e/yr).
$Fuel_{I,\,y}$	=	Volume or mass of each type of fuel, by fuel type i, used to maintain and operate the CO_2 storage infrastructure in each year (e.g., m^3/yr or kg/yr).
$EF\ CO_{2\ Fuel\ i}$	=	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4\ Fuel\ i}$	=	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/ kg of fuel).
$EF\ N_2O_{\ Fuel\ i}$	=	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/kg of fuel).
GWP_{CH4}	=	Global Warming Potential of CH_4 = 21.
GWP_{N2O}	=	Global Warming Potential of N_2O = 310.

Vented and fugitive emissions may occur from the pipeline system between the CO_2 delivery meter (or custody transfer meter) and the injection wellheads, and at the injection wellheads (immediately downstream of the meter that measures the injected volumes of CO_2). Because there is potential for vented and fugitive emissions from surface equipment located on the injection line after the point of flow measurement and before the injection well, which would not be included in a mass balance emissions calculation, the CCS Accounting Framework utilizes an event-based and component count method, respectively, to quantify these emissions from non-producing formations.[16]

Equation 7.2 calculates vented emissions by summing planned and unplanned emissions releases from CO_2 injection and handling systems (sometimes referred to as "blowdowns" and "blowouts," respectively). Equation 7.3 applies a component count approach to calculate fugitive emissions (i.e., unintentional releases of CO_2 to the atmosphere.[17]

EQUATION 7.2: Vented CO_2 Emissions from CO_2 Storage in Non-Producing Formations

$$PE_{S\text{-}NP\text{-}Vent,\,y} = \sum_{i=1}^{I} N_{Blowdown\,i,y} \times V_{Blowdown\,i,y} \times \%CO_{2_i} \times \rho_{CO_2} \times 0.001$$

Where,

$PE_{S\text{-}NP\text{-}Vent,\,y}$	=	Project emissions from venting of CO_2 at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells in the non-producing formation in each year (tCO_2/yr).
$N_{Blowdown\,i,y}$	=	Number of blowdowns for equipment 'i' in each year obtained from event logs retained by storage site operator.
$V_{Blowdown\,i}$	=	Total volume of blowdown equipment chambers for equipment 'i' (including pipelines, manifolds and vessels between isolation valves) (ft^3).
$\%CO_{2_i}$	=	Concentration of CO_2 in the injected gas in year y (Volume percent CO_2, expressed as a decimal fraction).
ρ_{CO_2}	=	Density of CO_2 at supercritical conditions in (kg/ft^3).[18]
0.001	=	Conversion factor to convert from kg to metric tons.

EQUATION 7.3: Fugitive CO_2 Emissions from injection Wells and other Surface Equipment from CO_2 Storage in Non-Producing Formations

$$PE_{S\text{-}NP\text{-}Fug,\,y} = \sum_{s=1}^{S} Count_s \times EF_s \times \%CO_{2_i} \times T_s \times \rho_{CO_2} \times 0.001$$

Where,

$PE_{S\text{-}NP\text{-}Fug,\,y}$	=	Project emissions from fugitive releases of CO_2 at the injection wells or other surface equipment located between the point of transfer with the CO_2 pipeline and the injection wells in the non-producing formation in each year (tCO_2e/yr).
$Count_s$	=	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells in the non-producing formation.
EF_s	=	Population emission factor for the specific fugitive emission source, s, listed in Table W1-A and Tables W-3 through Table W-7 of Subpart W (standard cubic feet per hour per component).
$\%CO_{2_i}$	=	Concentration of CO_2 in the injected gas (Volume percent CO_2, expressed as a decimal fraction).
T_s	=	Total time that the equipment associated with the specific fugitive emission source s was operational in year y (hours). Where equipment hours are unknown, assume 8760 hours/year.
ρ_{CO_2}	=	Density of CO_2 at standard conditions in kg/ft^3 = 0.0538 kg/ft^3.

Grid electricity may be used to operate the CO_2 injection wells, storage infrastructure and related monitoring equipment at the non-producing formation. If required by program authorities, the indirect emissions associated with purchased electricity are quantified according to the following equation.

EQUATION 7.4: CO_2e Emissions from Electricity Consumption for CO_2 Storage in Non-Producing Formations

$$PE_{S\text{-}NP\text{-}Elec,\,y} = Electricity_y \times EF_{Electricity}$$

Where,

$PE_{S\text{-}NP\text{-}Elec,\,y}$	=	Project emissions from electricity used to operate equipment at the CO_2 storage site in the non-producing formation in year y (tCO_2e/yr).
$Electricity_y$	=	Total metered electricity usage from equipment used to operate the storage site in the non-producing formation in year y (MWh).
$EF_{Electricity}$	=	Emission factor for electricity generation in the relevant region (tCO_2e/MWh).

9.2.4 Calculation Procedures for CO_2 Storage in Producing Formations

The emissions calculation procedures for CO_2 storage at producing formations (i.e., enhanced oil and gas recovery sites) cover direct CO_2, CH_4, and N_2O emissions from stationary combustion; CO_2 emissions from venting and fugitive releases to the atmosphere; and, if required by program authorities, indirect CO_2e emissions from purchased electricity use. GHG sources include CO_2 receiving, injecting, recycling and re-injection equipment; CO_2 injection and production wells, hydrocarbon processing and storage facilities; and the CO_2 storage reservoir.

Similar to non-producing formations, the emissions quantification methodology for CO_2 storage in enhanced oil and gas recovery formations includes all emissions sources located between the point of transfer with the CO_2 pipeline up to and including the injection wells. It also incorporates producing wells and surface facilities related to the hydrocarbon gathering, storage and separation facilities and the infrastructure used to process, purify and compress CO_2 and other gases produced from the formation, and re-inject it back into the formation. Additionally, CO_2 entrained in or dissolved in hydrocarbons (crude oil or natural gas) or waste water that is removed or distributed off-site (e.g., sold, disposed of and/or not re-injected) is accounted for as a source of fugitive emissions.

Emissions from energy inputs to operate the facilities at enhanced oil and gas recovery formations are accounted for by using common quantification methods based on the quantities and types of energy inputs. Vented CO_2 emissions from surface facilities are quantified on an event basis. Fugitive CO_2 emissions from injection wells and surface facilities are calculated according to a component count approach. The method to calculate leaked CO_2 from the geologic storage reservoir to the atmosphere, should it occur, would be reservoir-specific.

The CCS Accounting Framework does not treat CO_2 produced from wells at enhanced oil or gas recovery operations that is recycled and re-injection into the storage formation as an emission, provided the CO_2 remains within the closed loop system and thus prevented from entering the atmosphere. Unintentional CO_2 releases from the recycle system (including from production wells, gas separation and cleaning equipment) are treated as fugitive emissions and accounted for in Equation 8.3. Intentionally vented CO_2 in the recycle system (for operational purposes) is treated as a vented emission and accounted for in Equation 8.2.

The following equation outlines the methods for calculating emissions from CO_2 storage in producing formations. Table 2 in Section 11 provides monitoring parameters for calculating emissions from CO_2 storage in producing formations.

EQUATION 8.0: Total Project Emissions from CO_2 Storage at Producing Reservoirs

$$PE_{\text{Storage-P, y}} = PE_{\text{S-P-Comb, y}} + PE_{\text{S-P-Vent, y}} + PE_{\text{S-P-Fug, y}} + PE_{\text{S-P-Leakage, y}} + PE_{\text{S-P-CO2 Transfer}} + PE_{\text{S-P-Elec, y}}$$

Where,

$PE_{\text{Storage-P, y}}$	=	Project emissions from CO_2 injection and storage in producing formations in each year (tCO_2e/yr).
$PE_{\text{S-P-Comb, y}}$	=	Project emissions from combustion of fossil fuels in stationary equipment at the storage site—e.g., to maintain and operate the CO_2 handling and injection wells, CO_2 recycling devices, and associated hydrocarbon production facilities in each year (tCO_2e/yr). Refer to Equation 8.1.
$PE_{\text{S-P-Vent, y}}$	=	Project emissions from venting of CO_2 at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells in the producing formation; at the producing wells; at the hydrocarbon gathering processing and storage facilities; or at the CO_2 processing and recycling facilities in each year (tCO_2e/yr). Refer to Equation 8.2.
$PE_{\text{S-P-Fug, y}}$	=	Project emissions from fugitive releases of CO_2 or CH_4 at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; at the CO_2 processing and recycling facilities; and from CO_2 entrained in hydrocarbons or water produced from the formation and distributed off-site in each year (tCO_2e/yr). Refer to Equation 8.3.
$PE_{\text{S-P-Leakage, y}}$	=	Project emissions from leakage of injected CO_2 from the geologic storage reservoir in the producing formation to the atmosphere in each year (tCO_2e/yr). For information on accounting for CO_2 leakage emissions from geologic storage formations to the atmosphere see Section 9.2.5.
$PE_{\text{S-P-CO2 Transfer}}$	=	Produced CO_2 from an enhanced oil or gas recovery operation transferred offsite in each year (tCO_2/yr). Refer to Equation 8.5.
$PE_{\text{S-P-Elec, y}}$	=	Project emissions from consumption of electricity used to operate equipment at the producing formation in each year (tCO_2e/yr), if required by a program authorities. Refer to Equation 8.4.

Various types of stationary combustion equipment may be used to maintain and operate the CO_2 injection, storage, processing and recycling facilities and to operate the enhanced oil and gas recovery facilities (e.g., batteries, gathering systems, oil-water-gas separators). The following equation is used to quantify GHG emissions from all stationary fossil fuel-driven equipment used to operate the CO_2 injection and storage facilities. [19]

EQUATION 8.1: CO_2, CH_4, N_2O Emissions from Stationary Combustion for CO_2 Storage at Producing Formations

$$PE_{S\text{-}NP\text{-}Comb,\,y} = \sum(Fuel_i \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times GWP_{CH4} + \sum(Fuel_i \times EF\ N_2O\ Fuel_i) \times GWP_{N2O}$$

Where,

$PE_{S\text{-}P\text{-}Comb,\,y}$	=	Project emissions from combustion of fossil fuels in stationary equipment at the producing storage site—e.g., to maintain and operate the CO_2 handling and injection wells, CO_2 recycling devices, and associated hydrocarbon production facilities in each year (tCO_2e/yr). Refer to Equation 8.1.
$Fuel_{i,\,y}$	=	Volume or mass of each type of fuel, by fuel type i, used to inspect, maintain and operate the CO_2 storage infrastructure and hydrocarbon production facilities in each year (e.g., m^3/yr or kg/yr).
$EF\ CO_{2\ Fuel\ i}$	=	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4\ Fuel\ i}$	=	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
$EF\ N_2O_{Fuel\ i}$	=	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/kg of fuel).
GWP_{CH4}	=	Global Warming Potential of CH_4 = 21.
GWP_{N2O}	=	Global Warming Potential of N_2O = 310.

Venting may occur at the injection wells or at other surface facilities, located between the CO_2 transfer meter at the pipeline and the injection wells. It could also happen at the production wells, the hydrocarbon production and storage facilities or at the facilities used to process and recycle the produced CO_2 for re-injection into the formation. Planned venting may take place during shutdowns and maintenance work, while unplanned venting may occur during upsets to operations. Venting events should be logged.

The following equation can be used to calculate vented emissions from the injection wells and other surface facilities at the CO_2 storage site.

EQUATION 8.2: Vented CO_2e Emissions from CO_2 Storage at Producing Formations

$$PE_{S\text{-}P\text{-}Vent,\,y} = \sum_{i=1}^{I} N_{Blowdown\,i} \times V_{Blowdown\,i} \times \%GHG_i \times \rho_{GHG} \times GWP \times 0.001$$

Where,

$PE_{S\text{-}P\text{-}Vent,\,y}$	=	Project emissions from vented CO_2 at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells in the producing formation; at the producing wells; at the hydrocarbon gathering processing and storage facilities; or at the CO_2 processing and recycling facilities in each year (tCO_2e/yr).
$N_{Blowdown\,i}$	=	Number of blowdowns for equipment i in each year, obtained from blowdown event logs retained by storage site operator.
$V_{Blowdown\,i}$	=	Total volume of blowdown equipment chambers for equipment i (including pipelines, manifolds and vessels between isolation valves) (m^3, ft^3).
$\%GHG_i$	=	Concentration of GHG 'i' in the injected gas in year y (Volume percent GHG, expressed as a decimal fraction).
$\rho_{GHG\,i}$	=	Density of relevant GHG (CO_2 or CH_4) at standard conditions in kg/m^3 or kg/ft^3.[20]
GWP	=	100 year Global Warming Potential of relevant GHG (CO_2 =1 and CH_4 =21).
0.001	=	Conversion factor to convert from kg to metric tons.

Fugitive emissions of CO_2, and in some cases methane, may occur at the injection wells or at other surface facilities, located between the CO_2 pipeline transfer meter and the injection wells. Fugitive emissions could also happen at production wells, the hydrocarbon production and storage facilities, and/or at the facilities used to process and recycle the produced CO_2 for re-injection into the formation. Fugitive emission sources could include fittings, flanges, valves, connectors, meters, and headers (large pipes that mix the oil stream from multiple wellheads). Fugitive emissions may also result from the release of residual CO_2 entrained or dissolved in produced oil, water or gas that is transferred from the hydrocarbon recovery facilities to downstream users.

Fugitive CO_2 and CH_4 emissions from injection wells and other surface equipment are calculated on a component count approach. Fugitive emissions of CO_2 entrained in or dissolved in hydrocarbon liquids or gases or water produced from the formation and distributed off-site are calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product.

The following equation is used to calculate fugitive emissions from the injection wells and other surface facilities at the CO_2 storage site.

