Mitigation Measure M-GCC-7
Attachment "A"

Part 2 of 3: American Carbon Registry

PREFACE

During the Village 13 Project's implementation phase and prior to the County's issuance of Project-related grading and building permits, the County shall reference and use Mitigation Measure M-GCC-7 Attachment "A" to determine whether the Project is proposing to use eligible carbon offset project types to meet its CEQA mitigation obligations under mitigation measures M-GCC-7 and M-GCC-8. This Preface describes the contents of Attachment "A."

Mitigation Measure M-GCC-7 Attachment "A" contains copies of the manuals used by the Climate Action Reserve, American Carbon Registry and Verra to administer their carbon offset programs. Each manual contains the foundational principles and standards deployed by the registries to ensure that their carbon offset programs achieve high standards of environmental integrity. As such, the manuals contain generally applicable GHG reduction accounting guidelines; rules and procedures for carbon offset project registration, implementation, and verification; and, standards for the development of protocols and methodologies. The registries' program manuals are updated from time to time; reference should be made to the current iteration of each manual, as needed.

Mitigation Measure M-GCC-7 Attachment "A" also contains all of the carbon offset protocols and methodologies of these three registries that the County has determined to be eligible for use when reducing GHG emissions pursuant to mitigation measures M-GCC-7 and M-GCC-8 of the Village 13 Project's EIR. While the following bulleted summary is not an exhaustive listing of the types of information contained in protocols and methodologies, each of the Attachment "A" protocols and methodologies routinely provide the following type of information:

- A description of the specific carbon offset project type, and associated definitional parameters;
- Eligibility rules pertaining to project location, start date, the crediting period, the additionality tests, and regulatory compliance;
- A description of the GHG assessment boundary and rules for quantifying both baseline and project emissions; and,
- Project monitoring and reporting requirements, including related verification standards.

The County of San Diego has reviewed and determined that the protocols and methodologies included in Attachment "A" establish and require carbon offset projects to comply with standards designed to achieve additional, real, permanent, quantifiable, verifiable and enforceable reductions. In making this determination, the County reviewed the registries' program manuals, the registries' websites (which provide additional background information on each protocol and methodology, including comments from interested members of the public and experts in the field), and the registries' protocols and methodologies included herein. As such, when implementing mitigation measures M-GCC-7 and M-GCC-8, the Village 13 Project shall procure offsets only from the carbon offset project types authorized by the Attachment "A" protocols and methodologies.

The Attachment "A" protocols and methodologies are periodically updated by the registries, pursuant to their established processes, in response to public comments, on-the-ground experience, and technological, scientific and regulatory developments. Updates ensure no reduction in efficacy

and environmental integrity, in accordance with the registries' program manuals. Related iterations of the protocols and methodologies for the carbon offset project types listed herein may be used. However, protocols and methodologies for carbon offset project types that are not listed herein cannot be utilized by the Village 13 Project, absent additional evaluation and action by the County of San Diego.

MITIGATION MEASURE M-GCC-7
ATTACHMENT "A"

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PART 2 OF 3: AMERICAN CARBON REGISTRY

The American Carbon Registry Standard: Requirements and Specifications for the Quantification, Monitoring, Reporting, Verification, and Registration of Project-Based GHG Emissions Reductions and Removals, version 6.0 (July 2019)

Truck Stop Electrification

Advanced Refrigeration Systems

Certified Reclaimed HFC Refrigerants

The Destruction of Ozone Depleting Substances and High-GWP Foam

Transition to Advanced Formulation Blowing Agents In Foam Manufacturing and Use

Afforestation and Reforestation of Degraded Land

Avoided Conversion of Grasslands and Shrublands to Crop Production

Compost Additions to Grazed Grasslands

Improved Forest Management (IFM) for Non-Federal U.S. Forestlands

Restoration of California Deltaic and Coastal Wetlands

Restoration of Degraded Deltaic Wetlands of the Mississippi Delta

Restoration of Pocosin Wetlands

Carbon Capture and Storage Projects

Capturing and Destroying Methane from U.S. Coal And Trona Mines

Re-Refining Used Lubricating Oils

Landfill Gas Destruction and Beneficial Use Projects

Recycling of Transformer Oil

MITIGATION MEASURE M-GCC-7
ATTACHMENT "A"

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** As provided in mitigation measures M-GCC-7 and M-GCC-8, the protocols and methodologies, and other related documents contained in this Attachment are periodically updated by the registries, pursuant to their established processes, in response to public comments, on-the-ground experience, and technological, scientific and regulatory developments. Related iterations of the protocols and methodologies for the carbon offset project types listed herein may be used during the mitigation implementation phase. However, protocols and methodologies for carbon offset project types that are not listed herein cannot be utilized, absent additional County evaluation and action.*

THE AMERICAN CARBON REGISTRY STANDARD

REQUIREMENTS AND SPECIFICATIONS FOR THE QUANTIFICATION, MONITORING, REPORTING, VERIFICATION, AND REGISTRATION OF PROJECT-BASED GHG EMISSIONS REDUCTIONS AND REMOVALS

VERSION 6.0

July 2019

THE AMERICAN CARBON REGISTRY STANDARD

REQUIREMENTS AND SPECIFICATIONS FOR THE QUANTIFICATION, MONITORING, REPORTING, VERIFICATION, AND REGISTRATION OF PROJECT-BASED GHG EMISSIONS REDUCTIONS AND REMOVALS

VERSION 6.0

July 2019

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance, and retirement reporting through its online registry system.

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ACRONYMS

ACR	American Carbon Registry®
AEZ	agroecological zone
AFOLU	Agriculture, Forestry, and Other Land Use
CCBA	Climate, Community and Biodiversity Alliance
CDM	Clean Development Mechanism
CER	certified emission reduction
CO_2e	carbon dioxide-equivalent
CORSIA	Carbon Offset Reduction Scheme for International Aviation
DNA	Designated National Authority
ERT	Emission Reduction Ton
GIS	Geographic Information System
GHG	greenhouse gas
GWP	global warming potential
HFC	hydrofluorocarbon
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
NDC	nationally determined contributions
ODS	ozone-depleting substance
OPR	Offset Project Registry
PDA	Programmatic Development Approach
QA/QC	quality assurance/quality control
REC	Renewable Energy Credit or Renewable Energy Certificate
RPS	Renewable Portfolio Standard

SOC	soil organic carbon
UNFCCC	United Nations Framework Convention on Climate Change
VVB	Validation/Verification Body

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INTRODUCTION

The American Carbon Registry® (ACR) is a leading carbon offset program with two decades of unparalleled carbon market experience in the development of rigorous, science-based offset standards and methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance, and retirement reporting through ACR's online registry system. ACR is a nonprofit enterprise of Winrock International. Winrock works with people in the United States and around the world to empower the disadvantaged, increase economic opportunity, and sustain natural resources. Key to this mission is building capacity for climate change mitigation and adaptation and leveraging the power of environmental markets. Since the 1990s, Winrock has been a leader in developing science-based greenhouse gas (GHG) measurement and monitoring methods and protocols.

ACR was founded in 1996 as the GHG Registry by the Environmental Resources Trust, and joined Winrock in 2007. As the first private GHG registry in the world, ACR has set the bar for offset quality that is the market standard today and continues to lead carbon market innovation.

In 2012, ACR was approved by the California Air Resources Board to serve as an Offset Project Registry (OPR) and Early Action Offset Program for the California cap-and-trade market. ACR's work as a California OPR is governed by the California cap-and-trade regulation and compliance offset protocols approved by the Air Resources Board.[1] The ACR Standard governs only the registration of projects under ACR-approved methodologies.

ACR GOVERNANCE

The ACR program is built on principles of accountability, transparency, responsiveness, and participatory processes. As an enterprise of Winrock, ACR benefits from the support and guidance of an established, reputable, global nonprofit organization. Winrock's management, executive team, and board of directors provide direct oversight of all ACR operations.

THE ACR STANDARD

The ACR Standard details ACR's requirements and specifications for the quantification, monitoring, and reporting of project-based GHG emissions reductions and removals, verification, project registration, and issuance of offsets. The Standard establishes the quality level that every project must meet in order for ACR to register its GHG emissions reductions and removals as tradable environmental assets.

[1] The California cap-and-trade regulation (Subchapter 10 Climate Change, Article 5, Sections 95801 to 96022, Title 17, California Code of Regulations) and currently approved compliance offset protocols are available at http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

ACR aims to maximize flexibility and usability for Project Proponents while maintaining the environmental integrity and scientific rigor necessary to ensure that projects developed against its standards and methodologies are recognized as being of the highest quality, whether used for voluntary or pre-compliance early action purposes.

Adherence to the ACR Standard and associated methodologies will ensure that project-based offsets represent emissions reductions and removals that are real, measurable, permanent, in excess of regulatory requirements and common practice, additional to business-as-usual, net of leakage, verified by a competent independent third party, and used only once.

APPLICABILITY

Project Proponents wishing to develop a project for registration on ACR shall follow this Standard and must apply an ACR-approved methodology (as defined below).

The ACR Standard v6.0 supersedes the ACR Standard v5.1 (May 2018). Any project listed subsequent to August 1, 2019, must follow all requirements of and be validated against the ACR Standard v6.0. New projects listed prior to August 1, 2019, may be validated according to a previous version of the ACR Standard, as applicable at the time of listing. All Projects shall be verified to the version of the ACR Standard against which they were validated through the end of their Crediting Period.

Project Proponents and other interested parties should refer to www.americancarbonregistry.org for the latest version of the ACR Standard, methodologies, tools, document templates, and other guidance.

CHAPTER GUIDE

Chapter 1 Basics on ACR

Chapter 2 ACR's general accounting and data quality principles for offset projects

Chapter 3 ACR project eligibility requirements

Chapter 4 ACR tests to ensure that offset projects are additional to business-as-usual

Chapter 5 ACR's approach to ensuring permanence of GHG reductions and removals

Chapter 6 Process for Project Proponents to develop and register a project

Chapter 7 Processes for ACR approval of new methodologies and methodology modifications

Chapter 8 ACR requirements for Assessing Environmental and Community Impactss

Chapter 9 ACR requirements for validation and verification of all projects by a competent independent third-party verifier, which are addressed in greater detail in the ACR Validation and Verification Standard for GHG Projects

Chapter 10 ACR linkages to other GHG programs and registries, emission trading systems, and national or sectoral GHG emissions reduction targets

Chapter 11 ACR's appeals and complaints procedure

Appendix A ACR Requirements for Agriculture, Forestry, and Other Land Use (AFOLU)-based carbon projects

Appendix B ACR Buffer Pool Terms and Conditions, which details requirements for AFOLU projects that utilize the Buffer Pool for reversal risk mitigation

Appendix C Normative references on which the ACR Standard is based

Appendix D References on which the ACR Standard is based

The ACR Standard does not detail legal responsibilities of ACR and ACR members with regard to the use of the registry, which are provided for in the legally binding ACR Member Terms of Use Agreement and referenced operative documents such as the ACR Operating Procedures. A project-specific legal contract between ACR and Project Proponents governs use of ACR-approved risk mitigation mechanisms, including the ACR Buffer Pool, to mitigate the risk of reversals in certain types of projects.

CITATION

The appropriate citation for this document is American Carbon Registry (2019). The American Carbon Registry Standard, version 6.0., Winrock International, Little Rock, Arkansas.

CHAPTER 1: ACR BASICS

1.A DESCRIPTION OF THE ACR

The American Carbon Registry®, a nonprofit enterprise of Winrock International, is a leading carbon offset program that operates in both the voluntary and the regulated carbon markets. Founded in 1996 as the first private voluntary GHG registry in the world, ACR has two decades of unparalleled carbon market experience in the development of rigorous, science-based offset standards and methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance, and retirement reporting.

ACR operates a transparent online registry system for members to register projects and record the issuance, transfer, and retirement of serialized, project-based, and independently verified offsets. ACR's registry system records transactions directly negotiated between buyers and sellers; it is not an exchange. Offset transactions take place outside of ACR, over-the-counter or on exchanges, and are tracked on ACR through the unique serial numbers assigned to every offset.

1.B OBJECTIVES

ACR's objectives are to:

- Encourage action to manage GHG emissions;
- Provide guidance, transparent infrastructure, and science-based standards to foster high-quality reductions in GHG emissions;
- Support best practices in project-level GHG accounting;
- Commercialize innovative new methodologies;
- Encourage broad adoption of practices that mitigate climate change with significant community, economic, and environmental benefits;
- Enhance public confidence in market-based action for GHG reduction; and
- Support convergence of international and U.S. carbon markets.

1.C GEOGRAPHIC SCOPE

ACR accepts projects from worldwide locations, provided they conform to an ACR-approved methodology. Certain sectors and methodologies prescribe a narrower geographic scope (e.g., United States only).

1.D SCOPE: GREENHOUSE GASES AND PARTICULATE MATTER

ACR registers emission reductions and/or removal enhancements of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons, sulfur hexafluoride (SF_6), and black carbon. ACR's scope also includes destruction of Ozone-Depleting Substances (ODS) listed in Annexes A, B, C, and E of the Montreal Protocol.[2]

1.E SCOPE: PROJECT TYPES

ACR accepts all projects validated and verified against an ACR-approved methodology, provided they comply with the current version of the ACR Standard. ACR-approved methodologies include:

- Methodologies developed by ACR and approved through the public consultation and scientific peer review process;
- Methodologies approved by the Clean Development Mechanism (CDM) Executive Board, provided that, at the request of the Project Proponent, it has been reviewed and approved by ACR per the requirements found in Chapter 7;
- Modifications of existing ACR methodologies, provided such modifications have been approved by ACR per requirements found in Chapter 7; and
- New methodologies developed by external authors and approved by ACR through ACR's methodology development process described in Chapter 7.

1.E.1 Renewable Energy and Energy Efficiency Projects

ACR will register GHG reductions from renewable energy and energy efficiency projects if all of the following criteria are met:

- The project displaces direct emissions by reducing the consumption of fossil fuels at a facility that the Project Proponent owns or controls, or for which the facility owner has assigned the Project Proponent clear and uncontested offsets title. Examples are biomass co-firing with coal, biogas used to displace natural gas, and energy efficiency projects that reduce natural gas use;
- The project meets additionality and other requirements of the ACR Standard;
- The GHG reductions have not been used to meet a regulatory compliance obligation under a binding limit;
- Under jurisdictional (i.e. federal, lstate, provincial, etc.) regulations, the project does not take place at a regulated source; and

[2] See http://ozone.unep.org/Publications/MP_Handbook.

- The project has not been counted toward a mandatory renewable energy obligation (such as a renewable portfolio standard) obligation or claimed any other voluntary renewable energy incentive (such as renewable energy credits).

1.E.2 Scope Exclusions

The following scope exclusions apply under the ACR program:

- Projects that do not meet all ACR eligibility criteria, including projects that convert and/or clear native ecosystems to generate carbon offsets;
- Renewable energy and energy efficiency projects unless meeting all criteria above;
- International project-level REDD (Reducing Emissions from Deforestation and Degradation) from REDD+ countries. The growing international implementation of land-based sectoral GHG accounting and crediting and/or results-based finance (REDD+) greatly increases the risk of double claiming project-based offset credits within a sectoral crediting scheme; and
- Projects quantifying energy or life-cycle GHG accounting-based indirect emissions reductions and removals.

1.F LANGUAGE

English is the operating language of ACR. All GHG Project Plans, methodologies, tools, verification statements, and other documents required by ACR shall be in English.

1.G UNIT OF MEASURE

Project Proponents shall calculate, quantify, and report all GHG reductions and removal enhancements in metric tons, converting each metric ton to its CO_2 equivalent (CO_2e) using calculations based on the 100-year Global Warming Potential factors listed in the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4), Working Group 1, Chapter 2, Table 2.14.[3]

1.H UNIT OF EXCHANGE

The ACR unit of exchange is a verified emissions reduction, serialized and registered as an Emission Reduction Ton (ERT), denominated in metric tons of CO_2e. ERTs, also referred to as offsets, carbon offsets, and carbon offset credits, include emission reductions and removal enhancements (i.e., enhanced sequestration).

[3] See http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

1.I NO EX-ANTE CREDITING

A project-based offset is the result of a defined and eligible project action that yields quantifiable and verifiable GHG emissions reductions/removals. ACR will not issue ERTs for GHG emissions reductions or removals when an emission mitigation activity has not occurred or is not yet verified. ACR will not credit a projected stream of offsets on an ex-ante basis.

1.J ADOPTION OF AND REVISIONS TO ACR STANDARDS

All ACR Standards will be posted for public comment for at least 60 days prior to adoption. ACR will prepare responses to all submitted comments and post the comments and responses along with the new version of the standard.

ACR will review and revise the ACR Standard, as necessary, at a minimum of every 3 years.

Such updates occur when significant changes to GHG accounting best practices or the legislative and/or regulatory context justify an update; when new provisions or requirements originating in methodologies make ACR aware of higher-level requirements or clarifications that should be made at the ACR Standard; upon an update to ACR's internal policy and/or process requirements; or for other reasons.

On a project level and in certain circumstances, ACR may require all projects, including those validated under a previous version of the ACR Standard, to immediately implement a policy or process revision (e.g., updated administrative reporting procedures) detailed in a subsequent version of the ACR Standard.

1.K CONFLICT OF INTEREST POLICY

As a nonprofit organization that values its reputation for integrity, Winrock requires that all management and staff adhere to its Code of Professional Conduct, which includes a strict and comprehensive policy against engaging in activities that present a conflict of interest. Accordingly, each Winrock director, officer, and staff member, including ACR staff, are required to regularly affirm that they are in compliance with this policy, that they avoid all conflicts of interest and take reasonable action to avoid circumstances that create the appearance of a conflict of interest. Winrock and ACR staff are required to notify management immediately if any conflict of interest situations arise or come to their attention so the conflict can be appropriately mitigated.

In addition to its internal conflict of interest policy, ACR requires that its third-party registry service provider maintain and adhere to a strict conflict of interest policy and that all ACR-approved Validation and Verification Bodies (VVBs) execute an Attestation of Validation/Verification Body, which defines the VVB role and responsibilities and ensures technical capabilities of all staff and

no conflicts of interest. ACR-approved VVBs must also execute a project-specific conflict of interest form for each project validated and/or reporting period verified, which ACR reviews and approves.

CHAPTER 2: ACCOUNTING AND DATA QUALITY PRINCIPLES

The accounting and data quality principles summarized here are designed to ensure that the assumptions, values, and procedures used by Project Proponents and VVBs result in a fair and true accounting of GHG emission reductions and removals.

2.A GUIDING PRINCIPLES FOR GHG ACCOUNTING

ACR affirms a set of guiding principles, based on the International Organization for Standardization (ISO) 14064 Part 2 (2006) specifications from which all other ACR principles and eligibility criteria follow, as summarized in Table 1.

Table 1: Core GHG Accounting Principles

RELEVANCE	Select the GHG sources, GHG sinks, GHG reservoirs, data, and methodologies appropriate to the needs of the intended user.
COMPLETENESS	Include all relevant GHG emissions and removals. Include all relevant information to support criteria and procedures.
CONSISTENCY	Enable meaningful comparisons in GHG-related information. Use consistent methodologies for meaningful comparisons of emissions over time. Transparently document any changes to the data, boundary, methods, or any other relevant factors.
ACCURACY	Reduce bias and uncertainties as far as is practical.
TRANSPARENCY	Disclose sufficient and appropriate GHG-related information to allow intended users to make decisions with reasonable confidence. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.
CONSERVATIVENESS	Use conservative assumptions, values, and procedures to ensure that GHG emission reductions or removal enhancements are not overestimated.

2.B METHODOLOGICAL SPECIFICATIONS FOR ADHERENCE TO GUIDING PRINCIPLES

2.B.1 Boundary Selection

GHG project boundaries include a project's physical boundary or implementation area, the GHG sources, sinks and reservoirs (or pools) considered, and the project duration.