EQUATION 8.3: Fugitive CO_2e Emissions from Wells and Surface Equipment at Producing Formations

$$PE_{\text{S-P -Fugitive, y}} = PE_{\text{S-P -Fug-Equipment, y}} + PE_{\text{S-P -Fug-Entrained CO2, y}}$$

Where,

$PE_{\text{S-P-Fugitive, y}}$	=	Project emissions from fugitive releases of CO_2 or CH_4 at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; at the CO_2 processing and recycling facilities; and from CO_2 entrained in hydrocarbons or water produced from the formation and distributed off-site in each year (tCO_2e/yr).
$PE_{\text{S-P -Fug-Equipment, y}}$	=	Fugitive emissions of CO_2 (and CH_4 if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO_2 processing and recycling facilities in each year (tCO_2e/yr). Refer to Equation 8.3.A.
$PE_{\text{S-P -Fug-Entrained CO2, y}}$	=	Fugitive emissions of CO_2 entrained in or dissolved in hydrocarbon liquids or gases or water produced from the formation and distributed off-site (sold or otherwise disposed of and not re-injected) in each year (tCO_2/yr). Refer to Equation 8.3.B.

EQUATION 8.3.A: CO_2 & CH_4 Fugitive Emissions from Equipment Leaks at Producing Formations

$$PE_{S\text{-}P\text{-}Fug\text{-}Equipment,\,y} = \sum_i \sum_{s=1}^{s} Count_s \times EF_s \times \%GHG_i \times T_s \times \rho_{GHG} \times GWP \times 0.001$$

Where,

$PE_{S\text{-}P\text{-}Fug\text{-}Equipment,\,y}$	=	Fugitive of GHG 'i' (CO_2 and CH_4, if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO_2 processing and recycling facilities in each year (tCO_2e/yr).
$Count_s$	=	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO_2 processing and recycling facilities.
EF_s	=	Population emission factor for the specific fugitive emission source, 's', in Table W1-A and Tables W-3 through Table W-7 of Subpart W (standard cubic feet per hour per component).
$\%GHG_i$	=	Concentration of GHG 'i' (CO_2 or CH_4) in the injected or produced gas (Volume percent CO_2 or CH_4, expressed as a decimal fraction).
T_s	=	Total time that the equipment associated with the specific fugitive emission source s was operational in year y (hours). Where equipment hours are unknown, assume 8760 hours/year.
ρ_{GHG}	=	Density of relevant GHG (CO_2 or CH_4) at standard conditions in kg/m^3 or kg/ft^3.
GWP	=	100 year Global Warming Potential of relevant GHG (CO_2 =1 and CH_4 =21).
0.001	=	Conversion factor to convert from kg to metric tons.

EQUATION 8.3.B: CO_2 Fugitive Emissions Entrained in Produced Hydrocarbons at Producing Formations

$$PE_{\text{S-P-Fug-Entrained CO2, y}} = (Vol._{\text{Gas Sold y}} \times \%\, CO_{2\,\text{Gas Sold y}} \times \rho\, CO_2 \times 0.001) + (Mass_{\text{Water Prod}} \times Mass\ Frac_{\text{CO2 in Water}}) + (Mass_{\text{Hydrocarbons Prod}} \times Mass\ Frac_{\text{CO2 in Oil}})$$

Where,

$PE_{\text{S-P-Fug-Entrained CO2, y}}$	=	Fugitive emissions or other losses of CO_2 entrained or dissolved in crude oil/other hydrocarbons, produced water and natural gas that have been separated from the produced CO_2 for sale or disposal. Calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product.
$Vol._{\text{Gas Sold y}}$	=	Volume of natural gas or fuel gas, produced from the formation that CO_2 is being injected into, that is sold to third parties or input into a natural gas pipeline in year y (m^3/yr, measured at standard conditions).
$\%\, CO_{2\,\text{Gas Sold y}}$	=	% CO_2 in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year y (% volume).
$\rho\, CO_2$	=	Density of CO_2 at standard conditions (kg ton/m^3 or ft^3).
0.001	=	Conversion factor to convert from kg to metric tons.
$Mass_{\text{Water Prod}}$	=	Mass of water produced from the formation that CO_2 is being injected into, that is disposed of or otherwise not-re-injected back into the formation (metric tons/yr).
$Mass\ Frac_{\text{CO2 in Water}}$	=	Mass fraction of CO_2 in the water produced from the formation (unitless).
$Mass_{\text{Hydrocarbons Prod}}$	=	Mass of crude oil and other hydrocarbons produced from the formation that CO_2 is being injected into (metric tons/year).
$Mass\ Frac_{\text{CO2 in Oil}}$	=	Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation (unitless).

Purchased electricity may be used to operate pumps, compressors and other equipment at the injection wells and producing wells; at oil and gas gathering, storage and processing facilities (e.g., oil-water-gas separators); or at CO_2 processing, compression, recycling and re-injection facilities.

For example, many enhanced oil and gas recovery projects install additional water pumping capacity to alternate water injection and CO_2 injection (water alternating gas (WAG) injection), which may also require electricity. Electric compression could be used to recycle produced CO_2 and other gases for re-injection into the formation. In addition to the recycle compressors, additional electric-drive equipment may be used to operate vapor recovery units to recover vapors from oil and water tanks, to operate flash gas compressors which increase the pressure of the recovered vapors for recycling, to operate glycol dehydrators and glycol circulation pumps that remove moisture from the produced gas, and to operate other auxiliary equipment such as instrument air compressors and cooling fans.

If required by a program authority, indirect GHG emissions from with purchased electricity used to operate equipment at the enhanced oil and gas recovery operations are quantified according to the following equation.

EQUATION 8.4: CO_2e Emissions from Purchased Electricity Consumption for CO_2 Storage at Producing Formations

$$PE_{S\text{-}P\text{-}Elec,\ y} = Electricity_y \times EF\ Electricity$$

Where,

$PE_{S\text{-}P\text{-}Elec,\ y}$	=	Project emissions from electricity used to operate equipment at the CO_2 storage site in the producing formation in each year (tCO_2e/yr).
$Electricity_y$	=	Total metered electricity usage from equipment used to operate the storage site in the producing formation and the hydrocarbon production facilities in year y (MWh).
$EF_{Electricity}$	=	Emission factor for electricity generation in the relevant region (tCO_2e/MWh).

While CO_2 transferred out of the project boundary is not necessarily an emission to the atmosphere, project developers should nevertheless not account for it as if it were sequestered from the atmosphere.

For project accounting purposes to determine emissions reductions, the CCS Accounting Methodology does treat produced-CO_2 from an enhanced oil or gas recovery operation that is transferred outside the project boundary as an emission. A project developer could move produced-CO_2 between enhanced oil or gas production fields if it includes the multiple fields within the project boundary (making sure to account for emissions from the relevant stationary combustion, vented, and fugitive sources at all the fields, and between fields, in which the captured CO_2 is injected).

Equation 8.5 presents the approach to calculate CO_2 transferred outside the project boundary.

EQUATION 8.5: CO_2 Transferred Outside Project Boundaries at Producing Formations

$$PE_{S\text{-}P\text{-}CO2\_Transfer\ y} = Vol_{CO2\_Transfer\ y} \times \rho CO_2 \times 0.001$$

Where,

$PE_{S\text{-}P\text{-}CO2\ Transfer\ y}$	=	Produced CO_2 from an enhanced oil or gas operation transferred outside project boundary in each year (tCO_2/yr).
$Vol_{CO2\_Transfer\ y}$	=	Volume of produced CO_2 from an enhanced oil or gas operation transferred outside project boundary in each year (m^3, ft^3).
ρCO_2	=	Density of CO_2 at standard conditions (kg/m^3 or ft^3).
0.001	=	Conversion factor to convert from kg to metric tons.

9.2.5 Accounting for CO_2 Leakage from Geologic Storage Formations to the Atmosphere

Project developers must quantify fugitive CO_2 emissions from the geologic storage reservoir to the atmosphere, if they arise. This applies to CO_2 storage at non-producing and producing formations.

Detecting leakage from the geologic reservoir that could lead to emissions to the atmosphere might involve a comparison of deep subsurface operational monitoring results to reservoir and CO_2 injection models designed to predict the behavior of injected CO_2 within the storage complex. Project developers could also deploy monitoring devices to detect leakage of CO_2 at the surface, in which a comparison would be made between surface monitoring data and natural variations in CO_2 levels from organic matter and vegetation in the local environment. Other monitoring tools could also provide information on site performance indicators, the location and size of the CO_2 plume, environmental receptors, and other factors.

Project developers and program authorities should work together to establish CO_2 detection thresholds to calibrate monitoring systems in a manner that provides confidence in the monitoring program's ability to accurately confirm the effectiveness of the CO_2 storage complex.[21] Section 12 provides a brief overview of monitoring CO_2 in geologic formations, by project development phase; it also includes a set of resources that provide guidance for monitoring CO_2 in geologic formations.

Examples of conduits for CO_2 leaks to the atmosphere include CO_2 injection wells, oil or gas production wells (if applicable), monitoring wells and abandoned wells;[22] CO_2 could also escape the geologic containment complex through faults and fissures. However, for properly selected, operated, and closed CO_2 storage operations, fugitive CO_2 emissions from the geologic reservoir to the atmosphere should not occur.

For a CO_2 storage site in compliance with its CO_2 injection permit the value of the "$CO_{2\text{-}z}$" term in Equation 9 should be zero. That is, it is reasonable to expect that leakage to the atmosphere is not a threat and zero is an acceptable value for the "$CO_{2\text{-}z}$" term in Equation 9 if:

- "Conformance monitoring systems" show that the behavior of CO_2 within the injection zone in the storage complex agrees with modeled predictions and the key assumptions in the site permit are confirmed; and/or
- "Assurance monitoring systems" above (and, if appropriate to the site, lateral to) the injection zone in the storage complex do not detect injected CO_2.

In the event that leaks from the subsurface CO_2 containment complex do happen, which are not mitigated by the project developer and result in emissions to the atmosphere, project developers would quantify the fugitive CO_2 emissions on a site-by-site basis, according to an approach approved by the program authority. The project monitoring plan should include a strategy for detecting and quantifying any surface CO_2 leakage. In the event of containment failure, program authorities could allow a "write-off" calculation based on a simplified estimation to conservatively determine maximum leakage, rather than requiring rigorous quantification.

Generally, the exercise to quantify the total amount of CO_2 emissions from the geologic storage complex, which the subsurface monitoring systems indicate will enter the atmosphere (or the surface systems show have crossed from the subsurface to the surface), will involve a sophisticated computation that incorporates a range of information about the specific geologic reservoir, the CO_2 injection regime, modeling assumptions, and other variables.

The following general equation to account for fugitive CO_2 emissions from the CO_2 storage complex to the atmosphere reproduces a formula from the EPA's Greenhouse Gas Reporting Program. It directs storage site operators to identify leakage pathways from the subsurface and aggregate total annual emissions from each CO_2 emissions pathway, should a leak be detected.

EQUATION 9: Fugitive CO_2 Emissions from Underground CO_2 Storage Formations*

$$CO_{2_{Leakage-NP}} = \sum_{z=1}^{Z} CO_{2_z}$$

Where,

$CO_{2_{Leakage-NP}}$	=	Total mass of CO_2 emitted through subsurface leakage from the non-producing formation in year y (metric tons).
CO_{2_z}	=	Total mass of CO_2 emitted through leakage pathway z in year y (metric tons).
z	=	Leakage pathway.

* 40 CFR §98.443(e), Eq. RR-10, 40

Box 4 presents the European Union's (EU) method to calculate fugitive CO_2 emissions from geological storage. It also relies on project developers to create a site-specific leak detection and quantification approach.

BOX 4: EU Method to Calculate Fugitive CO_2 Storage Emissions*

Monitoring shall start in the case that any leakage results in emissions or release to the water column. Emissions resulting from a release of CO_2 into the water column shall be deemed to be equal to the amount released to the water column. Monitoring of emissions or of release into the water column from a leakage shall continue until corrective measures pursuant to Article 16 of Directive 2009/31/EC have been taken and emissions or release into the water column can no longer be detected. Emissions and release to the water column shall be quantified as follows:

$$\mathbf{CO_2\ emitted\ [tCO_2] = \sum_{T-start}^{T-end} L\ CO_2\ [\frac{tCO_2}{d}]}$$

L CO_2	=	mass of CO_2 emitted or released per calendar day due to the leakage. For each calendar day for which leakage is monitored it shall be calculated as the average of the mass leaked per hour [tCO_2/h] multiplied by 24. The mass leaked per hour shall be determined according to the provisions in the approved monitoring plan for the storage site and the leakage. For each calendar day prior to commencement of monitoring, the mass leaked per day shall be taken to equal the mass leaked per day for the first day of monitoring.
T-start	=	the latest of: (a) the last date when no emissions or release to the water column from the source under consideration were reported; (b) the date the CO_2 injection started; and (c) another date such that there is evidence demonstrating to the satisfaction of the competent authority that the emission or release to the water column cannot have started before that date.
T-end	=	the date by which corrective measures pursuant to Article 16 of Directive 2009/31/EC have been taken and emissions or release to the water column can no longer be detected.

Other methods for quantification of emissions or release into the water column from leakages can be applied if approved by the competent authority on the basis of providing a higher accuracy than the above approach. The amount of emissions leaked from the storage complex shall be quantified for each of the leakage events with a maximum overall uncertainty over the reporting period of ± 7.5 %. In case the overall uncertainty of the applied quantification approach exceeds ± 7.5 %, an adjustment shall be applied, as follows:

$$CO_{2,\ Reported}\ [tCO_2\ ] = CO_{2,\ Quantified}\ [tCO2\ ] \times (1 + (Uncertainty\ _{System}\ [\%]/100) - 0.075)$$

With

$CO_{2,\ Reported}$	=	Amount of CO_2 to be included into the annual emission report with regards to the leakage event in question;
$CO_{2,\ Quantified}$	=	Amount of CO_2 determined through the used quantification approach for the leakage event in question;
Uncertainty, $_{System}$	=	The level of uncertainty which is associated to the quantification approach used for the leakage event in question, determined according to section 7 of Annex I to these guidelines.

* EU 2010, ANNEX XVIII—Activity-specific guidelines for the geological storage of CO_2 in a storage site permitted under Directive 2009/31/EC; 3. Leakage from the Geologic Storage Complex.