Approved methodologies establish criteria for the selection of relevant GHG sources, sinks, and reservoirs for regular monitoring or estimation. The Project Proponent shall justify in the GHG Project Plan the exclusion from regular monitoring of any relevant GHG source, sink, or reservoir.

In accordance with ISO 14064-2:2006, approved methodologies establish criteria and procedures for quantifying GHG emissions and/or removals for selected GHG sources, sinks, and/or reservoirs. The Project Proponent shall quantify GHG emissions and/or removals separately for each relevant GHG for each GHG source, sink, and/or reservoir identified in the methodology as being relevant for the project and for the baseline scenario.

The Project Proponent shall provide a detailed description of the geographic boundary of Project Activities. A Project Activity may contain more than one facility or discrete area of land, but each facility or land area must have a unique geographical identification, and each land area must meet the sector-specific land eligibility requirements, if applicable. For AFOLU projects, the Project Proponent shall provide maps, Geographic Information System (GIS) shapefiles, and other relevant information to delineate the project boundary.

Sector-specific requirements found in Appendix A specify the required Minimum Project Term for particular project types.

2.B.2 Relevance and Completeness

Consistent with ISO 14064 Part 2, Project Proponents shall consider all relevant information that may affect the accounting and quantification of GHG reductions and removals, including estimating and accounting for any decreases in carbon pools and/or increases in GHG emission sources.

2.B.3 Uncertainty, Accuracy, and Precision

The Project Proponent shall reduce, as far as is practical, uncertainties related to the quantification of GHG emission reductions or removal enhancements.

For methodologies based on statistical sampling (e.g., methodologies in the forestry or working land use sectors), ACR requires that the sampling error associated with the mean of the estimated emission reduction/removal not exceed ±10% of the mean at the 90% confidence interval to report the mean of the estimated emission reduction/removal. If the Project Proponent cannot meet this target, then the reportable amount shall be the mean minus the lower bound of the 90% confidence interval, applied to the final calculation of emission reductions/removal enhancements. If the sampling error is equal to or greater than 20%, the confidence deduction for the monitoring period must be 100%. Project-specific methodologies provide guidance how to calculate this uncertainty deduction. Methodologies submitted for ACR approval shall include methods for estimating uncertainty relevant to the project and baseline scenario.

Project Proponent are responsible for deciding if potential additional revenues from reporting the mean without an uncertainty deduction justify the additional costs of more intensive sampling to achieve precision of ±10% of the mean at 90% confidence, if sampling is required.

The use of biogeochemical or process models must also include an estimate of structural uncertainty related to the inadequacy of the model, model bias, and model discrepancy. This should be quantified using the best available science, and can include Monte Carlo analyses, uncertainty estimates from peer reviewed literature, and/or consulting model experts who have either developed or worked directly with the model in an academic setting.

2.B.4 Conservativeness

The methodology shall define assumptions and specify quantification methods and monitoring requirements to ensure that GHG emission reductions and removals are not overestimated, particularly in cases where estimation methods, not direct measurement, are used to populate parameters.

The following rules shall be applied when reporting emissions data to ACR for offset issuance:

- Claimed emissions reductions shall be rounded down to the nearest whole number; and
- Calculated Buffer Pool contributions shall be rounded up to the nearest whole number.

2.B.5 Emissions Factors

Where needed to estimate GHG emission reductions or removal enhancements in the project or baseline scenario, the methodology shall specify GHG emissions or removal factors that:

- Derive from a scientific peer-reviewed origin;
- Are appropriate for the GHG source or sink concerned; and
- Take account of the quantification uncertainty.

2.B.6 Managing Data Quality

The Project Proponent shall establish and apply quality assurance and quality control (QA/QC) procedures to manage data and information, including the assessment of uncertainty in the project and baseline scenarios. QA/QC procedures shall be outlined in the GHG Project Plan.

2.B.7 Participation in Other Asset Programs

In general, ACR allows carbon offset projects with multiple environmental and/or social attributes to participate in and benefit from programs that quantify achieved benefits beyond those of GHGs. However, participation in such programs is not always consistent with the ACR Standard and principles of carbon offsetting. Proposals for simultaneous reporting of non-carbon attributes will be subject to evaluation upon the ACR project listing review or, for carbon offset projects that have completed this step, upon submission of the proposal. The following requirements must be met for consideration:[4]

- Any project that seeks to register non-carbon environmental attributes alongside offsets must disclose to ACR the intent and details of the program prior to validation, if known;
- The attributes quantified for the non-carbon benefits must be distinct from the GHG benefits such that they have separately defined accounting units (e.g., pounds of nutrients in the case of water quality credits versus metric tons of CO_2e);
- The attributes quantified for the non-carbon benefits must represent a well-defined and distinct ecosystem service that can be "stacked" with offsets, such that they could be financially incentivized separately from the carbon benefit[5]
- The project action must not be required by regulation to achieve the quantified non-carbon benefit; and
- The project action must not compensate for an activity outside the project's geographic boundary that results in release of GHGs or loss of a carbon sink (e.g., wetlands mitigation banking).

[4] This section is not relevant to RECs, which are discussed in Chapter 1, Section E.

[5] Any project using an ACR-approved GHG quantification methodology for issuance of offsets may choose to quantify alternate environmental and/or social benefits. However, these benefits may not always be creditable in a non-carbon environmental market at the same time as the GHG emissions reductions and removals benefits represented by offsets.

CHAPTER 3: PROJECT ELIGIBILITY REQUIREMENTS

Table 2 details ACR eligibility criteria for all projects, defines each criterion, and articulates ACR requirements. Eligibility requirements for specific project types are summarized in the relevant ACR sector standard and/or methodology. Project Proponents shall address, in their GHG Project Plan, each of the criteria below.

Table 2: Eligibility Requirements for Offset Projects

CRITERION	DEFINITION	ACR REQUIREMENT
Start Date[6,7]	ACR defines the Start Date for all projects other than AFOLU as the date on which the project began to reduce GHG emissions against its baseline. ACR defines the eligible Start Date(s) for AFOLU project types in Annex A, "ACR Requirements for AFOLU-Based Carbon Projects."	Non-AFOLU Projects must be validated within 2 years of the project Start Date. AFOLU Projects must be validated within 3 years of the project Start Date. One exception applies to these timeframes: Projects using a newly approved methodology[8] or a newly approved modification that expands the eligibility of a previously published methodology[9] may submit it for listing with ACR within 10 years of the project Start Date. However, the date of listing submittal must be within 6 months of the methodology publication date, and the project must then be validated within 2 years of the listing. The Start Date and the start of the Minimum Project Term shall be the same. The Start Date and the start of the first Crediting Period

[6] The Start Date requirements do not apply to existing ACR projects that renew a Crediting Period. In these instances, the initial project Start Date, as previously validated, shall apply and shall be accepted in the Crediting Period renewal validation process on a de facto basis.

[7] Projects transferring to ACR from another GHG program and that have reached the end of a Crediting Period may apply for an initial Crediting Period at ACR per ACR Standard requirements. The project must have been successfully validated and/or verified at the previous GHG program, and must have a validated/verified Start Date of January 1, 2000, or after.

[8] A methodology is considered "newly approved" if ACR has published it no more than 6 months prior to the project's listing or registration with ACR. See Chapter 6 for guidance on ACR listing and registration requirements.

[9] The project must demonstrate that it was not eligible under the previously published version of the relevant methodology, without the newly approved modification.

CRITERION	DEFINITION	ACR REQUIREMENT
		are generally the same, unless otherwise allowable in the relevant methodology.
Minimum Project Term	The minimum length of time for which a Project Proponent commits to project continuance, monitoring, and verification.	The Minimum Project Term for specific project types is defined in the relevant ACR sector requirements and/or methodology. Project types with no risk of reversal after crediting have no required Minimum Project Term. Project Proponents of AFOLU projects with a risk of reversal shall commit to a Minimum Project Term of 40 years. The minimum term begins on the Start Date, not the first or last year of crediting. The Minimum Project Term is a requirement of the Project Proponent, not necessarily of the landowner (unless the landowner is the Project Proponent). ACR enters into legal agreements only with the Project Proponent. Agreements between Project Proponent and landowner may have a shorter term and/or a "buy-out" option, provided the Project Proponent commits to replace issued ERTs in the event a landowner opts to discontinue Project Activities. See Chapter 4 and Chapter 6. Project Proponents and landowners may continue AFOLU carbon activities beyond the Minimum Project Term, but ACR does not require monitoring or verification unless the Crediting Period is renewed. At the end of the Minimum Project Term, if the Project Proponent does not renew for another Crediting Period and continue monitoring and verification, ACR conservatively assumes that its activities have ceased and retains and may retire any remaining buffer contributions (if applicable).
Crediting Period	Crediting Period is the finite length of time for which a GHG Project Plan is valid, and during	The Crediting Period for non-AFOLU projects shall be 10 years. AFOLU projects may have different Crediting Periods, as specified in the relevant ACR sector requirements or methodology.

CRITERION	DEFINITION	ACR REQUIREMENT
	which a project can generate offsets against its baseline scenario. Crediting Periods are limited in order to require Project Proponents to reconfirm, at intervals appropriate to the project type, that the baseline scenario remains realistic and credible, the Project Activity remains additional, and GHG accounting best practice is being used. This is important because once a project has demonstrated its additionality, it is not required to do so again until applying to renew the Crediting Period.	A Project Proponent may apply to renew the Crediting Period by complying with all then-current ACR requirements, re-evaluating the baseline scenario, reconfirming additionality, and using emission factors, tools, and methodologies in effect at the time of renewal. Except where specified in a methodology, ACR does not limit the number of renewals. Projects that are deemed to meet all ACR additionality criteria are considered additional for the duration of their Crediting Period. If regulations or common practice change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal but does not affect its additionality during the current Crediting Period, unless otherwise specified in the project-specific methodology.
Real	A real offset is the result of a project action that yields quantifiable and verifiable GHG emissions reductions and/or removals.	GHG reductions and/or removals shall result from an emission mitigation activity that has been conducted in accordance with an approved ACR Methodology and is verifiable. ACR will not credit a projected stream of offsets on an ex-ante basis.
Emission or Removal Origin	An emission or removal is direct if it originates from sources or sinks over which the Project Proponent has control. An emission or removal is indirect if it originates at sources or sinks over which the Project Proponent does not have control.	For projects reducing or removing direct emissions, the following requirement applies: The Project Proponent shall own, have control over, or document effective control over the GHG sources/sinks from which the emissions reductions or removals originate. If the Project Proponent does not own or control the GHG sources or sinks, it shall document that effective control exists over the GHG sources and/or sinks from which the reductions/removals originate.