CCS PROJECT MONITORING

All projects that seek recognition for the GHG reductions associated with capturing, transporting, and storing CO_2 must monitor their operations.[23] Generally, project monitoring involves installing technologies and creating systems to collect, organize, and process data. From CO_2 capture to storage, project developers monitor equipment operations and performance, process flows, environmental and geologic indicators, changes in natural systems, among other data points. Project developers must also check that project management and operating practices are designed to facilitate monitoring objectives.

In addition to providing assurance about a CCS project's actual GHG reductions (which includes monitoring the effectiveness of a CCS project to permanently sequester CO_2 from the atmosphere) other monitoring goals may include:

- Complying with regulations,
- Assessing project performance for commercial reasons,
- Ensuring environmental and human health and safety,
- Informing project stakeholders and investors, and
- Advancing understanding through education and outreach.

With regards to CCS projects, monitoring the effectiveness of geologic CO_2 storage dominates the discussion. There is less experience associated with predicting and tracking large volumes of injected CO_2 into geologic formations with accuracy and precision compared to monitoring above-ground CO_2 capture and handling systems. Challenges ultimately stem from the unique nature of each geologic storage reservoir and the complexity involved in measuring and understanding the behaviour of injected CO_2, as well as detecting the response of the accepting rock formation and surrounding geologic and natural systems. In comparison, measuring fuel consumption and gas flows associated with producing, capturing, and transporting CO_2 in above-ground equipment uses devices like meters and gauges that are more commonly used.

Scope of Project Monitoring in the CCS Accounting Framework. While project developers will implement monitoring systems to address a range of goals, the CCS Accounting Framework focuses on monitoring project activity parameters that inform the calculation of GHG reductions associated implementing CCS projects.[24] As such, the project monitoring guidance in Section 11 includes data collection methods to determine baseline and project emissions, in correspondence with the GHG quantification procedures in Section 9. This monitoring guidance provides specific suggestions on how, where, and sometimes when to collect data from CO_2 capture sites, pipelines, storage sites.

Because of the geologic complexity and uniqueness of monitoring below-ground storage of injected CO_2, Section 12 provides a list of resources for monitoring technologies and techniques; they are intended to inform project developers about options that can be deployed across project phases. The diversity of these options reflects the reality that each site is unique and site-specific reservoir conditions preclude the development of a single prescriptive monitoring guidance document. Instead of imposing a one-size-fits-all monitoring regime for CO_2 storage sites, the CCS Accounting Framework encourages project developers to use "best practices" to design a site-specific CO_2 storage monitoring plan, which would be incorporated into an overall monitoring plan for the entire CCS project as described in the next section (Section 10).

10. MONITORING PLANS

Monitoring plans are commonly project developer-created documents that describe how a CCS project will be observed and performance checked over time. And once a project has commenced operation, program authorities also expect project developers to regularly report project activities and disclosure the results of the project.

A CCS project that seeks recognition for GHG emissions reductions should design monitoring plans according to the ISO 14064-2 principles of transparency and accuracy, such that data capture and organization enables the replication and verification of calculated GHG reductions and that the fate of injected CO_2 can be understood.

For the CO_2 capture and pipeline segments of a CCS project, as well as for above ground equipment at CO_2 storage sites, monitoring plans provide information that demonstrates the defined calculation methods (as presented in Section 9, for example) have been adequately followed, and that GHG activity data have been collected and applied in a manner consistent with the prescribed calculation approach.

On the other hand, monitoring plans have special significance for the CO_2 storage component of CCS projects, different from CO_2 capture and transport. Site-specific and sufficiently flexible to be adjusted and refined over time in response to new information, the plans describe monitoring programs designed to collect data and update predictive models on geologic and natural systems that display variability. The CO_2 storage monitoring plans identify and explain technologies appropriate for the unique geologic, environmental, and operational conditions that exist at each site.

Ultimately, project developers must design project monitoring plans consistent with reporting requirements and objectives of program authorities. In addition to the activity data to determine stationary combustion, venting, fugitive, and (if required by a program authority) indirect emissions, as determined according to the calculation methodology presented in Section 9 (See Table 2 below), a comprehensive monitoring plan would also include, at a minimum, the following information about total CO_2 captured, transported, and stored, as well as :

- Total CO_2 produced from the primary process.
- Total output (e.g., MWh, MMscf) from the primary process (output/year).
- Total CO_2 input into the pipeline at the capture site.
- Total CO_2 received at storage site from pipeline.
- Total CO_2 injected at each injection well into producing and/or non-producing. Reservoirs.
- Total CO_2 produced from producing wells in the storage formation.
- Total CO_2 recycled back to the injection well(s) from wells in the producing formation (in the current year and the prior year).
- Total energy inputs used to run CCS-related equipment at the CO_2 capture, transport, inject and storage operations, including:
    - Direct fossil fuel inputs (combustion).
    - Indirect energy inputs (e.g., grid electricity purchases and electricity and/or steam from purchased from third party cogeneration facilities).
    - Total electricity or steam consumed to compensate for energy demands associated with operating the CO_2 capture process; or reduced output at power plant due to these parasitic loads, e.g., decreased MWh due to diversion of steam from the power generation steam cycle to operate capture equipment).
- Logs of intentional CO_2 venting events (blowdowns) and occurrences of unintentional CO_2 venting (blowouts) at the CO_2 capture, transport, injection and storage sites, including the volume and composition of gas vented in each instance.
- Total volume of gas flared at hydrocarbon production facilities at the storage site in the producing formation, and composition of gas stream.
- Equipment inventories and equipment operating hours to characterize sources of fugitive emissions at the injection and storage sites.
- Quantities of hydrocarbon liquids (crude oil and natural gas liquids), gases (associated gas, solution gas or natural gas) and water produced from the formation that CO_2 is being injected into (that may contain entrained or dissolved CO_2 originating from the capture site) and the fraction of CO_2 contained in each phase (e.g., dissolved or entrained CO_2 in the produced liquids or gases).
- CO_2 leakage events from the storage formation.[25]

With respect to CO_2 storage sites with UIC Class VI permitted wells in the U.S., these facilities must develop site-specific monitoring plans, consistent with EPA's GHGRP, Subpart RR, as do facilities with UIC Class II permitted wells that elect to report under Subpart RR. The under EPA's GHGRP monitoring plans are intended to complement and augment the permitted CO_2 monitoring requirements under the UIC program, which support protection of underground sources of drinking water.

The main contents of a monitoring plan for Subpart RR under EPA's GHGRP include:[26]

- Delineation of the maximum monitoring area and the active monitoring areas;[27]
- Identification of potential surface leakage pathways for CO_2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways;
- A strategy for detecting and quantifying any surface leakage of CO_2;
- A strategy for establishing the expected baselines for monitoring CO_2 surface leakage; and
- A summary of the considerations you intend to use to calculate site-specific variables for [EPA's] mass balance equation.

CO_2 capture sites (either power generation- or industrial-based), as well as enhanced oil recovery and enhanced gas recovery operations must also develop a monitoring plan in compliance with the requirements of other Subparts to EPA GHGRP. For example, Subpart A provides general provisions to the program, Subpart D covers electricity generation, Subpart W covers petroleum and natural gas systems, and Subpart PP covers suppliers of carbon dioxide. Depending on the CO_2 capture site, other Subparts may apply.[28]

Furthermore, consistent with the project monitoring rules created by a program authority, CCS project developers should establish quality assurance mechanisms for controlling gaps and managing the integrity of data collection. Project developers should also maintain gas flow and fuel use meters to function within their designed range of operating conditions and calibrated on a regular basis.[29]

11. MONITORING PARAMETERS TO QUANTIFY GHG REDUCTIONS

This section provides information about parameters to monitor to calculate GHG savings from a CCS project according to the quantification procedures in Section 9–Table 2. Project developers would incorporate this information into their respective monitoring plans and adapt it to accommodate the specific conditions associated with their CCS project.

To ensure the validity of GHG reduction claims, data collection and monitoring is essential. The following table aggregates the specific monitoring parameters and activities needed for a comprehensive assessment of the GHG reductions that might be claimed by a project developer. Project developers should take into account the location, type of equipment and frequency of measurement for each variable.

TABLE 2: Monitoring Parameters

PARAMETER	DESCRIPTION	UNITS	COMMENT
PROJECTION-BASED BASELINE			
$Vol._{Gas\ Produced}$	Total volume of gas (containing CO_2 and other compounds) produced from the primary process in the project condition, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in year y.	m^3/yr	Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is defined by the program authority.
$\%CO_2$	% CO_2 in the gas stream from the primary process in the project condition, measured immediately downstream of the primary process, in each year.	% CO_2 by volume	Direct measurement of the composition of the gas stream on a monthly basis is recommended. Gas analyzers should be calibrated in accordance with manufacturer's specifications.
STANDARDS-BASED BASELINE			
Output	Units of output from the CO_2 capture facility (e.g., MWh) in the project condition in year y.	Units of output (e.g., MWh)	Defined by the program authority. Measurement based on the type of primary process. Output should be measured to account for the total output from the primary process that would have occurred in the absence of the project.

TABLE 2: Monitoring Parameters *(continued)*

PARAMETER	DESCRIPTION	UNITS	COMMENT
NON-CAPTURED CO_2 EMISSIONS FROM THE PRIMARY PROCESS			
$Vol._{Gas\ Produced}$	Total volume of gas (containing CO_2 and other compounds) produced from the primary process, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in year y.	m^3/yr, scf/yr	Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is defined by the program authority.
$\%CO_2$	% CO_2 in the gas stream from the primary process, measured immediately downstream of the primary process, in year y. % CO_2 in the captured gas stream, measured at the input to the pipeline, in year y.	% CO_2 by volume	Direct measurement of the composition of the gas stream on a monthly basis according to program authority rules. Gas analyzers should be calibrated in accordance with manufacturer's specifications.
Fuel i	Volume or mass of each type of fuel, by fuel type i, burned by combusted by the primary process in year y.	Liters, gallons, m3, scf, metric tons	Continuous metering of gaseous fuels or reconciliation of volumes or masses purchased and in storage (e.g., for liquid or solid fuels) as determined by the program authority.
$Mass\ Frac._{Carbon\ i}$	Average mass fraction of carbon in the fuel, by fuel type I, in year y.	Fraction, expressed as a decimal	Direct measurement of the carbon content of the fuel by a third party lab on a basis recommended by a program authority.
$Vol._{Gas\ Transferred}$	Volume of gas (containing primarily CO_2) captured and input into the pipeline, metered at the point of transfer with the pipeline (or equivalent), measured at standard conditions, in year y.	m^3/yr, scf/yr	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is defined by the program authority.

TABLE 2: Monitoring Parameters *(continued)*

PARAMETER	DESCRIPTION	UNITS	COMMENT
STATIONARY COMBUSTION EMISSIONS FOR CO_2, CH_4, AND N_2O			
Fuel i (gaseous fuels)	Volume of each type of gaseous fuel, by fuel type i, used to used to operate each component (capture, transport, and storage) of the CCS project in year y.	m^3, scf	Continuous measurement of the gas flow rate, where the frequency of continuous measurement is defined by the program authority. Volumetric flow meter readings should be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures (e.g., 15°C and 1atm). Flow meters should be placed a sufficient distance from any obstructions to ensure accurate flow measurements. Flow meters used to measure the volume of natural gas should be calibrated according to manufacturer specifications.
Fuel i (liquid or solid fuels)	Volume or mass of each type of liquid or solid fuel, by fuel type i, used to used to operate fossil fuelled components (capture, transport, and storage) in the CCS project in year y.	Liter, gallons, metric tons	Reconciliation of purchasing records at a frequency determined by the program authority and inventory adjustments as needed. Volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets would be an acceptable means to determine the volumes of fossil fuels consumed to operate the CCS project.

TABLE 2: Monitoring Parameters *(continued)*

PARAMETER	DESCRIPTION	UNITS	COMMENT
INDIRECT CO_2 EMISSIONS FROM PURCHASED AND CONSUMED ELECTRICITY, STEAM, HEAT (IF REQUIRED BY A PROGRAM AUTHORITY)			
Electricity	Metered electricity usage from equipment used to operate electrically driven component (capture, transport, and storage) in the CCS project in year y.	MWh	Continuous measurement of electricity consumption or reconciliation of maximum kW rating for each type of equipment and operating hours. Electricity meters should be calibrated by an accredited party at a frequency determined by the program authority. Electricity consumption should be metered continuously wherever possible for the CCS project; however, in certain cases other loads may be tied into the same electricity meter and estimates may be required. In these cases the maximum kW rating of each piece of equipment could be used in conjunction with a conservative estimate of operating hours (e.g., 8760 hours per year) to estimate the electricity consumption.
Total Fuel Cogen	Total volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit supplying electricity or thermal energy to the CO_2 capture and compression facilities in year y.	Liters, gallons, m^3, scf, metric tons	Continuous metering of gaseous fuels or reconciliation of volumes or masses (e.g., for liquid or solid fuels) purchased and in storage at a frequency determined by the program authority.
Heat CCS Project	Quantity of thermal energy purchased from the third party cogeneration unit to operate the CO_2 capture facilities in year y.	MWh	Continuous metering of thermal energy sales/purchases to/for the CCS project using a utility meter. Steam meters, or similar, should be calibrated by a program-authority-accredited party at a frequency determined by the program authority.
Electricity CCS Project	Quantity of electricity purchased from the third party cogeneration unit to operate the CO_2 capture and compression facilities in year y.	MWh	Continuous measurement of electricity sales/purchases to/for the CCS project. Electricity meters should be calibrated by program-authority-accredited party at a frequency determined by the program authority.