CRITERION	DEFINITION	ACR REQUIREMENT
		For projects reducing or removing non-energy indirect emissions,[10] the following requirement applies: The Project Proponent shall document that no other entity may claim GHG emission reductions or removals from the Project Activity (i.e., that no other entity may make an ownership claim to the emission reductions or removals for which credits are sought).
Offset Title	Offset title is a legal term representing rights and interests in an offset, a future stream of offsets, or a project delivering offsets.	The Project Proponent shall provide documentation and attestation of undisputed title to all offsets prior to registration. Title to offsets shall be clear, unique, and uncontested. ACR will issue offsets into the account of a Project Proponent only if there is clear, unencumbered, and uncontested offset title.
Additional	GHG emission reductions and removal enhancements are additional if they exceed those that would have occurred in the absence of the Project Activity and under a business-as-usual scenario.	Every project shall use either an ACR-approved performance standard and pass a regulatory surplus test, or pass a three-pronged test of additionality in which the project must: 1. Exceed regulatory/legal requirements; 2. Go beyond common practice; and 3. Overcome at least one of three implementation barriers: institutional, financial, or technical.
Regulatory Compliance	Adherence to all laws, regulations, and other legally binding mandates directly related to Project Activities.	Projects must maintain material regulatory compliance. To do this, a regulatory body/bodies must deem that a project is not out of compliance at any point during a reporting period. Projects deemed to be out of compliance with regulatory requirements are not eligible to earn ERTs during the period of non-compliance. Regulatory compliance violations related to administrative processes

[10] ACR will not consider projects or methodologies for indirect emissions reductions/removals based on life-cycle GHG accounting methods.

CRITERION	DEFINITION	ACR REQUIREMENT
		(e.g., missed application or reporting deadlines) or for issues unrelated to integrity of the GHG emissions reductions shall be treated on a case-by-case basis and may not disqualify a project from ERT issuance. Project Proponents are required to provide a regulatory compliance attestation to a verification body at each verification. This attestation must disclose all violations or other instances of non-compliance with laws, regulations, or other legally binding mandates directly related to Project Activities.
Permanent	Permanence refers to the longevity of removal enhancements and the risk of reversal (i.e., the risk that atmospheric benefit will not be permanent). Reversals may be unintentional or intentional.	For projects with a risk of reversal of GHG removal enhancements or avoided conversion projects, Project Proponents shall assess and mitigate risk, and monitor, report, and compensate for reversals. AFOLU Project Proponents shall assess reversal risk using ACR's Tool for Risk Analysis and Buffer Determination, and shall enter into a legally binding Reversal Risk Mitigation Agreement with ACR/Winrock that details the risk mitigation option selected and the requirements for reporting and compensating reversals. Proponents of terrestrial sequestration or avoided conversion projects shall mitigate reversal risk by contributing ERTs to the ACR Buffer Pool or using another ACR-approved insurance or risk mitigation mechanism. Proponents of geologic sequestration projects shall mitigate reversal risk during the project term by contributing ERTs to the ACR Reserve Account and post-project term by filing a Risk Mitigation Covenant, which prohibits any intentional reversal unless there is advance compensation to ACR, or by using another ACR-approved insurance or risk mitigation mechanism.

CRITERION	DEFINITION	ACR REQUIREMENT
		All projects must adhere to ongoing monitoring, reversal reporting, and compensation requirements as detailed in relevant methodologies and legally binding agreements (e.g., the ACR Reversal Risk Mitigation Agreement).
Net of Leakage	Leakage is an increase in GHG emissions or decrease in sequestration outside the project boundaries that occurs because of the project action.	ACR requires Project Proponents to address, account for, and mitigate certain types of leakage, according to the relevant sector requirements and methodology conditions. Project Proponents must deduct leakage that reduces the GHG emissions reduction and/or removal benefit of a project in excess of any applicable threshold specified in the methodology.
Independently Validated	Validation is the systematic, independent, and documented process for the evaluation of a GHG Project Plan against applicable requirements of the ACR Standard and approved methodology.	ACR requires third-party validation of the GHG Project Plan by an accredited, ACR-approved VVB once during each Crediting Period and prior to issuance of ERTs. Validation can be conducted at the same time and by the same VVB as a full verification; however, the deadline for validation is determined by the methodology being implemented and the project Start Date (see above). Governing documents for validation are the ACR Standard, including sector-specific requirements, the relevant methodology, and the ACR Validation and Verification Standard.
Independently Verified	Verification is the systematic, independent, and documented assessment by a qualified and impartial third party of the GHG assertion for a specific reporting period.	Verification must be conducted by an accredited, ACR-approved VVB prior to any issuance of ERTs and at minimum specified intervals. ACR requires verifiers to provide a reasonable, not limited, level of assurance that the GHG assertion is without material discrepancy. ACR's materiality threshold is ±5%.

CRITERION	DEFINITION	ACR REQUIREMENT
Environmental and Community Assessments	Projects have the potential to generate positive and negative community and environmental impacts. Appropriate safeguard procedures can identify, evaluate, and manage potential negative impacts. Positive impacts can contribute to sustainable development objectives.	ACR requires that all projects develop and disclose an impact assessment to ensure compliance with environmental and community safeguards best practices. Environmental and community impacts should be net positive, and projects must "do no harm" in terms of violating local, national, or international laws or regulations. Project Proponents must identify in the GHG Project Plan community and environmental impacts of their project(s). Projects shall also disclose and describe positive contributions as aligned with applicable sustainable development goals. Projects must describe the safeguard measures in place to avoid, mitigate, or compensate for potential negative impacts, and how such measures will be monitored, managed, and enforced. ACR does not require that a particular process or tool be used for the impact assessment as long as basic requirements defined by ACR are addressed. (See Chapter 8) ACR projects can follow internationally recognized approaches such as The World Bank Safeguard Policies, or can be combined with the Climate Community and Biodiversity Alliance (CCBA) Standard or the Social Carbon Standard for the assessment, monitoring, and reporting of environmental and community impacts. Project Proponents shall disclose in their Annual Attestations any negative environmental or community impacts or claims thereof and the appropriate mitigation measure. ACR reserves the right to refuse to list or issue credits to a project based on community or environmental impacts that have not or cannot be mitigated, or that present a significant risk of future negative environmental or community impacts.

CHAPTER 4: ADDITIONALITY

ACR's additionality requirements are intended to ensure that credited offsets exceed the GHG reductions and removals that would have occurred under current laws and regulations, current industry practices, and without carbon market incentives. Project Proponents must demonstrate that the GHG emission reductions and removals from an offset project are above and beyond the "business as usual" scenario. To qualify as additional, ACR requires every project:

- Either to exceed an approved performance standard, as defined in the applicable methodology, and a regulatory additionality test; or
- To pass a three-prong test of additionality.

4.A THREE-PRONG ADDITIONALITY TEST

This approach combines three tests that help determine whether GHG emission reductions and removals from an offset project are above and beyond the "business as usual" scenario. This does not mean the Project Activity delivers no financial or other benefits other than GHG reduction; it simply attempts to ascertain whether GHG reduction was a significant factor.

The three-prong test requires projects to demonstrate that they exceed currently effective and enforced laws and regulations; exceed common practice in the relevant industry sector and geographic region; and face at least one of three implementation barriers (financial, technological, or institutional). The three-prong test is described in Table 3 on the next page. The GHG Project Plan must present a credible demonstration, acceptable to ACR and the VVB, that the project passes these tests.

Some ACR-approved methodologies require application of an additionality tool to assist Project Proponents in demonstrating additionality. ACR does not require all methodologies to mandate application of an additionality tool; however, if the relevant methodology requires one, its use is mandatory, unless otherwise indicated by the ACR-approved conditions for use of the methodology.[11]

[11] An example is some CDM methodologies approved by ACR.

Table 3: Three-Prong Additionality Test

TEST	KEY QUESTIONS
REGULATORY SURPLUS	Is there an existing law, regulation, statute, legal ruling, or other regulatory framework in effect as of the project Start Date that mandates the Project Activity or effectively requires the GHG emissions reductions? **YES = FAIL NO = PASS**
COMMON PRACTICE	In the field or industry/sector, is there widespread deployment of this project, technology, or practice within the relevant geographic area? **YES = FAIL NO = PASS**
IMPLEMENTATION BARRIERS	**CHOOSE ONE OF THE FOLLOWING THREE**
Financial	Does the project face capital constraints that carbon revenues could address; or is carbon funding reasonably expected to incentivize the project's implementation; or are carbon revenues a key element to maintaining the project action's ongoing economic viability after its implementation? **YES = PASS NO = FAIL**
Technological	Does the project face significant technological barriers such as R&D deployment risk, uncorrected market failures, lack of trained personnel and supporting infrastructure for technology implementation, or lack of knowledge on practice/activity, and are carbon market incentives a key element in overcoming these barriers? **YES = PASS NO = FAIL**
Institutional	Does the project face significant organizational, cultural, or social barriers to implementation, and are carbon market incentives a key element in overcoming these barriers? **YES = PASS NO = FAIL**
If the project passes the Regulatory Surplus and Common Practice tests and at least one Implementation Barrier test, ACR considers the project additional.	

4.A.1 Regulatory Surplus Test

The regulatory surplus test requires the Project Proponent to evaluate existing laws, regulations, statutes, legal rulings, or other regulatory frameworks that directly or indirectly affect GHG emissions associated with a project action or its baseline candidates, and which require technical,

performance, or management actions. These legal requirements may require the use of a specific technology, meeting a certain standard of performance (e.g., new source performance standards), or managing operations according to a certain set of criteria or practices (e.g., forest practice rules). In determining whether an action is surplus to regulations, the Project Proponent does not need to consider voluntary agreements without an enforcement mechanism, proposed laws or regulations, optional guidelines, or general government policies.