TABLE 2: Monitoring Parameters *(continued)*

PARAMETER	DESCRIPTION	UNITS	COMMENT
Heat Cogen	Total quantity of thermal energy generated by the third party cogeneration unit in year y.	MWh	Continuous metering of total thermal energy sales using a utility meter. Steam meters, or similar, should be calibrated by program-authority-accredited party at a frequency determined by the program authority.
Electricity Cogen	Total quantity of electricity generated by the third party cogeneration unit in year y.	MWh	Continuous measurement of total electricity sales/purchases. Electricity meters should be calibrated by program-authority-accredited party at a frequency determined by the program authority.
VENTED AND FUGITIVE CO_2 EMISSIONS FROM CO_2 TRANSPORT—MASS BALANCE			
$Vol._{Gas\ Received}$	Volume of gas (containing primarily CO_2) captured and input into the pipeline, metered at the point of transfer with the pipeline (or equivalent), measured at standard conditions, in year y.	m^3/yr, scf/yr	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is defined by the program authority.
$\%CO_2$	% CO_2 in the gas stream being transported by pipeline, measured at the input to the pipeline, in year y.	% by volume	Direct measurement of the composition of the gas stream at the input to the pipeline on a basis recommended by program authorities. Gas analyzers should be calibrated in accordance with manufacturer's specifications.
$Vol._{Gas\ Supplied}$	Total volume of gas (containing primarily CO_2) supplied to the storage site operator, metered at the point of transfer between pipeline (or equivalent) and CO_2 storage site, measured at standard conditions, in year y.	m^3/yr, scf/yr	Continuous measurement of the volume of gas delivered to the CO_2 storage site, where continuous measurement is defined by the program authority.

TABLE 2: Monitoring Parameters *(continued)*

PARAMETER	DESCRIPTION	UNITS	COMMENT
VENTED AND FUGITIVE CO_2 EMISSIONS FROM CO_2 STORAGE IN PRODUCING AND NON-PRODUCING FORMATIONS			
$N_{Blowdown\ j}$	Number of blowdowns (venting events) from specific equipment at the storage site (e.g., compressors, pressure release valves), obtained from blowdown event logs retained by storage site operator.	#	Storage site operator should keep detailed logs of all venting incidents.
$V_{Blowdown\ j}$	Total volume of blowdown equipment chambers for equipment (including pipelines, manifolds and vessels between isolation valves).	m^3, scf	Volume can be estimated based on equipment specifications (pipeline diameters etc.), flow meters, duration of event.
$\%GHG_i$	Concentration of GHG (CO_2 or CH_4) in the injected or produced gas (Volume percent CO_2 or CH_4, expressed as a decimal fraction).	%	Measurements should be taken at a minimum frequency as determined by program authorities. Calibrate gas analyzer at least once per quarter or in accordance with manufacturer's specifications.
$Count_s$	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells in the non-producing formation.	#	Storage site operator should develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities at the storage site.
T_s	Total time in hours that the equipment associated with the each fugitive emission source was operational.	Hours	Estimated based on operational records of downtime at the injection wells, storage site and hydrocarbon production facilities.
$Vol._{Gas\ Sold}$	Volume of natural gas or fuel gas, produced from the formation that CO_2 is being injected into, that is sold to third parties or input into a natural gas pipeline in year y.	m^3, scf	Continuous metering of sales volumes of natural gas, where continuous measurement is defined by the program authority.
$\%\ CO_{2\ Gas\ Sold}$	% CO_2 in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year y.	%	Direct measurement of the composition of the natural gas at the sales meter on an annual basis.

TABLE 2: Monitoring Parameters *(continued)*

PARAMETER	DESCRIPTION	UNITS	COMMENT
$Mass_{Water\ Prod}$	Mass of water produced from the formation that CO2 is being injected into, that is disposed of or otherwise not-re-injected back into the formation.	Metric tons	Monthly reconciliation of water disposal records.
$Mass\ Frac_{CO2\ in\ Water}$	Mass fraction of CO_2 in the water produced from the formation.	-	Conduct lab analysis of composition of produced water as required by the program authority.
$Mass_{Hydrocarbons\ Prod}$	Mass of crude oil and other hydrocarbons produced from the formation that CO_2 is being injected into.	Metric tons	Reconciliation of hydrocarbon sales from facilities associated with the producing formation.
$Mass\ Frac_{CO2\ in\ Oil}$	Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation.	-	Conduct lab analysis of composition of produced water as required by the program authority.
CO_2 TRANSFERRED OFFSITE IN PRODUCING RESERVOIRS			
$Vol_{CO2\_Transfer}$	Volume of produced CO_2 from an enhanced oil or gas operation transferred outside project boundary in each year.	m^3, scf	CCS projects developers deduct from quantified reductions "produced CO_2" that is not reinjected but transferred offsite. Measured at a point to account for total volume not reinjected.
FUGITIVE CO_2 FROM STORAGE TO ATMOSPHERE IN PRODUCING AND NON-PRODUCING FORMATIONS			
CO2Z	Total mass of CO_2 emitted through leakage pathway z to atmosphere in year y.	Metric tons	In the event that leakage from the geologic reservoir to the atmosphere occurs, the mass of CO_2 that has escaped would be estimated based on monitoring and measurements completed as part of the CCS project's MRV plan. Note: Examples of leakage pathways are faults and fractures, not fugitive CO_2 from wells (as calculated according to Equation 8.3.1).

12. MONITORING GEOLOGIC STORAGE OF CO_2

Monitoring CO_2 storage operations provides the basis to substantiate assertions that injected CO_2 remains permanently sequestered from the atmosphere. For CCS projects that seek recognition for GHG reductions a monitoring program for CO_2 storage sites would, at a minimum, include components to validate that the risk of CO_2 leakage from the geologic reservoir to the atmosphere is minimized, and, if a leak is detected, that corrective action measures are available to remediate occurrences of leakage. In the event that CO_2 escapes from the geologic storage complex and results in emissions to the atmosphere, project developers would also quantify total emissions to the atmosphere according to Equation 9.

However, providing instructions to project developers on the type of monitoring systems to deploy to track injected CO_2 in the subsurface is outside the scope of this document. Because of the complexity and uniqueness of each reservoir project developers would determine the subsurface CO_2 monitoring regime according to site-specific characteristics.

Therefore, this section provides a brief overview of monitoring activities that would occur during typical stages of CO_2 storage and a table of resource for developing CO_2 storage monitoring programs.

State and federal regulations cover all phases of CO_2 injection and storage operations to protect human health and safety, property, and groundwater and other environmental resources. Additional aspects of a monitoring program applicable to accounting for atmospheric emissions from the CO_2 storage site would augment the requirements from state and federal agencies, in compliance with the appropriate program authority.

12.1 Overview of CO_2 Storage Monitoring

Generally, project developers create CO_2 storage site monitoring plans that include phases, such as (1) pre-operational monitoring, (2) operational monitoring, and (3) post-injection and closure monitoring.

The pre-operational monitoring phase forms the basis for the site selection process and supports the design of the monitoring plan for the operational phase, reflecting the assessed risks and baseline data. It consists of the following components:

- Site characterization
- Reservoir modeling
- Risk assessment
- Baseline monitoring

BOX 5: Monitoring CO_2 Storage to Assert Permanent CO_2 Sequestration Under EPA's UIC and GHGRP

A monitoring program for CO_2 injection and storage operations—located at either non-producing formations or enhanced oil and gas recovery sites—that satisfies its respective Underground Injection Control (UIC) permit requirements and Subpart RR of EPA's Greenhouse Gas Reporting Program (GHGRP) could provide the basis for a reasonable and sufficient assurance that CO_2 is permanently stored.

Enhanced oil and gas operators with Class II permits may choose to report CO_2 injection data to the EPA under Subpart UU—Injection of Carbon Dioxide—instead of Subpart RR. If the CO_2 storage component of a CCS project takes place at an enhanced oil and gas recovery operation, which does not have a monitoring, reporting and verification program consistent with Subpart RR, then project developers should create a monitoring regime that provides an equivalent level of confidence regarding the effectiveness of CO_2 storage.

Ultimately, all CO_2 storage sites, including enhanced oil and gas recovery operations, have the responsibility to manage and monitor the facility in a manner consistent with the objective to permanently sequester injected CO_2 from the atmosphere, regardless of its injection well class or whether it reports to the EPA's GHGRP under Subpart RR or UU.

Appendix B provides an overview of the EPA's UIC and Greenhouse Gas Reporting Program.

The operational monitoring phase, for the purposes of accounting for emissions reductions from CCS projects, involves implementing systems to measure operational parameters, track the CO_2 plume and monitor for leakage via the potential pathways identified in the pre-operational phase. In the event that leakage does occur during the operational phase, the project developer must estimate the quantity of CO_2 that has leaked from the storage complex to the atmosphere in order to quantify the release, as incorporated in the quantification of the overall CCS project's GHG emissions reduction (Sections 9.2.3 or 9.2.4).

CO_2 storage site operators will implement a combination of surface and subsurface monitoring techniques to monitor parameters consistent with baseline information. Additionally, the program will include testing to confirm the mechanical integrity of the injection well(s). Operational monitoring would include the following components:

- Surface monitoring to detect and help quantify any leakage from pathways such as wells, faults and fractures that could result in a release to the atmosphere without prior detection in a lower monitoring zone, or to aid in the identification of suspected leaks based on monitoring in lower zones.
- Sub-surface monitoring to establish the behaviour of the CO_2 plume in the subsurface, receive early warning about any possible migration along pathways to the surface, and inform any further monitoring or quantification action if needed.
- Mechanical integrity testing to establish confidence in the ability of wells to prevent unwanted fluid migration, and to trigger additional monitoring or quantification efforts if a leak is suspected.

The post-injection and closure monitoring phase is designed based on the information collected or modelled during the operational monitoring phase. It would consist of a monitoring phase immediately following the cessation of injection up to the point at which the site is closed, followed by a post-closure monitoring phase. The conditions for the site closure as well as the duration of the post-closure monitoring phase would be set out by the relevant program authority, consistent with the objective to ensure the permanent sequestration of injected CO_2 from the atmosphere. Site closure should be based on site-specific and performance based measures.

Should CO_2 leakage to the atmosphere from the geologic storage complex occur after injection has ceased, other mechanisms may be required to account for GHG emissions associated with CO_2 leakage. It is expected that the program authority with oversight for the program or registration of emission reductions would provide additional guidance on how to address CO_2 leaks and a reversal of GHG emissions reductions (e.g., a release of previously stored emissions). Potential mechanisms are discussed in Appendix A.

12.2 CO_2 Storage Monitoring Best-Practice Manuals and Guidance Documents

The following table presents best-practice manuals and guidance documents to monitor geologic CO_2 storage sites. Its purpose is to assist with development of CO_2 monitoring strategies and programs; however, it is not a comprehensive list and project developers should continue to keep current on new resources.

TABLE 3: CO_2 Storage Monitoring Best-Practice Manuals and Guidance Documents

1)	*U.S. Department of Energy, National Energy Technology Laboratory* "Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations" (2009) www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf
2)	*U.S. Environmental Protection Agency* "General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU Greenhouse Gas Reporting Program" (Chapter 4 & 5) (2010) www.epa.gov/climatechange/emissions/downloads10/Subpart-RR-UU_TSD.pdf
3)	*Lawrence Berkeley National Lab* "GEO-SEQ Best Practices Manual: Geologic Carbon Dioxide Sequestration: Site Evaluation to Implementation" (2004) www.escholarship.org/uc/item/27k6d70j.pdf
4)	*Canadian Standards Association* "Geological Storage of Carbon Dioxide, CSA Z741" (in press) www.csa.ca/cm/ca/en/standards/products/climate-change
5)	*European Commission* "Monitoring and Reporting Guidelines for Greenhouse Gas Emissions from the Capture, Transport and Geological Storage of Carbon Dioxide" (2010) ec.europa.eu/clima/documentation/ets/monitoring_monitoring_en.htm
6)	*European Commission* "Guidance Document 2: Characterisation of the Storage Complex, CO_2 Stream Composition, Monitoring and Corrective Measures" (2011) ec.europa.eu/clima/policies/lowcarbon/docs/gd2_en.pdf
7)	*UK Department of Business Enterprise and Regulatory Reform* "CO_2 Capture and Storage in the EU Emissions Trading Scheme—Monitoring and Reporting Guidelines for Inclusion Via Article 24 of the EU ETS Directive" (2007) www.ieaghg.org/docs/General_Docs/Best%20Practice%20Docs/2007BERR.pdf
8)	*International Energy Agency Greenhouse Gas R&D Programme* "Interactive Design of Monitoring Programmes for the Geological Storage of CO_2" (2009) www.ieaghg.org/co2tool_v2.2.2_product_joomla/index.php

TABLE 3: CO_2 Storage Monitoring Best-Practice Manuals and Guidance Documents *(continued)*

9)	*International Energy Agency Greenhouse Gas R&D Programme* "Overview of Monitoring Techniques and Protocols for Geologic Storage Projects" (2004) www.co2captureandstorage.info/co2tool_v2.2.1/introduction.html
10)	*Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories* "Chapter 5: Carbon Dioxide Transport, Injection and Geological Storage, Volume 2 – Energy." (2006) www.ipcc-nggip.iges.or.jp/public/2006gl/index.html
11)	*British Geological Survey* "Best Practice for the Storage of CO_2 in Saline Aquifers, Observations and Guidelines from the SACS and CO2STORE Projects" (2008) www.bgs.ac.uk/downloads/start.cfm?id=1520
12)	*Det Norske Veritas* "CO2QUALSTORE: Guideline for Selection and Qualification of Sites and Projects for Geological Storage of CO_2" (2010) "CO2WELLS: Guideline for the Risk Management of Existing Wells at CO_2 Geological Storage Sites" (2011) www.dnv.com/industry/energy/segments/carbon_capture_storage/recommended_practice_guidelines/co2qual-store_co2wells/index.asp
13)	*World Resources Institute* "CCS guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage" (2008) www.wri.org/publication/ccs-guidelines
14)	CO_2 Capture Project "A Technical Basis for Carbon Dioxide Storage" (2009) www.co2captureproject.org/allresults.php?pubcategory=storage

APPENDIX A

ADDITIONAL GHG ACCOUNTING-RELATED ISSUES FOR CCS PROJECTS

In addition to providing quantification methods to determine GHG reductions and presenting approaches to monitor CCS projects, program authorities with GHG reporting programs and registries will need to address policy-related issues in order to develop coherent systems and protocols to recognize GHG reductions from CCS projects. While there are number of specific issues that will need to be addressed in any GHG program that seeks to incentive GHG reductions (including eligibility requirements, roles and responsibilities of project participants, and third-party verification procedures), this appendix discusses four policy issues that pertain specifically to CCS projects and which could significantly impact CCS projects:

- Ownership of the CCS project's GHG reductions;
- Additionality;
- Subsurface ownership of pore space into which the project developer will inject CO_2; and
- Permanence and liability for reversals in GHG emissions reductions from CO_2 storage sites.