Projects that are deemed regulatory surplus are considered surplus for the duration of their Crediting Period. If regulations change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal, but does not affect its additionality during the current Crediting Period, unless otherwise specified in the project-specific methodology. AFOLU projects with easements need to consider the legally binding requirements of the easement if the recordation date is within 1 year of the project Start Date. (The constraints outlined in the easement would also need to be included in the baseline scenario within this time frame.)

4.A.2 Common Practice Test

The common practice test requires the Project Proponent to evaluate the predominant technologies or practices in use in a particular industry, sector, and/or geographic region, as determined by the degree to which those technologies or practices have penetrated the market, and demonstrate that the proposed Project Activity is not common practice and will reduce GHG emissions below levels produced by common technologies or practices within a comparable environment (e.g., geographic area, regulatory framework, investment climate, access to technology/financing).

The level of penetration that represents common practice may differ between sectors and geographic areas, depending on the diversity of baseline candidates. The common practice penetration rate or market share for a technology or practice may be quite low if there are many alternative technologies and practices. Conversely, the common practice penetration rate or market share may be quite high if there are few alternative technologies or practices. Projects that are “first of its kind” are not common practice.

Projects that are deemed to go beyond common practice are considered as such for the duration of their Crediting Period. If common practice adoption rates of a particular technology or practice change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal; however, this does not affect its additionality during the current Crediting Period.

Note that the common practice test, a component of the three-prong test, is distinct from a performance standard. For some activities, the data used to define common practice in a particular industry, sector, or region may be functionally equivalent to the data required to establish an acceptable practice-based performance standard. In such cases, Project Proponents may elect the option to demonstrate additionality by defining a practice-based performance standard and demonstrating that the Project Activity both exceeds this standard and is surplus to regulations.

4.A.3 Implementation Barriers Test

An implementation barrier represents any factor that would prevent the adoption of the Project Activity the Project Proponent proposes. Generally, there are no barriers to the continuation of current activities, exceptions being regulatory or market changes that force a shift in a Project Activity or the end of equipment's useful lifetime.

Under the implementation barriers test, Project Proponents shall choose at least one of three barrier assessments (financial, technological, or institutional). Project Proponents may demonstrate that the Project Activity faces more than one implementation barrier, but are not required to address more than one barrier.

- **FINANCIAL BARRIERS** include high costs, limited access to capital, or an internal rate of return in the absence of carbon revenues that is lower than the Project Proponent's established and documentable minimum acceptable rate. Financial barriers can also include high risks such as unproven technologies or business models, poor credit rating of project partners, and project failure risk. If electing the financial implementation barrier test, Project Proponents shall include solid quantitative evidence such as net present value and internal rate of return calculations.
- **TECHNOLOGICAL BARRIERS** include R&D deployment risk, uncorrected market failures, lack of trained personnel and supporting infrastructure for technology implementation, and lack of knowledge on practice/activity.
- **INSTITUTIONAL BARRIERS** include institutional opposition to technology implementation, limited capacity for technology implementation, lack of management consensus, aversion to upfront costs, and lack of awareness of benefits.

4.B PERFORMANCE STANDARD APPROACHES

In lieu of the three-prong test, ACR also recognizes the "performance standard" approach, in which additionality is demonstrated by showing that a proposed Project Activity is (1) surplus to regulations, and (2) exceeds a performance standard as defined in an approved methodology.

Project Proponents must first establish regulatory additionality per the requirements in section A.1 of this chapter.

Second, under the performance standard approach, projects are required to achieve a level of performance that, with respect to emission reductions or removals, or technologies or practices, is significantly better than average compared with similar recently undertaken practices or activities in a relevant geographic area.[12] The performance threshold may be:

- **PRACTICE-BASED,** developed by evaluating the adoption rates or penetration levels of a particular practice in a relevant industry, sector, or sub-sector. If these levels are sufficiently low that it is determined the Project Activity is not common practice, then the activity is

[12] Adapted from the U.S. Environmental Protection Agency Climate Leaders offset methodologies at http://www.epa.gov/stateply/resources/optional-module.html.

considered additional. Specific thresholds may vary by industry, sector, geography, and practice, and are specified in the relevant methodology.

- **TECHNOLOGY STANDARD:** Installation of a particular GHG-reducing technology may be determined to be sufficiently uncommon that simply installing the technology is considered additional.
- **EMISSIONS RATE OR BENCHMARK** (e.g., tons of CO_2e emission per unit of output) with examination of sufficient data to assign an emission rate that characterizes the industry, sector, subsector, or typical land management regime, the net GHG emissions/removals associated with the Project Activity, in excess of this benchmark, may be considered additional and credited.

Performance standard baselines specific to particular project types, activities, and regions will be detailed in the relevant ACR-approved methodologies.

CHAPTER 5: PERMANENCE

In GHG accounting, permanence refers to the perpetual nature of GHG removal enhancements (or avoided emissions from conversion) and the risk that a project's atmospheric benefit will not be permanent. GHG emissions reductions from terrestrial sources and sinks may not be permanent if a project has exposure to risk factors such as intentional or unintentional events that result in emissions into the atmosphere of stored or sequestered CO_2e for which offset credits were issued (termed a Reversal). Impermanence is not an issue for some project types for which the GHG reductions or avoidance are not reversible once they occur. However, terrestrial and geologic sequestration and avoided conversion projects have the potential for GHG reductions and removals to be reversed upon exposure to risk factors, including unintentional reversals (e.g., fire, flood, and insect infestation for terrestrial projects, and unanticipated releases of CO_2 for geologic projects) and intentional reversals (e.g., landowners or Project Proponents choosing to discontinue AFOLU Project Activities and/or participate in an activity that reverses the sequestration previously achieved by a carbon sink, and for geologic sequestration, the release of stored CO_2 that is intentional or that is a collateral effect of any planned activities affecting the storage volume).

ACR AFOLU projects must commit to maintain, monitor, and verify Project Activity for a Minimum Project Term of 40 years. The Minimum Project Term is not equated with the assurance of permanence, because no length of time, short of perpetual, is truly permanent, nor is there a sound scientific basis or accepted international standard around any number of years that equates to an emission reduction/removal being permanent. Only well-designed reversal risk mitigation mechanisms can make sequestration-based offsets effectively permanent and fungible with permanent offsets. Assessment and mitigation of reversal risk ensures that any losses of sequestration (i.e., increases in atmospheric GHG concentrations), whether occurring from an unforeseen natural disturbance or from an intentional discontinuation of sequestration activities, are effectively compensated and the atmosphere "made whole."

ACR requires that projects with a risk of reversals shall assess and mitigate risk, and monitor, report, and compensate for reversals.

5.A ASSESSMENT OF RISK

Project Proponents of terrestrial sequestration and avoided conversion projects with a risk of reversal must conduct a reversal risk assessment using an ACR-approved tool that addresses both general and project-specific risk factors. General risk factors include financial failure, technical failure, management failure, rising land opportunity costs, regulatory and social instability, and natural disturbances. Project-specific risk factors vary by project type.

AFOLU Project Proponents shall conduct their risk assessment using the ACR Tool for Risk Analysis and Buffer Determination. The output of the tool is an overall risk-rating percentage for the project, translating into a number of offsets that must be deposited in the ACR Buffer Pool Account to mitigate the risk of reversal, the Minimum Buffer Percentage.

The risk assessment, overall risk category, Minimum Buffer Percentage, and calculated Buffer Contribution amount shall be included in the GHG Project Plan and Monitoring Report. ACR evaluates the proposed overall risk category and corresponding buffer contribution, and the VVB evaluates whether the risk assessment has been conducted correctly. Concurrent with each issuance of offsets to the project, the Project Proponent shall contribute offsets to the Buffer Account equal to the sum of the Minimum Buffer Percentage multiplied by each of the annual volumes of offsets being issued.

If no reversals occur, the project's risk category and Minimum Buffer Percentage may remain unchanged for 5 years. The risk analysis must be re-evaluated at least every 5 years, or coincident with site visit verification. An exception is in the event of a reversal, in which case the project baseline, risk category, and Minimum Buffer Contribution shall be immediately re-assessed and re-verified.

5.B REVERSAL MITIGATION, REPORTING, AND COMPENSATION

Project Proponents of AFOLU projects with risk of reversal shall enter into a legally binding Reversal Risk Mitigation Agreement with ACR/Winrock that allows them to select a reversal risk mitigation mechanism and details the requirements for reporting and compensating reversals. Should reversals occur the requirements and liabilities associated with replacing lost ERTs rest with the Project Proponent, and not necessarily with the individual land owner(s) per the Risk Mitigation Agreement.

5.B.1 Primary AFOLU Risk Mitigation Mechanism: The ACR Buffer Pool

Project Proponents choosing the ACR Buffer Pool as the risk mitigation mechanism agree to the ACR Buffer Pool Terms and Conditions (Exhibit 1), which detail the operation of the Buffer Pool and requirements of the Project Proponent. Generally, the project contributes to the Buffer Pool account the number of offsets as determined by the project-specific risk assessment in order to replace unforeseen losses. ACR has sole management and operational control over the offsets in the Buffer Pool.

5.B.2 Geologic Sequestration Risk Mitigation Mechanisms

For geologic sequestration projects, Project Proponents must contribute 10% of the project's offset credits to a Reserve Account, managed by ACR, from which offsets will be retired in the event of a reversal during the Project Term. The reversed quantity shall be measured and reported, verified, and compensated by retiring an equivalent volume of offset credits from the Reserve Account. Reversals post-Project Term are compensated as outlined in the legally binding Risk Mitigation Covenant, filed in the real property records of each county, parish, and other

governmental subdivision that maintains real property records, which prohibits any intentional reversal unless there is advance compensation to ACR.

5.B.3 Alternate Risk Mitigation Mechanisms

In lieu of making a Buffer Pool Contribution or Reserve Account Contribution, Project Proponents may propose an insurance product for ACR approval as a risk mitigation mechanism. Insurance may be a financial product based on an actuarial analysis of project risk that considers circumstances such as the region, threats, and mitigating factors. This is similar to the assessment done for property insurance.