Ultimately, the resolution of these issues will result from consultations between project developers, program administrators, and the public.

OWNERSHIP OF GHG REDUCTIONS

For CCS projects with multiple entities involved in capturing, transporting, and storing CO_2—with each potentially having separate legal responsibilities over the $CO_{2,}$ confusion over ownership of the emissions reductions from the project could occur as control of the CO_2 changes hands. This has significant importance if a CCS project developer seeks recognition for the emissions reductions from its projects, especially if CCS were to become an eligible project category for creating GHG offset credits.

While contractual negotiations will address many ownership claims, program authorities may want to consider designating ownership of the CCS project's GHG reductions to the entity that initially creates the CO_2 (e.g., the owner of an electricity generating facility, if that is the source of CO_2 for the CCS project). To the extent that capturing and sequestering CO_2 has value, this would help clarify chain of custody negotiations between project participants. Such an approach would align with common practice that assigns responsibility for emissions reporting and control to the owner of the emissions source.

It is also useful to distinguish between ownership of a CCS project's GHG reductions and responsibility under other regulatory programs for controlling and reporting CO_2 emissions along the capture, transport, or injection and storage segments—e.g., the EPA's Underground Injection Control and/or Greenhouse Gas Reporting Programs. For example, a company holding a Class II or VI permit has "corrective action" and liability obligations associated with the CO_2 it injects into geologic reservoirs. Responsibility for the injected CO_2, however, does not necessarily mean ownership of the emissions reductions from the CCS project. Project participants should clearly communicate through contractual arrangements ownership of the reductions.

ADDITIONALITY

In addition to providing rules regarding the ownership of a GHG emissions reduction, program administrators may also require an assessment of the additionality of a project. Additionality is concept that refers to whether the GHG reductions associated with the project would have occurred in the absence of a policy incentive that facilitates the implementation of the project. It is often used as a project evaluation screen to assess if the emissions reductions from a project exceed business-as-usual. For instance, if the value of an offset credit is instrumental in bringing a GHG project to fruition, then it would likely be considered to pass the "additionality" test.

Conversely, if a project is implemented because it must comply with a law or regulation it is usually not considered additional. In other words, the project would have happened without the value stream provided by the offset credit.

Additionality is an important concept because policymakers do not aim to create incentive mechanisms to reward projects that would have happened even without the incentive. This is especially true with programs that allow GHG reductions from sources not covered by the program to be used as CO_2 offset credits. In a GHG market-based program that allows offset credits, these credits could be traded and used by a different entity as if they had made the emission reduction themselves. As such, the offset credit must represent a reduction beyond what would have occurred "anyway," or there is no real environmental benefit.

Determining a project's additionality is an essential but approximate process and current offset programs utilize a variety of procedures and tests to determine the additionality of a project. A key component of additionality determinations is identifying a realistic baseline that forecasts emission levels in the project's absence. Generally, two approaches are used to determine an appropriate baseline, which should result in a reasonable reference case against which to compare project emissions (and determine GHG reductions) as well as inform the additionality determination.

1. Project-specific. The project developer self-determines the baseline, according to a method approved by a program authority.

   The project-specific approach is often considered a bottoms-up method, in which individual project proponents have the responsibility to demonstrate that the approach to determine the baseline for their particular project is valid. Obtaining approval for a proposed "new methodology" under the Clean Development Mechanism (CDM) is an example of a project-specific approach to determine baselines.[30]

2. Programmatic. A program authority defines or approves a baseline for all types or a set of CCS projects that participate in its program and meet its eligibility requirements.

   The programmatic approach follows a top-down method. In this case, the program authority sets the baseline for all CCS project, for example, within its jurisdiction. Examples of a programmatic approach to define baselines include performance standards—as in the protocols from the Climate Action Reserve[31]—and sector-level baselines.[32]

Project-Specific Baseline. Under the project-specific approach, the project proponent is responsible for executing a multi-step process to determine the baseline. The World Resources Institute (WRI) / World Business Council for Sustainable Development (WBCSD) GHG Protocol for Project Accounting (Project Protocol), provides a thorough description of the approach.

Broadly represented, the approach from WRI/WBCSD involves

- Identifying baseline candidates, which are alternatives to the proposed project that could feasibly be implemented in its place, given certain conditions; and
- Evaluating baseline candidates and the proposed project relative to barriers to implementation and determine the baseline scenario that applies to the project.

Barriers to implementing potential baseline candidates could include financial hurdles and/or technological challenges, for instance. Out of the field of baseline candidates, the project-specific approach should yield an identifiable baseline scenario—different from the proposed project– based on the relative impact of the barriers.[33]

In addition to the WRI/WBCSD Project Protocol, CDM includes a combined to tool to identify the baseline scenario demonstrate additionality.[34]

Programmatic Baseline. [35] Under the programmatic approach, relevant sector-level conditions and practices are evaluated to establish a standardized baseline and define additionality thresholds, usually applicable to multiple projects that meet specified applicability requirements (whereas the project-specific approach most often relates to a particular project).

A programmatic baseline is defined by a program authority, which could either approve a proposed program-wide baseline from a project proponent or create one itself. It could be expressed as an emission rate, a type of technology for the relevant sector, or common practice, among other ways.

An example of a top-down approach for setting programmatic baselines is the Regional Greenhouse Gas Initiative's (RGGI) eligible offset categories. These include

- Landfill methane capture and destruction,
- Reduction in emissions of sulfur hexafluoride (SF_6) in the electric power sector,

- Sequestration of carbon due to afforestation,
- Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency in the building sector, and
- Avoided methane emissions from agricultural manure management operations.[36]

Generally, programmatic baselines have broader applicability than project-specific baselines. A program that uses programmatic baseline, however, will be less flexible given that the predominant practices for the relevant sector are standardized and applied across the sector, regardless of the differences between projects.

PORE SPACE OWNERSHIP

Another policy element that requires determination is the issue of subsurface pore space ownership. Resolving who owns the pore space into which the CO_2 is injected is an area of significant interest that could potentially impact the liabilities associated with CO_2 storage, should leakage to the atmosphere occur. In the U.S., property rights, including pore space ownership, are being addressed through state law and regulation. Indeed, several states have taken steps to settle pore space ownership issues by declaring that the surface owner has ownership rights to subsurface pore space.[37]

The Interstate Oil and Gas Compact Commission's (IOGCC) "Legal and Regulatory Guide for States and Provinces" observes that injecting CO_2 into various geologic formations for storage purposes, such as oil and gas reservoirs and saline formations, is governed by multiple surface and mineral interests. For example, mineral developers may be granted rights to extract resources under the terms of their mineral interests, while the ownership over geologic formations may be held by the party entitled to surface interests related to the land over the formation. IOGCC proposes designating the surface owner "with the right to lease pore space for storage, while protecting other stakeholders from potential damage attributable to sequestration activities."[38]

In terms of GHG accounting, for CCS projects to safely and permanently sequester CO_2 from the atmosphere CCS project developers must obtain rights to injection zone pore space prior to commencing CO_2 injection. Furthermore, program authorities should also consider implementing rules that prevent changes in the use of pore space once it has been used for CO_2 storage. This might happen for example should there be a desire to convert CO_2 storage into natural gas storage, which could displace CO_2, and potentially cause a release to the atmosphere.

PERMANENCE AND LIABILITY FOR REVERSALS IN GHG EMISSIONS REDUCTIONS

Program administrators may also require that CCS project developers demonstrate a level of assurance that the CO_2 capture and stored is permanently sequestered underground. However, defining what constitutes "permanent" in a way that (1) provides confidence that the selection, management, and closure of CO_2 storage sites will perform as an effective climate mitigation solution, and (2) enables CO_2 storage operators to practically demonstrate their storage complex meets the definition, is currently an unsettled issue.

Ultimately, identifying a threshold that signifies an acceptable minimum level of CO_2 retention for geologic reservoirs—i.e., a CO_2 storage standard, expressed as a retention rate—could help serve as a screen to select suitable CO_2 storage sites. It could also be used as the basis for defining what permanence means in terms of CCS project accounting and could help in the determination of rules around project liability.

Liability concerns for CCS projects mainly focus on CO_2 storage issues and identifying responsible parties to manage containment risk for decades after CO_2 injection has ceased. In terms of GHG emissions accounting, liability over failure to permanently sequester injected CO_2 means taking responsibility for leaks and reversals of GHG emissions reductions. All sequestration projects—including geologic and terrestrial—have the potential for reversals because the GHG reductions are not the result of avoiding the production of the GHG emissions (i.e., replacing coal-fired with wind-powered electricity). Instead, CCS prevents produced CO_2 from entering the atmosphere by routing it through a capture, transport, and storage system. A GHG reversal in the CCS context would occur when a geologic storage complex fails to sufficiently contain injected CO_2, allowing it to (eventually) enter the atmosphere. It is important to point out, though, that properly selected, operated and closed, sites are generally expected to permanently contain injected CO_2 and project monitoring should provide further assurance.

Liability, as it relates to CCS, can be expressed as responsibility for:

1. Damages to human health, environment and property, and
2. Reversals in claimed GHG emissions reductions due to failure to contain injected CO_2.

In some jurisdictions, the transfer of liability may ultimately be conveyed from the injection site operator to the State with periodic monitoring required to ensure stability of the injected CO_2 over a long-term period. If long-term liability over the CCS project is eventually transferred from the project operator to the state, the CCS operator may be required to make a financial contribution to the program authority. At a minimum, the financial contribution would likely cover the anticipated cost of monitoring for a period until the risk of leakage is deemed minimal.

While the CCS Accounting Framework does not provide specific recommendations to ensure permanent CO_2 storage or recommend mechanisms that address liability for reversals in GHG emissions reductions, it provides the following key considerations to help inform program authorities develop rules and procedures to address these matters.

- In the case of CCS, permanence is ultimately a function of (1) the capability of a geologic storage reservoir to accept and retain injected CO_2, and (2) the actions of the CO_2 storage site owner/operator regarding site selection, operation, and closure.
- The general expectation among experts in the CCS community is that CO_2 injected into properly sited and managed reservoirs should remain permanently sequestered from the atmosphere, and if CO_2 emissions do occur then the likelihood of leakage is highest during injection, and through wells and faults.[39]
- In the event that problems arise with the CO_2 storage complex, technical solutions exist to implement corrective action measures to mitigate certain situations that could lead to leaks to the atmosphere.
- The Intergovernmental Panel on Climate Change's (IPCC) Special Report on Carbon Capture and Storage (SRCCS) states that properly selected and managed storage sites should likely retain at least 99 percent of injected CO_2 over 1000 years.[40]
- While it is incorrect to interpret IPCC to conclude that a retention rate of 99 percent over 100 years represents a recommended "performance standard" to which all CO_2 storage sites must meet on an on-going basis,[41] it could be used as a "design standard" and serve to screen candidate CO_2 storage sites.
- Along with monitoring technologies to validate and update the modeled behaviour of injected CO_2, corrective action procedures to mitigate potential escapes from the CO_2 storage complex, and a mechanism to cover liabilities in the event of non-performance, a CO_2 storage "design standard" could be used as a starting point to satisfy the permanence criterion—i.e., to substantiate claims that a CCS project has yielded permanent GHG emissions reductions.
- Within the U.S., in the absence of a federal standard for individual storage sites, states have developed their own. For example, Texas requires a reasonable expectation that at least 99 percent of the carbon dioxide sequestered will remain sequestered for at least 1,000 years.[42] And the State of Washington defines permanence for CO_2 sequestration as "the retention of greenhouse gases in a containment system… that creates a high degree of confidence that substantially ninety-nine percent of the greenhouse gases will remain contained for at least one thousand years."[43] Other states have also explored options to define a performance standard for CCS sites.[44]
- The permitting process for the EPA's UIC program obligates storage site operators to sufficiently contain injected CO_2 in a manner that prevents leaks from the storage complex, which could contaminate underground sources of drinking water.[45]
- The requirement to contain injected CO_2 that underpins the UIC program and protects USDW is consistent with the prerequisite for CCS that injected CO_2 remain permanently sequestered from the atmosphere.
- Policy options exist to address damages associated with reversals in emissions reductions from CCS projects. Program authorities could use the following four options for managing the risk associated with leaks from the CO_2 storage formation to the atmosphere:
    1. <u>An assurance factor</u>: A percentage of all tons credited are discounted according to a coefficient that takes into account the probability of a reversal occurring over a set period of time for a defined region. The discounted tons are handed over to the regulatory authority which holds them indefinitely.

2. Holdbacks/Buffer Pools: A percentage of all tons credited are held in a reserve account. In the event of leakage, debit is measured and reported, verified, and reconciled by the account. The tons held in the reserve can be returned to the project operator through periodic review and recalibration of the size of the reserve.
3. Private insurance: The project developer purchases private insurance. Insurance premiums would be paid by the project developer to the insurance company, and, in the event of CO_2 leakage to the atmosphere, the insurance company would cover obligations to compensate for reversals in GHG emissions reductions (e.g., purchase allowances or credits).
4. Bonding: The project developer posts a bond as assurance for performance. It would be acquired on an up-front basis and forfeited if CO_2 leakage to the atmosphere occurs; bond proceeds would be used to cover obligations to compensate for reversals in emissions reductions.

APPENDIX B

THE U.S. EPA'S UNDERGROUND INJECTION CONTROL AND GREENHOUSE GAS REPORTING PROGRAMS

The U.S. EPA's Underground Injection Control (UIC) Program and Greenhouse Gas Reporting Program (GHGRP) include requirements relevant to accounting for GHG reductions associated with CCS projects.