The Project Proponent may provide insurance, bonds, letters of credit, or other financial assurances to ACR in amounts, and in form and substance, satisfactory to ACR in its sole and absolute discretion. Such financial products must assure provision of sufficient funds to ACR, in the event a project suffers an unintentional or intentional reversal of sequestered carbon, to purchase and retire a number of ERTs sufficient to offset such reversal. There may be no hidden costs, exclusions, or unanticipated liabilities. ACR must approve the proposed alternative after it conducts due diligence, which will be at the Project Proponent's or insurance provider's expense.

5.C MONITORING FOR REVERSALS

All projects must adhere to ongoing monitoring requirements as detailed in relevant methodologies, including ongoing verification during the Minimum Project Term.

For Geologic Sequestration, Project Proponents are required to demonstrate that the CO_2 captured and stored is permanently sequestered underground through detailed post-injection monitoring, required until it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled failure scenarios indicate that the CO_2 will remain contained within the storage volume. The Risk Mitigation Agreement details ongoing monitoring requirements.

5.D REVERSAL REPORTING AND COMPENSATION

AFOLU reversals must be reported and compensated following requirements detailed in the ACR AFOLU Carbon Project Reversal Risk Mitigation Agreement and the Buffer Pool Terms and Conditions. Geologic sequestration reversals must be reported and compensated following requirements as detailed in applicable methodology. In the event of reversals during the project term, the quantity shall be measured and reported, verified, and compensated by retiring offset credits from the Reserve Account. Reversals post-Project Term are compensated as outlined in the Risk Mitigation Covenant, which prohibits any intentional reversal unless there is advance compensation to ACR.

CHAPTER 6: PROJECT DEVELOPMENT TRAJECTORY

Every project submitted for registration must use an ACR-approved methodology. This chapter focuses on the project development steps that occur after the methodology has been approved: Project listing, validation and verification, and issuance of ERTs.

6.A PROJECT DEVELOPMENT PROCESS

A Project Proponent using an ACR-approved methodology shall proceed per the following sequence of steps:

1. Project Proponent submits a GHG Project Listing Form using the template found at www.americancarbonregistry.org.
2. ACR reviews the GHG Project Listing Form for completeness, and a compatibility check with the ACR Standard, at fees per the currently published ACR fee schedule.[13] This screening results in (a) Project Listing with approval to proceed to Validation/Verification Body (VVB) selection, (b) requests for clarifications or corrections, or (c) rejection because the project is ineligible or does not meet requirements of the ACR Standard. If the ACR screening includes requests for clarifications or corrections, the Project Proponent may re-submit the GHG Project Listing Form for further review. ACR reserves the right to accept or reject a GHG Project Listing at any time and for any reason during the review. A project is considered to be listed once the GHG Project Listing Form is approved. The project listing information and form will then be made public on ACR.
3. Having received listing approval to proceed to VVB selection, the Project Proponent selects an ACR-approved independent third-party VVB to validate the GHG Project Plan and verify the Project's GHG assertions for the first reporting period as presented in the monitoring report. The VVB shall submit to ACR a Conflict of Interest self-evaluation form for review. ACR must approve the VVB selection prior to the start of validation and verification services based on proper accreditation, conflict of interest review, and VVB rotation requirements.
4. Validation and the first verification may occur simultaneously and must occur prior to issuance of ERTs. Fees for validation and verification are as agreed between the Project Proponent and verifier. This results in submission to ACR of a validated GHG Project Plan, verified monitoring report, validation report, verification report, and verification statement.

[13] The ACR fee schedule is posted at www.americancarbonregistry.org.

5. ACR reviews the project, validation and verification documents. This results in (a) acceptance, (b) acceptance contingent on requested corrections or clarifications, or (c) rejection. See ACR Validation and Verification Standard for further details.
6. Upon acceptance of the submitted documents, ACR registers the project and makes the final validated GHG Project Plan, verified monitoring report, validation report, and verification report and statement public on its registry.
7. ACR issues to the Project Proponent's account serialized ERTs for the relevant reporting period, in the amount listed in the verification statement. The vintage year of the ERTs correspond to the year the emissions reductions or removals occurred. In the case of a terrestrial or geologic sequestration project, ACR simultaneously deposits the appropriate number of ERTs into the ACR Buffer Pool, if this is the risk management option the Project Proponent has chosen.
8. Next steps are at the Project Proponent's discretion—offset transfer, retirement, etc.—with activation, transaction, cancellation, and retirement fees per the currently published ACR fee schedule.
9. Subsequent reporting periods qualifying within the originally validated crediting period can be verified per ACR's Validation and Verification Standard, and be tied to the same GHG Project Plan.

6.B INFORMATION IN A GHG PROJECT PLAN

A GHG Project Plan is a document that describes the Project Activity; addresses ACR eligibility requirements; identifies sources and sinks of GHG emissions; establishes project boundaries; describes the baseline scenario; defines how GHG quantification will be done and what methodologies, assumptions, and data will be used; and provides details on the project's monitoring, reporting, and verification procedures. The GHG Project Plan shall use the ACR template and include the following information:

- Project title, purpose(s), and objective(s);
- Type of GHG project;
- Project location, including geographic and physical information allowing for the unique identification and delineation of the specific extent of the project. Projects implementing a Programmatic Design Approach shall include location information for all sites known at the time of the GHG Project Plan validation;
- Physical conditions prior to project initiation;
- Description of how the project will achieve GHG emission reductions and/or removal enhancements;
- Project technologies, products, services, and expected level of activity;
- Ex ante projection of estimated GHG emission reductions and removal enhancements, stated in metric tons of CO_2e;
- Identification of risks that may substantially affect the project's GHG emission reductions or removal enhancements;

- Roles and responsibilities, including contact information of the Project Proponent, other project participants, relevant regulator(s) and/or administrators of any GHG program(s) in which the GHG project is already enrolled, and the entities holding offset title and land title;
- Information relevant to the eligibility of a GHG project and quantification of GHG emission reductions or removal enhancements, including legislative, technical, economic, sectoral, socio-cultural, environmental, geographic, site-specific, and temporal information;
- Relevant outcomes from any stakeholder consultations and mechanisms for ongoing communication, as applicable;
- Chronological plan for initiating Project Activities, project term, frequency of monitoring, reporting, and verification, including relevant Project Activities in each step of the GHG project cycle;
- Notification of relevant local laws and regulations related to the project and a demonstration of compliance with them;
- Statement whether the project has applied for and been listed, registered, and/or been issued GHG emission reduction or removal credits through any other GHG emissions program, including detailed information on any credit issuance (volume, vintage, status), and information on any rejections of the project application, as applicable (see 6.C below);
- An environmental and community impact assessment, following ACR requirements, to ensure compliance with best practices and that safeguard measures are in place to avoid, mitigate, or compensate potential negative impacts, and how such measures will be monitored, managed, and enforced; and
- Identification and description of the Sustainable Development Goals to which the project impacts are aligned and positively contribute.

Project Proponents shall use the GHG Project Plan template available at www.americancarbon-registry.org.

6.C PREVIOUS REJECTION BY A GHG SYSTEM

ACR may consider a project rejected by other voluntary or compliance GHG programs, due to procedural or eligibility requirements, if the project complies with all aspects of the ACR Standard and any relevant sector standard. The Project Proponent for such a project shall:

1. Include a statement in the GHG Project Plan that lists all other programs to which the Project Proponent has applied for registration, was rejected, and the reason(s) for the rejection. Such information shall not be considered Commercially Sensitive Information.
2. Provide the actual rejection document(s), including any additional explanation, to ACR and its verifier.

6.D PROJECT DEVIATIONS

ACR will permit project-specific deviations to an existing approved methodology where they do not negatively affect the conservativeness of an approved methodology's approach to the quantification of GHG emissions reductions and removal enhancements. For instance, where alternate monitoring or measurement regimes are proposed, ACR may permit these changes provided they are conservative. ACR will not permit, on a project-specific basis, changes to requirements related to additionality assessment or baseline establishment.

Project Proponents shall submit any proposed project-specific methodology deviation to ACR for review and approval. Deviations apply for that specific project but are not published as modifications to the methodology. Project Proponents must provide evidence that the proposed deviation, such as a substitute calculation method for missing data, is conservative (i.e., likely to underestimate net GHG reductions or removal enhancements).

Project Proponents shall request a project-specific deviation by using the Methodology Deviation template available at www.americancarbonregistry.org.

6.E PROJECT MONITORING REPORTS

Project monitoring reports shall be completed for each verified reporting period using the template for Project Monitoring Report available at www.americancarbonregistry.org. The monitoring report shall be submitted to the approved VVB during verification and submitted to ACR upon completion of the verification, including any corrections/revisions identified by the VVB. The report shall describe the current status of project operation, and include the data monitored and monitoring plan, and the calculated emission reductions for the reporting period. Additionally, project monitoring reports shall describe any project-specific deviations that may have occurred during the reporting period, as described below.

Changes to validated GHG Project Plans are not permitted. Instead, project-specific deviations from methodology requirements or other changes from the validated GHG Project Plan (e.g., new GHG sources, sinks, or reservoirs) must be described in a Project Monitoring Report—as well as all subsequent Project Monitoring Reports—and submitted during the project's subsequent verification. As described in Section 6.D above, ACR must pre-approve any project-specific deviation from methodology requirements. Where changes to GHG Project Plans require revisions to baseline or additionality assessments, these changes must be validated at the time of the subsequent verification.

6.F AGGREGATION AND PROGRAMMATIC DEVELOPMENT APPROACH

ACR has established procedures for projects to include multiple facilities, fields, or parcels (hereafter referred to collectively as "sites") as an Aggregated Project or as a Programmatic Development Approach (PDA) so that they may achieve efficiencies of-scale and other potential project administrative benefits while preserving the accounting principles of the ACR Standard and its approved methodologies, and the integrity of the monitoring, reporting and verification processes. Streamlined processes associated with documentation, registration and verification of multiple project sites may be available to projects applying these approaches.