1. THE UNDERGROUND INJECTION CONTROL PROGRAM

EPA's UIC Program promulgated minimum Federal requirements for underground injection to ensure protection of underground sources of drinking water (USDWs) under the authority of the Safe Drinking Water Act. EPA distinguishes six injection well classes (Classes I through VI), depending on the type of fluid injected underground and the purpose of the activity.[46] UIC Program implementation is conducted by either EPA or States that have applied for and received primary enforcement responsibility (primacy).[47]

Class VI and Class II requirements apply to CO_2 injection for purposes of geologic sequestration and enhanced oil and gas recovery, respectively. Rules for Class VI wells include permitting, site characterization, area of review delineation, well construction and operation, monitoring, well plugging, post-injection site care and site closure.[48] Similarly, EPA provides minimum requirements for Class II operations, including rules for well construction, operating, monitoring, reporting, plugging, and closure.[49] The intent of a Class II operation is for enhanced oil and gas operations and not necessarily to permanently sequester injected CO_2; if it meets specific conditions defined in EPA's rules for Class VI wells it must transition from a Class II to a Class VI permit.[50]

Because Class VI wells are designed for projects that handle very large volumes of CO_2 injected into relatively unfamiliar geologic formations (e.g., saline aquifers), EPA produced more demanding regulations than the Class II rules, which apply to well known and tested oil and gas fields. A UIC Class VI permit involves additional site characterization, computational modeling, well testing, project monitoring, and other requirements.

Both Class VI and Class II requirements are designed to contain injected CO_2 within their respective storage formations, and permits issued from either the EPA or State agencies for both well classes obligate CO_2 injection facilities to operate their sites in a manner that will prevent CO_2 (and other formation fluids) from migrating out of the geologic containment system into drinking water aquifers.[51] Receipt of a UIC permit to commence CO_2 injection means the site operator has demonstrated to the appropriate regulatory authority that it's operation should not result in CO_2 escaping the containment complex and enter a drinking water aquifer.

While neither Class VI nor Class II requirements address accounting for emissions to the atmosphere, effective containment to satisfy UIC permits should, for the vast majority of cases, result in CO_2 sequestration from the atmosphere.[52] Therefore, along with CO_2 storage monitoring (discussed below), Class II and Class VI permitting should support a GHG program-specific process to ensure that injected CO_2 associated with CCS projects remains permanently sequestered from the atmosphere.

2. THE GREENHOUSE GAS REPORTING PROGRAM

The EPA's GHGRP directly aligns with the objectives of the CCS Accounting Framework, as the purpose of the program is to provide a platform to account for and report GHG emissions from participating facilities.[53] Several subparts of the GHGRP pertain to the CCS Accounting Framework, as CO_2 capture would occur at facilities for which the GHGRP has industry-specific GHG accounting rules and procedures (e.g., power generation, Subpart D; hydrogen production, Subpart P; petroleum and natural gas systems, Subpart W).

However, the most relevant components of the GHGRP to GHG accounting for CCS projects are Subpart RR—Geologic Sequestration of Carbon Dioxide—and Subpart PP—Suppliers of Carbon Dioxide. Subpart RR applies to all CO_2 sequestration sites, including wells permitted under Class VI as well as Class II sites that choose to classify their CO_2 enhanced oil and gas injection operation as a CO_2 sequestration activity.[54] Subpart PP applies to suppliers of CO_2. With respect to CCS projects, Subpart PP would affect companies that capture CO_2 for the sake of geologic sequestration.[55]

Project monitoring for CO_2 injection and storage under Subpart RR to EPA's GHG reporting program requires the development of a monitoring, reporting, and verification (MRV) plan that includes, at a minimum the following components:

- Delineation of monitoring areas,
- Identification and assessment of potential surface leakage pathways,
- Strategy for detecting and quantifying surface leakage of CO_2 if leakage occurs,
- Approach for establishing the expected baselines, and
- Summary of considerations for calculating site-specific variables for the mass balance equation.[56]

CO_2 storage monitoring under EPA's GHGRP Subpart RR complements and builds on UIC permit requirements. Fulfilling the Class VI requirements can provide the basis for the MRV plan submitted to EPA for GHG reporting purposes under Subpart RR.[57] A Class II well designated as a geologic sequestration activity would not necessarily have to change well class, but would augment its permitted MRV procedures for the UIC program to comply with requirements under EPA's GHGRP Subpart RR.

APPENDIX C

SUMMARY TABLES FOR BASELINE AND PROJECT EMISSIONS CALCULATIONS

TABLE C.1: Overview of Projection-based and Standards-based Baselines Calculation Procedures

TYPE OF BASELINE	GHGS	DESCRIPTION	MONITORING CONSIDERATIONS
Projection Based Baseline	CO_2 To be conservative, CH_4 and N_2O excluded from the baseline quantification.	Section 9.1.1, Equation 2.0. Baseline emissions for a Projection-based baseline are calculated by measuring total CO_2 produced by the primary process in the actual project. In certain cases, the amount of CO_2 generated in by the project (and used to calculate baseline emissions under a Projection-based baseline) may need to be adjusted to account for the incremental CO_2 generated to meet the energy penalty required to capture CO_2, if the energy required to operate the CO_2 capture process equipment is met through electricity or thermal energy generated from the same process as that produces the captured CO_2. Quantify the incremental mass of CO_2 generated at the capture site (to adjust the measured CO_2 value and properly account for the "parasitic load" from the CO_2 capture equipment) by deducting the CO_2 emissions from using steam to regenerate the CO_2 absorber according to facility engineering design information or from metered steam usage and steam conversion factors appropriate for the facility.	Total volume of CO_2 produced by the actual project's primary process. Steam used to meet the parasitic loads from the CO_2 capture and compression equipment, if necessary.
Standards Based Baseline	CO_2 To be conservative, CH_4 and N_2O excluded from the baseline quantification.	Section 9.1.2, Equation 3.0. The Standards-based baseline is calculated by multiplying an emissions intensity metric or "performance standard," expressed as (tCO_2e/unit of output), by the actual output of the project's primary process (e.g., MWh for power generation, MMscf processed for natural gas production). As ultimately approved by the program authority, the level of CO_2 production in the numerator of the metric would be based on the type of facility creating the captured CO_2. Procedures for collecting data from the actual project to determine the "output" value used to calculate baseline emissions should be set to maintain functional equivalence between baseline emissions and project emissions and ensure that the quantified emissions reductions appropriately represents the impact of the CCS project.	Measurement of "output" based on the type of primary process. Output should be measured to account for the total output from the primary process that would have occurred in the absence of the project.

TABLE C.2: Overview of Project Calculation Procedures

CCS SEGMENT	EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
CO_2 Capture	Total Capture Emissions CO_2; CH_4; N_2O	Section 9.2.1, Equation 5.0. Total Project Emissions from CO_2 capture processes, including direct and indirect emissions.	N/A
	Non-captured CO_2 from the primary process Vented & Fugitive CO_2	Section 9.2.1, Equations 5.1; 5.1.A, 5.1.B, 5.1.C CO_2 Emissions from the primary process, which has not been captured by the CO_2 capture equipment and transferred to the transport (pipeline) segment. Non-captured CO_2 encapsulates CO_2 emitted to the atmosphere from the capture site via vent stacks at the primary process and via venting or fugitive releases from other equipment at the capture and compression facilities. This quantity of CO_2 is equal to the difference between the total quantity of CO_2 produced and the quantity of CO_2 input into the pipeline.	Total volume of gas produced from the primary process, and captured and input into the pipeline
	Stationary Combustion CO_2; CH_4; N_2O	Section 9.2.1, Equation 5.1.B & 5.2 A fuel-based calculation method, which applies to 1) primary process CH_4 and N_2O emissions for projects that generate CO_2 for capture through combustion, and 2) equipment used to capture and compress CO_2, including cogeneration units, boilers, heaters, engines, turbines, flares, etc, which are owned and controlled by the capture site located at all capture sites.	Annual amount of fossil fuel burned, by fuel type
	Electricity and Thermal Energy Use (if required) CO_2; CH_4; N_2O	Section 9.2.1, Equation 5.3, 5.3.A, 5.3.B, 5.3.C Indirect (Scope 2) emissions from purchased and consumed electricity and thermal energy (steam) used to operate the CO_2 capture and compression equipment. Electricity may be used to operate the CO_2 compressors, dehydration units, refrigeration units, circulation pumps, fans, air separation units and a variety of other equipment. Purchased steam may be used for various purposes, including regeneration of the CO_2-rich absorbent used for a post-combustion capture configuration.	Total quantities of electricity and steam used to operate the CO_2 capture equipment

TABLE C.2: Overview of Project Calculation Procedures *(continued)*

CCS SEGMENT	EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
CO_2 Transport	Total Transport Emissions CO_2; CH_4; N_2O	Section 9.2.2, Equation 6.0. Total Project Emissions from CO_2 transport, including vented, fugitive, stationary combustion, and purchased and consumed electricity.	N/A
	Stationary Combustion CO_2; CH_4; N_2O	Section 9.2.2, Equation 6.1. Emissions from fossil fuel combustion to operate equipment used to transport CO_2 to the storage site. For some projects, additional compression may be required along the pipeline or at an interconnection with a pipeline that is operated at a higher pressure. A variety of stationary combustion equipment may be used to inspect, maintain and operate the CO_2 pipeline. Stationary combustion equipment could include engines, turbines and heaters etc. that are under the direct control of the CO_2 pipeline operator.	Annual amount of fossil fuel burned, by fuel type
	Vented & Fugitive CO_2	Section 9.2.2, Equations 6.2; 6.2.A, 6.2.B Vented and fugitive emissions are calculated according to a mass balance approach using metered values at the point of transfer at the capture site and at the storage site. Venting and fugitive releases during CO_2 transportation. Fugitive emissions may arise from leakage of CO_2 from equipment such as flanges, valves and flow meters. Emissions could also arise from compressor seal vents or pressure release valves. Emissions could also be calculated according to an event-based approach for vented emissions and a component-count method for fugitive emissions. See Vented & Fugitive emissions for storage in non-producing reservoirs.	Metered quantities of CO_2 input into the pipeline and delivered to storage site
	Electricity Use (if required) CO_2; CH_4; N_2O	Section 9.2.2, Equation 6.3. Indirect emissions from electricity used to operate the CO_2 transport infrastructure. In some CCS project configurations, electric-drive compressors may be used for supplemental compression along the CO_2 pipeline, where grid connectivity exists.	Metered quantity of electricity used to operate the CO_2 transport equipment

TABLE C.2: Overview of Project Calculation Procedures *(continued)*

CCS SEGMENT	EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
CO_2 Storage—Non-Producing Formation	Total Storage Emissions—Non-Producing Formations CO_2; CH_4; N_2O	Section 9.2.3, Equation 7.0. Total Project Emissions from CO_2 storage in non-producing formations (e.g., saline aquifers), including stationary combustion, vented, fugitive, and electricity consumption emissions.	N/A
	Stationary Combustion CO_2; CH_4; N_2O	Section 9.2.3, Equation 7.1 Emissions from fossil fuel combustion to operate equipment used to store CO_2 in non-producing formations. A variety of stationary combustion equipment may be used to inspect, maintain and operate the CO_2 injection wells and storage facilities. Stationary combustion equipment could include engines, generators, and heaters etc. that are under the direct control of the CO_2 storage site operator.	Annual amount of fossil fuel burned, by fuel type
	Vented CO_2	Section 9.2.3, Equation 7.2. Emissions from CO_2 venting at the storage site—e.g., the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells. Planned venting (e.g., blowdowns) may occur during shutdowns and maintenance work, while unplanned venting (e.g., blowouts) may occur during process upsets. The amount of CO_2 vented would be determined based on the number of events and the volume of gas contained within the equipment.	Number of venting events; volume of CO_2 per event.
	Fugitive (excluding CO_2 emissions from geologic reservoir to atmosphere) CO_2	Section 9.2.3, Equation 7.3. Fugitive emissions calculated according to a component count method. Fugitive emissions at the storage site are unintended CO_2 leaks from equipment at the injection wells and other surface facilities, located between the transfer meter at the pipeline and the injection wells. Calculated based on a component count method.	Component count of fugitive emission sources; hours of operation for equipment
	Electricity Use (if required) CO_2; CH_4; N_2O	Section 9.2.3, Equation 7.4. Indirect emissions from electricity use to support CO_2 storage operations in non-producing formations. Grid electricity may be used to run equipment at the CO_2 injection wells, monitoring equipment, and other perform other functions.	Metered quantity of electricity used to operate CO_2 storage equipment

TABLE C.2: Overview of Project Calculation Procedures *(continued)*

CCS SEGMENT	EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
CO_2 *Storage—Producing Formation*	Total Storage Emissions—Producing Formations CO_2; CH_4; N_2O	Section 9.2.4, Equation 8.0 Total Project Emissions from CO_2 storage in producing formations (e.g., enhanced oil and gas recovery), including stationary combustion, vented, fugitive, and electricity consumption emissions.	N/A
	Stationary Combustion CO2; CH4; N2O	Section 9.2.4, Equation 8.1. Emissions from fossil fuel combustion to operate equipment used to store CO_2 in the producing formation. Equipment could be used to operate, maintain or inspect the CO_2 injection, storage, processing and recycling facilities and to operate the hydrocarbon production and processing facilities (e.g., gathering systems, oil-water-gas separators). Emissions may occur from combustion of fossil fuels or combustion of hydrocarbons produced from the formation (e.g., in flares).	Annual amount of fossil fuel burned, by fuel type
	Vented CO_2	Section 9.2.4, Equation 8.2 Emissions from CO_2 venting at the storage site—e.g., the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells. Venting may also occur at the production wells, the hydrocarbon production and storage facilities or at the facilities used to process and recycle the produced CO_2 for re-injection into the formation. Planned venting may occur during shutdowns and maintenance work, while unplanned venting may occur during process upsets. The amount of CO_2 vented would be determined based on the number of events and the volume of gas contained within the equipment.	Number of venting events; volume of CO_2 per event.