6.F.1 Aggregation

A Project Proponent proposing an Aggregated Project shall submit a GHG Project Plan encompassing all project sites, and applying project boundaries, baseline definition, additionality demonstration, and all other requirements at the level of the Aggregate. No new sites can be added after the initial validation. An Aggregated Project shall:

- Be under the management of a single Project Proponent and registered under a single ACR account.
- Implement a single ACR-approved methodology (or pair of ACR-approved methodologies when relevant[14]).
- Adhere to a single overarching project Start Date, which corresponds to the earliest Implementation Date among the sites.
- If an environmental impact analysis is required by the methodology, provide confirmation of compliance with any applicable analysis requirements, unless the analysis was undertaken for the whole Aggregated Project and applies equally to each site.
- If public consultation from stakeholders is required by the methodology, provide information on how comments by local stakeholders were invited, a summary of any comments received and how due account was taken of any comments received, unless the comments were sought for the whole Aggregated Project and apply equally to each site.
- Where relevant, the Project Proponent should pursue the ACR Standard requirements for precision (±10% of the mean at a 90% confidence level) at the Aggregated Project level for the purposes of monitoring and verification.
- Assess general and project-specific risk factors for an Aggregated Project as for any other project. The risk rating is applied at the overall Aggregate;
- Adhere to the Crediting Period requirements of the chosen methodology with each site able to report and verify GHG emissions reductions for the duration of its individual Crediting

[14] Some ACR-approved methodologies may be paired to be used simultaneously on the same project area. This allowance will be specified in the methodologies themselves.

Period. However; upon any request for a renewed Crediting Period all sites must be included in an updated GHG Project Plan and be re-validated at the same time.

If the Project Proponent anticipates adding more project sites after the initial validation, they should instead register using the Programmatic Development Approach (PDA), described on the next page.

6.F.2 Programmatic Development Approach

The PDA provides for organization of project participants around basic similarity criteria and a common project Start Date but with flexibility for sites to enter the project at different times. The PDA is intended for projects where the participation of all project participants or sites is impractical at the time of initial validation. Although this approach allows for new project participants and sites to enter over time, it does require more complex project management and verification considerations than an Aggregated Project approach, in which all project participants and sites are included in the project's initial validation.

6.F.2.1 GENERAL PDA REQUIREMENTS:

- A PDA project will be under the management of a single Project Proponent and listed under a single ACR account.
- A PDA project will implement a single ACR-approved methodology (or pair of ACR-approved methodologies, when relevant[15]).
- The Project Proponent shall assess general and project-specific risk factors for a PDA project as for any other project. The risk rating is applied at the overall PDA level.
- A PDA project will adhere to a single overarching project Start Date, which corresponds to the earliest Implementation Date among the sites included in the first validation. All sites participating in the PDA project must have a site-specific Implementation Date that is the same or after the established project Start Date.
- A site or group of sites will be considered "participating" in the PDA project upon its successful validation by an ACR-approved VVB;
- A group of sites undergoing validation and entering the project at the same time is considered a "cohort." Multiple cohorts may enter the project during the same validation, and may be organized along various site characteristics (e.g., location, quantification approach) to try to facilitate verification efficiencies.
- Sites within a cohort must be on the same validation and verification schedule.
- The Crediting Period requirements of the chosen methodology can be applied at the site level where the project may report and verify GHG emissions reductions for the duration of each site's individual Crediting Period; however, upon request for a renewed Crediting Period

[15] Some ACR-approved methodologies may be paired to be used simultaneously on the same project area. This allowance will be specified in the methodologies themselves.

at any site, an updated GHG Project Plan must be submitted and the project re-validated for all participating sites at the same time.

- If the chosen methodology is no longer approved for use by ACR, new sites cannot be added to the PDA project. Existing sites can continue report and verify for the duration of their own Crediting Periods.
- If a new version of the chosen methodology has been published, new sites may continue to be added to the same PDA project only after an updated GHG Project Plan is submitted and the project is re-validated using the most recent version of the methodology.
- The GHG Project Plan shall specify the programmatic boundaries (geographic, temporal, and GHG assessment boundary), a baseline scenario, and a monitoring/verification plan for the entire PDA (i.e., for the initial and future participating sites), to include a proposed recruitment schedule for future sites to be enrolled in the project. It must also include the site-specific details for at least one enrolled project site upon listing.
- The Project Proponent must describe in the GHG Project Plan a management system that includes the following:
  - The reason why all expected project participants and sites cannot be included upon initial validation;
  - A clear definition of the roles and responsibilities of personnel involved in the process of inclusion of new sites;
  - A description of the principles that will be applied to recruit new sites to the program;
  - Procedures to avoid double counting that no site or group of sites has been or will be registered on ACR as part of another project; and
  - A records and documentation control process for each site, made available to the VVB at the time of validation.
- Each site must undergo validation by an ACR-approved VVB before ERTs can be issued against its associated Project Activities. This may be conducted at the same time as a full verification for the whole project, and in addition to desk-based review for each new site, must include site visits to a selection of the new sites, to the extent required by the chosen methodology and as determined by the VVB's sampling proceedures.

6.F.2.2 EACH SITE PARTICIPATING IN A PDA PROJECT MUST:

- Meet all project eligibility criteria as determined by the ACR Standard and chosen methodology.
- Be enrolled by the Project Proponent no later than 5 years after the site's Implementation Date. The enrollment date is the date upon which the project participant and Project Proponent agree to enter the site into the PDA project. Dated documentation of the agreement must be provided to the VVB for validation.
- Be available for a site visit during the validation and any subsequent verification where site visits are required. VVBs may use equal probabilities among sites to select which will receive validation and verification site visits, or a risk- or sensitivity-based analysis to identify those sites with the strongest influence over a project's overall carbon reduction estimates. (Not all sites must undergo a site visit at each required interval.) VVBs must use their own discretion

to determine if a cohort lends itself to sub-sampling. All project sites are subject to desk-based review at minimum.

- Be described in a single, consolidated PDA Project Design Document, which shall be considered an addendum to the GHG Project Plan. The PDA Project Desgin Document shall outline the unique attributes of the site(s) enrolled at project listing, and be updated as new sites are added, to include the following:
  - A clearly defined geographic boundary to uniquely identify the site, including maps and spatial files as required by the chosen methodology;
  - A description of the Project Activities carried out on the site;
  - Name/contact details of the entity/individual responsible for the operation of each site;
  - The site-specific Implementation Date and confirmation that the Implementation Date of any site is not, or will not be, prior to the project's Start Date;
  - Information on how the site fulfills the eligibility criteria of the ACR Standard and chosen methodology, is within the project boundaries, and demonstration of additionality as specified in the GHG Project Plan;
  - Calculations of baseline emissions and estimated net emission reductions or removal enhancements; and
  - Confirmation of the date of enrollment as demonstrated by agreement between the project participant and the Project Proponent.
- Provide the information required in the monitoring report during each verification. This information can be consolidated into a single summary report to facilitate easier review across all participating sites.
- If the methodology requires an environmental impact analysis, provide confirmation of compliance with any applicable analysis requirements, unless the analysis was undertaken for the whole PDA project and applies equally to each site.
- If the methodology requires public consultation from stakeholders, provide information on how local stakeholders' comments were invited, a summary of any comments received, and how due account was taken of any comments received, unless the comments were sought for the whole PDA project and apply equally to each site; and
- If defined by the chosen methodology, meet the required inventory statistical precision (±10% at 90% confidence interval) for the CO_2e estimate reported in the monitoring report.

6.F.3 Design Considerations for Aggregates and PDA Cohorts

Project Proponents may be able to increase the efficiencies around reporting and verification by strategically designing the groups of sites participating in an Aggregated Project or PDA. To maximize such potential efficiencies, sites should be grouped so their defining characteristics are as homogeneous as possible. VVBs may use equal probabilities among sites to select which will receive verification site visits, or a risk- or sensitivity-based analysis to identify sites with the strongest influence over a project's overall carbon reduction estimates. VVBs must use their own discretion to determine if a cohort or Aggregate lends itself to sub-sampling. All project

sites are subject to desk-based review at minimum. Below are some examples of how variation in site characteristics may be minimized in an aggregate or cohort.

- Homogenous project practices or technologies are implemented, to the extent there are multiple options within the chosen methodology.
- Use of a single quantification approach for the baseline and project conditions (models, equations, measurements, default factors) as outlined in the methodology. These methods shall be documented in the GHG Project Plan. Any subsequent changes to these methods following the initial validation of the GHG Project Plan must be applied across all sites in the cohort to maintain any achieved efficiencies, tracked, and made available for review at succeeding third-party verification events to ensure the quality and conservativeness of carbon accounting principles originally validated for the project are maintained.
- For AFOLU projects only: Sites are located within a pre-defined geographic region, such that all fall within a maximum of three ecoregions, defined by the World Wildlife Foundation (2014) as "A large unit of land or water containing a geographically distinct assemblage of species, natural communities, and environmental conditions. The boundaries of an ecoregion are not fixed and sharp, but rather encompass an area within which important ecological and evolutionary processes most strongly interact."[16]
  - To determine the ecoregion of each participating site located in the United States, please refer to U.S. Forest Service maps at http://www.fs.fed.us/land/ecosysmgmt/index.html.
  - To determine the ecoregion of each international participating site outside the United States, please refer to the World Wildlife Federation delineation of ecoregions at http://www.worldwildlife.org/biomes.
- For AFOLU projects only: Sites encompass relatively similar forest land or soil types.
- Sites share a similar baseline scenario in which there are the same legal constraints (i.e., the without-project scenario is comparable).
- For methodologies that require direct measurements, stratification and organizing projects along some of the characteristics above will help make the precision target (±10% of the mean at a 90% confidence level), which shall be applied at the Aggregate or cohort level for the purposes of monitoring and verification, achievable at reasonable sampling costs.

6.G COMMERCIALLY SENSITIVE INFORMATION

Project Proponents may designate certain parts of the GHG Project Plan or other project documentation as Commercially Sensitive Information. This information must be available for review by ACR and the VVB (with non-disclosure agreements, as necessary), but will be excised from the project documentation posted publicly on the ACR registry.