TABLE C.2: Overview of Project Calculation Procedures *(continued)*

CCS SEGMENT	EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
CO2 Storage—Producing Formation *(continued)*	Fugitive (excluding CO_2 emissions from geologic reservoir to atmosphere) CO_2	Section 9.2.4, Equations 8.3; 8.3.A, 8.3.B Fugitive emissions calculated according to a component count method. Fugitive emissions at the storage site are unintended CO_2 leaks from equipment that occur at the injection wells and other surface facilities, located between the transfer meter at the pipeline and the injection wells, and between the producing wells and hydrocarbon production facilities. Examples of fugitive CO_2 sources for EOR operations include production wells, hydrocarbon production and storage facilities, and equipment used to process and recycle produced CO_2 for re-injection into the formation. Specific locations where CO_2 leaks occur include fittings, flanges, valves, connectors, meters, and headers (which are large pipes that mix the oil stream from multiple wellheads). Fugitive emissions may also result from the release of residual CO_2 entrained or dissolved in produced oil, water or gas that is transferred from the hydrocarbon recovery facilities to downstream users.	Component count of fugitive emission sources; hours of operation for equipment
	Electricity Use CO_2; CH_4; N_2O	Section 9.2.4, Equation 8.4. Indirect emissions from electricity use at the CO_2 storage site in the producing formation. Grid electricity may be used to operate pumps (e.g., for incremental water injection as part of a Water Alternating Gas (WAG) Injection processes), compressors and other equipment at the injection wells and producing wells; at oil and gas gathering, storage and processing facilities (e.g., oil-water-gas separators); or at CO_2 processing, compression, recycling and re-injection facilities. Electric compression may also be used to recycle produced CO_2 and other gases for re-injection into the formation. Electric-drive equipment may also be used to operate vapor recovery units to recover vapors from oil and water tanks, to operate flash gas compressors to increase the pressure of the recovered vapors for recycling, to operate glycol dehydrators and glycol circulation pumps that remove moisture from the produced gas, and to operate other auxiliary equipment such as instrument air compressors and cooling fans.	Metered quantity of electricity used to operate CO_2 storage and recycling equipment

TABLE C.2: Overview of Project Calculation Procedures *(continued)*

CCS SEGMENT	EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
CO_2 Storage—Producing Formation *(continued)*	Transferred CO_2 CO_2	Section 9.2.4, Equation 8.5. While not technically an emission, CO_2 transferred outside the project boundary (i.e., produced-CO_2 from an enhanced oil or gas recovery operation not re-injected but moved offsite) is deducted from claimed emissions reductions. If an enhanced oil and gas recovery site operator intends to move produced-CO_2 between fields, then the boundary would encompasses the multiple fields employed (making sure to account for emissions from all relevant stationary combustion, vented, and fugitive emissions sources).	Volume of produced CO_2 from an enhanced oil or gas operation transferred outside project boundary
CO_2 Storage—Geologic Reservoir	Fugitive CO_2 emissions from the geologic reservoir to the atmosphere	Section 9.2.5, Equation 9. Applicable to CO_2 storage at producing and non-producing reservoirs. For properly selected, operated, and closed CO_2 storage operations, fugitive CO_2 emissions from the geologic reservoir should happen only in extraordinary circumstances. Emissions would be calculated on a site-by-site basis according to according to an approach approved by the program authority. For CO_2 storage producing and non-producing storage facilities, the project monitoring plan would include a strategy for detecting and quantifying any surface CO_2 leakage—i.e., leakage to atmosphere estimated based on monitoring and measurements completed as part of the MRV plan.	Total mass of CO_2 emitted through leakage pathways to atmosphere

POINTS OF CO_2 MEASUREMENT FOR A CCS PROJECT

FIGURE C.1: Points of CO_2 Measurement for the CCS Project[58]

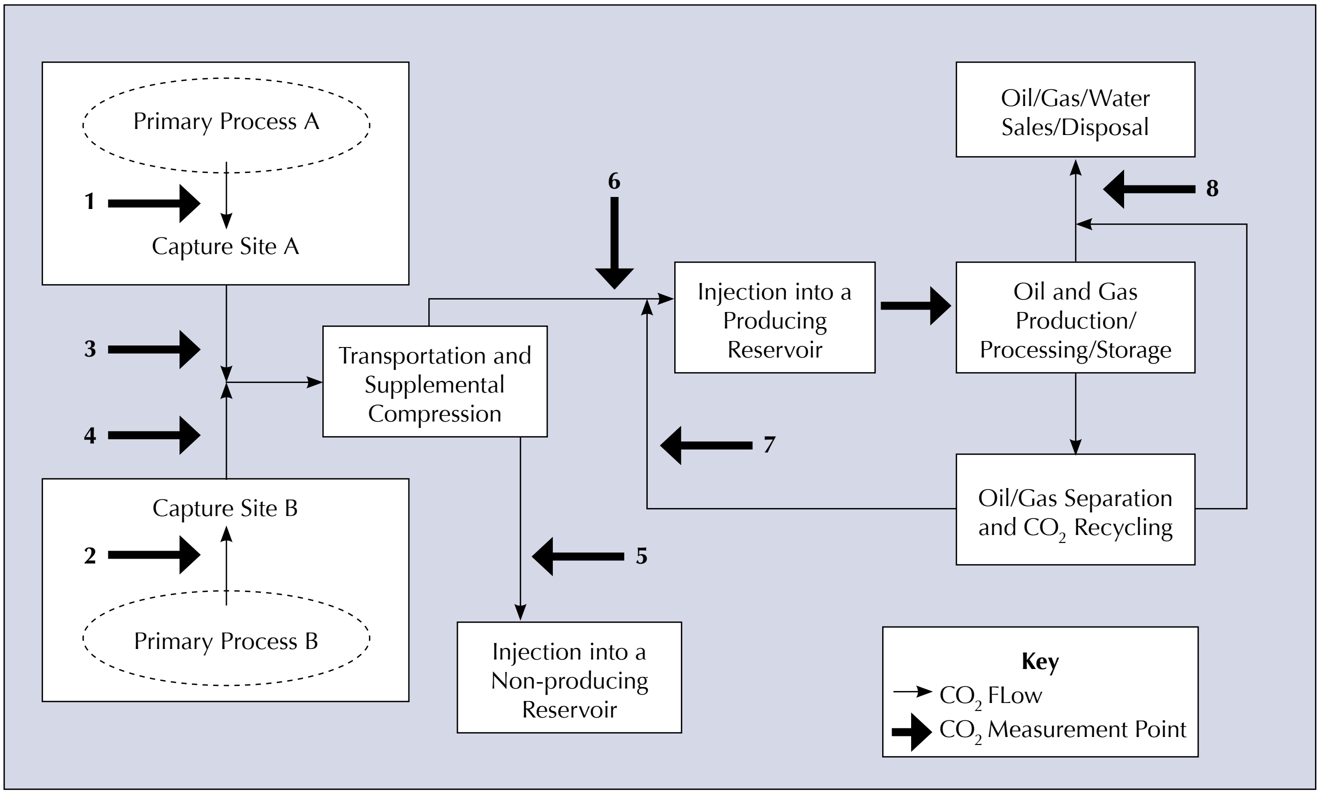


TABLE C.3: Points of CO_2 Measurement for the CCS Project (Associated with Figure C.1)

MEASUREMENT PARAMETER	DESCRIPTION	COMMENT
Flow rate of CO_2 gas stream	**Position 1 & 2.** Flow meters located at the primary process to accurately measure the total amount of CO_2 produced (e.g., measurement of raw flue gas from a combustion process, measurement of total volume of syngas produced from a gasifier upstream of the shift reactor etc.). **Position 3 & 4.** Flow meters located at the input to the CO_2 pipeline such that they are downstream of all capture and compression equipment to account for any fugitive losses or venting. **Position 5 & 6.** Flow meters located at the point of transfer with the pipeline to ensure that a sales quality meter is used. It is also recommended that the quantity of CO_2 injected be measured as close to the injection wellheads to add additional redundancy. **Position 7.** Flow meters located as close as possible to the connection with the main CO_2 pipeline that feeds the injection well(s) to accurately determine the total amount of CO_2 that is recycled. **Position 8.** Flow meters located at a point to measure the total volume of gas produced from the formation and distributed from the storage site (e.g., input into a gas gathering system or sold). This measurement should account for entrained CO_2 in the associated gas/solution gas that has been produced from the formation that CO_2 is being injected into.[59]	Meter readings may need to be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures (e.g., 15°C and 1 atm). Flow meters should be placed a sufficient distance from any obstructions to ensure accurate flow measurements. Flow meters should be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer. Continuous measurement of the gas flow rate, where continuous measurement is commonly defined as one measurement every 15 minutes or less.
Concentration of CO_2 in gas stream	**Position 1-8.** Perform gas analysis through laboratory analysis or on-line gas chromatograph or other gas analyzer.	Measurements should be taken at a minimum frequency of once per month. Gas analyzers should be calibrated at least once per quarter or in accordance with manufacturer's specifications.

APPENDIX D

SUPPLEMENTAL QUANTIFICATION METHODS

This appendix provides information on supplemental quantification methods that may be applied to perform CO_2 mass balance calculations, to calculate GHG emissions from electricity usage, to calculate GHG emissions from stationary combustion from fuel use and in situations where a flare is used. Additional guidance on selecting emission factors for fugitive emissions at CO_2 injection, storage facilities and at hydrocarbon production facilities is also provided.

ADDITIONAL GUIDANCE ON PERFORMING CO_2 MASS BALANCES USING VOLUME OR MASS FLOW MEASUREMENTS

The mass balance equations presented in this methodology rely on continuous measurement of CO_2 at various stages of the CCS project.[60] It is assumed for simplicity in this methodology that CO_2 is not transported in containers (e.g., by truck, rail or ship) and that all CO_2 is transported by pipeline.[61]

These flow measurements may be performed using either mass flow meters or volumetric flow meters. All of the calculations in the body of this document rely on volumetric measurements, but alternatively a mass-based measurement may be used. Both mass and volume based measurement approaches are described in the following examples, below. Note that in these illustrative examples, measurements are assumed to be quarterly and other measurement frequencies may be required for CCS projects.

For a mass flow meter, the total mass of CO_2 must be calculated in metric tons by multiplying the metered mass flow by the concentration in the flow, according to the following equations.

EQUATION D.1

$$CO_{2_{x,y}} = \sum_{p=1}^{4} (Q_{x,p}) * C_{CO_{2,x,p}}$$

Where:

$CO_{2_{x,y}}$	=	Net annual mass of CO_2 measured by flow meter x (metric tons) in year y
$Q_{x,p}$	=	Quarterly mass flow through meter x in quarter p (metric tons)
$C_{CO_{2,x,p}}$	=	CO_2 concentration measurement in flow for flow meter x in quarter p (wt. percent CO_2, expressed as a decimal fraction)
p	=	quarter of the year
x	=	flow meter

For a volumetric flow meter, the total mass of CO_2 is calculated in metric tons by multiplying the metered volumetric flow at standard conditions by the CO_2 concentration in the flow, according to the formula below.

To apply the equation below, all measured volumes are converted to the following standard industry temperature and pressure conditions for use in the equation below: standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

EQUATION D.2

$$CO_{2_{x,y}} = \sum_{p=1}^{4} (Q_{x,p}) * D * C_{CO_{2,x,p}}$$

Where:

$CO_{2_{x,y}}$	=	Net annual mass of CO_2 measured by flow meter x (metric tons) in year y
$Q_{x,p}$	=	Quarterly volumetric flow through meter x in quarter p at standard conditions (standard cubic meters)
D	=	Density of CO_2 at standard conditions (metric tons per standard cubic meter)
$C_{CO_{2,x,p}}$	=	CO_2 concentration measurement in flow for flow meter x in quarter p (vol. percent CO_2, expressed as a decimal fraction)
p	=	quarter of the year
x	=	flow meter

When CO_2 is measured using more than one meter within the same component of the CCS project (e.g., multiple CO_2 injection wells), it may be necessary to sum the meter readings to calculate an aggregate mass of CO_2, as shown in the following equation.

EQUATION D.3

$$CO_{2_y} = \sum_{x=1}^{X} CO_{2_{x,y}}$$

Where:

CO_{2_y}	=	Total mass of CO_2 measured by all flow meters in year y (metric tons)
$CO_{2_{x,y}}$	=	Total mass of CO_2 measured by flow meter x, as calculated in Equation D.1 or Equation D.2 in year y (metric tons)
x	=	flow meter

ADDITIONAL METHOD FOR CALCULATING EMISSIONS FROM ELECTRICITY USE

The following equation can be used to quantify GHG emissions from the use of grid electricity at any component of a CCS project as a contingency if a distinct electricity meter reading is unavailable (e.g., other loads that are unrelated to the CCS project are tied into the same meter).

EQUATION D.4

$$PE_{Elec,\,y} = \sum (\text{Electrical Rating}_i \times \text{Hours}_i \times \text{Load}_i) \times EF_{Electricity}$$

Where,

$PE_{S\text{-}P\text{-}Elec,\,y}$	=	Project emissions from electricity used to operate equipment at the CO_2 storage site in the producing formation in year y (tCO_2e/yr).
Electrical Rating $_i$	=	Electrical rating in MW for each piece of equipment used to operate equipment associated with the relevant component (e.g., capture, transport or storage) of the CCS project (MW).
Hours $_i$	=	Operating hours for each piece of equipment (hours). Estimated or assumed to be 8760 hours for conservativeness.
Load $_i$	=	% Loading of each piece of equipment (unitless). Estimated or assumed to be 100%.
$EF_{Electricity}$	=	Emission factor for electricity generation in the relevant region (tCO_2e/MWh).

ADDITIONAL METHOD FOR CALCULATING STATIONARY COMBUSTION EMISSIONS FROM THE PRIMARY PROCESS BASED ON FUEL USE

The following equation can be used to quantify GHG emissions from stationary combustion from the primary process at the capture site. It can be used for projects where directly measuring the volume (or mass) of CO_2 produced at the primary process is not possible.

EQUATION D.5

$$CO_2\ \text{Produced}_{PP,\,y} = \sum(\text{Fuel}_i \times \text{Mass Frac}_{Carbon,\,i} \times 44/12)$$

Where,

CO_2 Produced $_{PP,\,y}$	=	Gross amount of CO_2 produced from the primary process in each year (tCO_2/yr).
Fuel $_i$	=	Total volume or mass of fuel, by fuel type i, input into the primary process in year each (e.g., m^3 or kg).
Mass Frac $_{Carbon,\,i}$	=	Average mass fraction of carbon in fuel type i, (fraction expressed as a decimal).
44/12	=	Conversion factor to convert from mass of carbon to mass of carbon dioxide using molecular weights (unitless).

ADDITIONAL METHOD FOR CALCULATING STATIONARY COMBUSTION EMISSIONS FROM FLARING

The following equation can be used to quantify GHG emissions from stationary combustion at the storage site in the producing formation in situations where a flare is used to combust gases produced from the formation (e.g., gases that may contain CO_2 that originates from the capture site).

EQUATION D.6

$$PE_{Flaring,\,y} = \sum(\text{Gas Flared}_i * \sum(C_i * y_i) * 44.01/23.64) + \sum(\text{Flare Fuel}_i * EF\ CO_{2\ \text{Flare Fuel } i}) +$$
$$\sum[\text{ Gas Flared}_i * (1\text{-}DE) * \%CH_4 * \rho\ CH_4) * GWP_{CH4} + \sum(\text{ Flare Fuel}_i * \%CH_4 * \rho\ CH_4 * (1 - DE))]*$$
$$GWP_{CH4} + \sum(\text{Vol.}_{\text{Gas Flared}} * EF\ N_2O_{\text{Gas Flared } i}) + (\text{Flare Fuel}_i * EF\ N_2O_{\text{Flare Fuel } i})] * GWP_{N2O}$$

Where,

$PE_{Flaring,\ y}$	=	Project emissions from flaring of gases at hydrocarbon production facilities in year y (tCO_2e/yr). Only applicable to facilities that flare gases that may contain CO_2 originating from the producing formation.
Gas Flared $_i$	=	Volume of gas flared at hydrocarbon production facilities at the storage site in the producing formation in year y (m^3/year).
Flare Fuel $_i$	=	Volume of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation in year y (m^3/year).
C_i	=	Number of carbon atoms would be assessed based on the chemical formula of each gas (e.g., 1 for CH_4, 1 for CO_2, 2 for C_2H_6)
y_i	=	Direct measurement of the mole fractions of each carbon-containing gas in the gas mixture.
44.01	=	Reference value for Molecular Weight of CO_2 (grams per mole).
23.64	=	Volume occupied by 1 mole of an ideal gas at standard conditions of 15°C and 1 atmosphere.
DE	=	Destruction efficiency of the flare (unitless).
$\%CH_4$	=	Concentration of CH_4 in the gas stream that is being flared in year y (volume percent CO_2 or CH_4, expressed as a decimal fraction).
$\rho\ CH_4$	=	Density of CO_2 at standard conditions (metric ton/ m^3).
$EF\ N_2O_{\text{Gas Flared } i}$	=	N_2O emission factor for flaring of gas stream originating from the producing formation (e.g., tN_2O/m^3).
$EF\ CO_{2\ \text{Flare Fuel } i}$	=	CO_2 emission factor for combustion of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation (e.g., tCO_2/m^3).
$EF\ N_2O_{\text{Flare Fuel } i}$	=	N2O emission factor for combustion of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation (e.g., tN_2O/m^3).
GWP_{CH4}	=	Global Warming Potential of methane = 21.
GWP_{N2O}	=	Global Warming Potential of N_2O = 310.

ADDITIONAL GUIDANCE ON SELECTING EMISSION FACTORS TO QUANTIFY FUGITIVE EMISSIONS

The following table provides a summary of potential fugitive and venting emission sources and relevant US EPA emission factors that may be applicable to CO_2 injection and storage facilities as well as to hydrocarbon production facilities at the storage site in the producing formation.

TABLE D.1: Surface Components as Potential Emissions Sources at Injection Facilities[62]

EMISSIONS SOURCE	ENGINEERING ESTIMATES	DIRECT MEASUREMENT	EQUIPMENT COUNT AND POPULATION FACTOR	REFERENCE IN EPA GHGRP SUBPART W
Natural gas pneumatic high bleed device venting			X	EQ. W-1
Natural gas pneumatic high low device venting			X	EQ. W-1
Natural gas pneumatic intermittent bleed device venting			X	EQ. W-1
Natural gas driven pneumatic pump venting			X	EQ. W-1
Reciprocating compressor rod and packing venting			X	Eq. W-26 and W-27
EOR Injection Pump			X	
EOR injection pump blowdown	X			Eq. W-37
Centrifugal compressor wet seal oil degassing venting			X	Eq. W-22 to W-25
Other equipment leaks (valve, connector, open-ended line, pressure relief valve)			X	Eq. W-31

ENDNOTES

1 Since accounting for indirect emissions inherently double-counts direct emissions, program authorities will decide if it is appropriate to include indirect emissions in its program.

2 EPA's Greenhouse Gas Reporting Program requires the annual reporting of GHG data and other relevant information from facilities that emit 25,000 metric tons or more per year of GHGs. The reporting rules also apply to facilities that supply certain products that would result in GHG emissions if released, combusted or oxidized and facilities that inject CO2 underground for geologic sequestration or any purpose other than geologic sequestration. The rule has 47 subparts and can be found at www.epa.gov/climatechange/emissions/ghgrulemaking.html

3 Program authorities may need to supplement EPA's Subpart RR MRV procedures with requirements of their own to fulfill program-specific needs.

4 ISO 14064-2 is consistent with the voluntary offset programs operated by the Climate Action Reserve (CAR), the America Climate Registry (ACR), and the Verified Carbon Standard (VCR), as well as the compliance program operated by the Province of Alberta and the offset protocols accepted by the California Air Resources Board and the Clean Development Mechanism (CDM).

5 California Health and Safety Code, §38562(d)(1). Other GHG offset programs—e.g., CAR, ACR, VCS, Alberta Offset System—also require that offset projects be consistent with the project accounting criteria. Each program authority develops it own rules for satisfying the criteria.

6 The process to define a baseline is often a part of an "additionality" assessment. The CCS Accounting Framework, however, decouples baselines from additionality and discusses baseline options for the purpose of calculating the difference between the baseline and project emissions.

7 Generally, this document does not define a "deminimis" emissions threshold, which would affect whether project developers calculate emissions from small sources. Program authorities would create rules to determine the minimum level of emissions to account for and report to their respective programs and/or specify the types of emissions sources to exclude from the GHG reduction assessment.

8 This variable is included to maintain functional equivalence between the baseline and project.

9 The CCS Accounting Framework does not include calculation procedures to determine mobile source emissions, as it is generally recognized that a change in mobile emissions would not impact the calculated reductions from the project. The document also does not include procedures to determine one-time emissions productions from project construction.

10 For gasification projects, the total mass of CO_2 produced would be determined based on the mass or volume and carbon content of the syngas produced from the gasifier, measured at a point upstream of the water-gas shift reactor and subsequent hydrogen purification steps. Note that carbon contained in char, slag or ash produced during gasification would not be included in the total amount of produced CO_2.

11 The CO_2 capture unit may only require a portion of the total electricity and/or heat output from the cogeneration unit so it might be necessary to account for the fraction of emissions from the cogeneration unit that are attributable to the CCS project.

12 For CO_2 transported in containers, quantification guidance can be found EPA Subpart RR, 40 CFR § 98.443.

13 This approach follows the methods outlined in EPA Subpart PP-Suppliers of Carbon Dioxide. 40 CFR § 98.423, Equation PP-3b.

14 Composition of gas delivered to storage site is assumed to be same composition as the gas at inlet to the pipeline.

15 If permitted by a program authority, project developers could derive a CO_2 pipeline emission factors based on natural gas transmission factors and then convert from methane to CO_2 (emissions CO_2/kilometer of pipeline). The American Petroleum Institute's Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (2004) is one source for a pipeline emissions factor.

16 This approach is consistent with the EPA's GHGRP, as explained in its "General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU." Greenhouse Gas Reporting Program. November 2010. www.epa.gov/climatechange/emissions/subpart/rr.html.

17 Appendix D provides a summary of potential fugitive emission sources and resources for emission factors that may be applicable to CO2 injection and storage facilities.

18 See, for example, the National Institute of Standards and Technology database of thermodynamic properties using the Span and Wagner Equation of State. http://www.nist.gov/data/PDFfiles/jpcrd516.pdf

19 Appendix D provides a procedure for calculate emissions from combusting hydrocarbons produced at the formation (e.g., in flares).

20 For CO_2 Injection pump blowdowns it may be necessary to use the density of CO_2 at supercritical conditions, which can be obtained from the National Institute of Standards and Technology (NIST) Database of thermodynamic properties using the Span and Wagner Equation of State.

21 For a discussion of detection thresholds, see Benson, S. (2006). *Monitoring Carbon Dioxide Sequestration in Deep Geological Formations for Inventory Verification and Carbon Credits*. Richardson, TX: Society of Petroleum Engineers.

22 Note: fugitive emissions from injection wells could be calculated according to Equation 7.3, as an emission factor is provided in EPA's GHGRP, see Appendix D.

23 Project monitoring—and especially monitoring the geologic storage of CO_2—is referred to in multiple ways, including "monitoring, verification, and accounting," "monitoring, reporting, and verification, "monitoring, measurement, and verification," among others. The CCS Accounting Framework uses term "project monitoring" to refer to the suite of activities to measure, collect, and organize data across the full value chain of a CCS project to assess project performance.

24 Monitoring CO_2 capture facilities, pipelines, and storage sites to maintain compliance with local, state, and federal environmental health and safety requirements is outside the scope of this GHG accounting methodology.

25 The process to address CO_2 leakage from the geologic storage reservoir is presented in Sections 9.2.3 and 9.2.4.

26 40 CFR §98.448(a). A monitoring plan for Subpart RR to EPA's GHGRP would also include well classification information, and data collection timing information, among other things.

27 "Maximum monitoring area" and "active monitoring area" are defined terms in the EPA GHGRP—40 CFR §98.449.

28 See EPA's GHGRP website: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

29 CO_2 pipelines do not have an obligation to report GHG emissions data to EPA; the monitoring procedures to determine GHG emissions from CO_2 transport in this document follow common practice procedures.

30 For a thorough review of additionality and the clean development mechanism please see Pew's white paper on the Clean Development Mechanism, a Review of the First International Offset Mechanism, March, 2011.

31 http://www.climateactionreserve.org/how/protocols/.

32 See, for example, provisions for sector-level crediting under the California Air Resources Board's Cap and Trade Regulation Order (§ 95991-95997) available at: http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

33 The baseline candidate least affected by the barriers to implementation usually represents the baseline scenario. It is possible that the proposed project could be the option least affected by the barriers—making it the same as the baseline. However, given the nature of CCS projects and the limited number of U.S. programs to control or price CO_2 emissions, this would likely be exceptional.

34 http://cdm.unfccc.int/Reference/tools/index.html.

35 A programmatic baseline could also be referred to as "performance standard" or "multi-project." The distinction between these similar terms mainly concerns "additionality" issues.

36 Additional information on the Regional Greenhouse Gas Initiative is available at http://www.rggi.org/home.

37 For a review of state-level activities, see CO_2 Capture Project, 2010, Section 5. http://www.co2captureproject.org/.

38 IOGCC, 2007.

39 Benson, 2006.

40 IPCC, 2005.

41 Benson, 2006.

42 Texas Tax Code: SECTION 9, Subchapter B, Sec.202.0545 (d)(1).

43 State of Washington 2008. WAC §§ 173-218-115(4)(a)(i)(A). Definitions.

44 See, for example, California's Carbon Capture and Storage Review Panel Recommendations, 2010; CA CCS Review Panel Recommendations, 2010.

45 40 CFR §144.12.

46 http://water.epa.gov/type/groundwater/uic/.

47 For information about program implementation in specific States, Tribes, or Territories, see http://www.epa.gov/ogwdw/uic/pdfs/Delegation%20status.pdf.

48 http://water.epa.gov/type/groundwater/uic/class6/gsregulations.cfm

49 40 CFR Part 144 and Subpart-C of Part 146.

50 40 CFR, §144.19.

51 40 CFR §144.12.

52 Conceivably, CO_2 could migrate out of a CO_2 storage complex without contaminating an underground source of drinking water and leak to the atmosphere through the injection well or a transmissive fault that bypasses the aquifer, for instance.

53 EPA's Greenhouse Gas Reporting Program requires select direct GHG emitters, fossil fuel and industrial gas suppliers, manufacturers of vehicles and engines, and injectors of CO_2 to annually account for and report emissions information on a facility- or product basis. For additional information see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

54 40 CFR §98.440.

55 40 CFR §98.420(a)(2).

56 40 CFR §98.448.

57 Preamble to EPA GHGRP Subpart RR Final Rule, p. 75063. http://www.epa.gov/climatechange/emissions/subpart/rr.html.

58 Note that this diagram does not illustrate vented CO_2 emissions, fugitive CO_2 releases or CO_2 leakage from producing or non-producing formations as the quantification of these emission sources generally does not rely on data from the CO_2 mass balance. For information on the quantification of emissions from these sources refer to the quantification section of the CCS Accounting Framework.

59 Natural gas pipelines often allow for up to 2% CO_2 in natural gas, and if the natural gas originates from the producing formation that CO_2 is being injected into, then the combustion of this natural gas would result in the release of entrained CO_2 that originated from the capture site.

60 This section has been adapted from US EPA Subpart RR. December 1, 2010.

61 For CO_2 transported in containers refer to US EPA Subpart RR. December 1, 2010.

62 US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010.

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The Center for Climate and Energy Solutions (C2ES) is an independent non-profit, non-partisan organization promoting strong policy and action to address the twin challenges of energy and climate change. Launched in 2011, C2ES is the successor to the Pew Center on Global Climate Change.

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