For the sake of transparency, ACR shall presume project information to be available for public scrutiny, and demonstration to the contrary shall be incumbent on the Project Proponent. At a

[16] WWF, 2014. http://wwf.panda.org/about_our_earth/ecoregions/about/what_is_an_ecoregion/.

[17] Note: The geographic boundaries may be further constrained for projects where the chosen methodology requires regional-specific factors in the establishment of the baseline.

minimum, ACR shall disclose publicly the project baseline scenario, calculations, monitoring report, and additionality assertion. The VVB shall check that any information requested as "commercially sensitive" meets the ACR definition of Commercially Sensitive Information.

6.H ADDITIONAL PROJECT DOCUMENTATION FOR REGISTRATION

ACR may require the following documentation as part of the project review prior to registration:

- Title documents or sample landowner agreements;
- Chain of custody documentation, if applicable; and
- ACR-Proponent agreement governing Buffer Pool obligations, if applicable.

To support the GHG Project Plan's declaration of title, ACR may require one or more of the following: a legislative right; a right under local common law; ownership of the plant, land, equipment and/or process generating the reductions/removals; or a contractual arrangement with the owner of the plant, land, equipment, or process that grants offset title to the Project Proponent.

6.I CREDITING PERIOD RENEWAL

All projects have a limited Crediting Period (i.e., the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario).

In general, the Crediting Period for non-AFOLU projects is 10 years, unless otherwise specified in the relevant ACR sector requirements or approved methodology. Crediting periods for AFOLU projects vary and are specified in the relevant sector requirements and/or methodology.

A Project Proponent may apply to renew the Crediting Period by:

- Re-submitting the GHG Project Plan in compliance with then-current ACR standards and criteria;
- Re-evaluating the project baseline, as required by the methodology;
- Demonstrating additionality against then-current regulations, common practice, and implementation barriers (or against an approved performance standard and then-current regulations), as required by the methodology;
- Using ACR-approved baseline methods, emission factors, tools, and methodologies in effect at the time of Crediting Period renewal; and,

- Completing validation of the new GHG Project Plan within one year from the end of the previous crediting period.[18]

ACR does not limit the allowed number of renewals, since at each Crediting Period renewal the Project Proponent must demonstrate that the project is additional and meets all ACR requirements. An acceptable validation report is necessary for ACR to renew the Crediting Period and continue issuing offsets generated by the project. Upon acceptance by ACR of the validation and verification documents, ACR will issue new ERTs each year (or more or less frequently, at the Project Proponent's request) for the duration of the new Crediting Period, provided the Project Proponent continues to meet the current ACR reporting and verification requirements.

On a project level, when a project seeks renewal of a Crediting Period (i.e., the previous was validated under a prior version of the ACR Standard or under a different GHG program and the project's Crediting Period has expired), the project is required to meet the requirements of the most recent version of the ACR Standard.

[18] ACR suggests that the Project Proponent conduct the validation of the re-submitted GHG Project Plan for the new Crediting Period concurrently with the last verification of the previous, expiring Crediting Period. ACR may on a case-by-case basis consider applications for crediting period renewal submitted beyond the one-year deadline for validation of the new GHG Project plan.

CHAPTER 7: METHODOLOGIES AND TOOLS

If ACR has not yet published a methodology for a particular project type, the Project Proponent has two options: request approval of a methodology developed under another GHG program or submit a new or modified methodology to ACR for approval. Any project proposing to use an ACR-approved methodology from another GHG program must comply with the ACR Standard.

7.A GHG MEASUREMENT TOOLS AND METHODOLOGIES

7.A.1 ACR-Published and CDM-Approved Methodologies

Current versions of methodologies published by ACR via the public consultation and peer review process are approved without qualification. Current versions of methodologies approved by the CDM Executive Board are generally approved for use; however, Project Proponents implementing projects under CDM methodologies must first have ACR's review, clarifications, and approval as described in 7.B.1 below to ensure compliance with ACR requirements at fees per the currently published ACR fee schedule.

7.A.2 Modifications to Existing Approved Methodologies

ACR may permit modifications to an existing ACR-approved methodology where they do not negatively affect the conservativeness of the methodology's approach to determining additionality and quantification of GHG emissions reductions and removal enhancements. Methodology modifications may be submitted for review by ACR, at fees per the currently published ACR fee schedule. ACR will review the extent of the modification and determine whether the internal review, public consultation, and peer review process, as described in Section B of this chapter, must be implemented. In general, if the extent of the proposed modification(s) necessitates the process described in Section B, a new version number for the methodology will be issued (e.g., Version 3.0 to Version 4.0). Modifications to eligibility, applicability, Project Activities, and/or baseline assumptions are likely to trigger the full process stipulated in Section B; minor modifications to correct quantification errors or provide clarification on monitoring requirements may not require the full process.

7.A.3 New Methodologies

New methodologies proposed to ACR for approval always require internal screening, public consultation, and blind scientific peer review as described in section B.

7.B ACR'S INTERNAL REVIEW, PUBLIC CONSULTATION, AND SCIENTIFIC PEER REVIEW PROCESS

The following process is applied to new methodologies developed internally by Winrock/ACR, methodologies drafted by external authors, and certain methodology modifications, per Section A.2 of this chapter. In such cases, ACR coordinates a process of internal review, public stakeholder consultation, and a blind scientific peer review. ACR administers this process, with fees charged to the methodology author.

1. The methodology developer(s) submits to ACR for review the following information: 1) Market analysis demonstrating technical potential for emissions reductions of the proposed activity and ability and timing to scale impact given geographic, regulatory or other market considerations; 2) Sample project using the proposed methodology including an economic analysis demonstrating that the proposed activity is viable under current market conditions; and 3) Indication of intent for near-term project development. Based on review of this information, ACR will determine whether to move forward with the methodology review.
2. The Project Proponent submits the proposed new or modified methodology to ACR. ACR has templates posted at www.americancarbonregistry.org for some proposed methodologies. Project Proponents must submit their proposed methodology using the available templates to reduce the time and cost of the approval process for both Project Proponent and ACR.
3. ACR screens the methodology against its requirements, communicates any corrections or clarifications that are immediately needed, and informs the methodology author of its judgment as to whether the methodology is ready for public consultation and peer review. ACR conducts this internal review at currently published fees.[19] If the methodology author elects to proceed, they address any corrections and clarifications identified in the ACR review and resubmit the methodology. ACR's agreement to proceed with the methodology approval process does not guarantee that the methodology will be approved.
4. ACR coordinates a public consultation process. The methodology is posted publicly on the ACR website for a minimum of 30 days, and ACR sends out a public notice inviting comments. During this period, the methodology authors may also elect to conduct a webinar with ACR to present the draft methodology and solicit additional comments.

[19] The ACR Methodology screening fee includes two rounds of ACR review. The fee will be charged again for any necessary additional reviews prior to the initiation of the public consultation process.

At the conclusion of the public comment period, ACR compiles all comments by methodology section and forwards a complied report to the methodology author, who then incorporates revisions and/or documents responses to each comment, which are posted on ACR's website.

5. The revised methodology is provided to a team of independent subject matter experts for a blind scientific peer review process. ACR may consult the relevant ACR Technical Committee in the selection of reviewers. The lead reviewer compiles comments and recommendations from the peer review team, and prepares a summary report. ACR delivers to the methodology author a peer review report, organized by section of the methodology, to which the author must respond by incorporating revisions and/or documenting justifications for the proposed approach. Generally, several rounds of peer review are necessary. Timing and cost of peer review depends on the complexity, scope, and quality of the methodology and the availability of peer reviewers. The cost of peer review is borne by the methodology author.
6. Once all required corrections have been made, ACR approves the new methodology and publishes it on its website. An approved methodology may be used by any Project Proponent, including the methodology author, in preparing GHG Project Plans and registering projects on ACR.
7. ACR posts process documentation—including all public comments and documented responses, and all peer review comments and documented responses—along with the public comment version of the methodology, and the final approved methodology.

Scientific peer review teams are selected from a pool of potential reviewers with applicable subject matter expertise. ACR actively identifies and qualifies candidates for inclusion in this pool, and publicly solicits applications from interested parties. Applications are reviewed for sector expertise, GHG quantification experience, and impartiality. Throughout and after the peer review process, the experts selected for each review team remain unknown to the methodology author and the public.

7.C UPDATES TO ACR-APPROVED METHODOLOGIES AND TOOLS

ACR may periodically update (or decide to retire) its approved methodologies and tools. Such updates occur when significant changes to GHG accounting best practice or the legislative and/or regulatory context justify an update; when sufficient new data is available to revise eligibility and/or additionality requirements; when ACR becomes aware of clarifications that should be made; or for other reasons.

For methodologies that employ a performance standard for additionality assessment, ACR shall review the validity and underlying assumptions of the performance standard for all non-forestry projects every 5 years, at minimum. The period for forestry projects is every 10 years, at minimum.

7.D ROLES OF THE ACR TECHNICAL COMMITTEE(S)

ACR may periodically establish Technical Committees for particular sectors (e.g., AFOLU), to provide independent advice on methodology acceptance, methodology modifications and project deviations, selection of peer reviewers, and related issues. The responsibilities of the Technical Committees include the following:

- Review proposed new methodologies and tools submitted to ACR for approval;
- Advise ACR on the selection of appropriate peer reviewers for a proposed new methodology or methodology revision;
- Make final determinations in the event consensus on a particular methodological issue is not reached by the peer review team or between the peer reviewers and the methodology author;
- Advise ACR on continuous improvements to its AFOLU standards, including issuance of new versions at appropriate intervals; and
- Advise ACR on decisions to commission new methodologies and tools using internal resources.

ACR Technical Committees are constituted via calls for applications to select the most relevant experts.

CHAPTER 8: ENVIRONMENTAL AND COMMUNITY IMPACTS

ACR supports a diverse set of offset Project Activities, each with its own potential to generate both positive and negative environmental and social impacts. Positive impacts can contribute to sustainable development objectives; negative risks and impacts can be identified, evaluated, and managed through appropriate safeguard procedures.

ACR requires that projects adhere to environmental and community safeguards best practices to:

- Ensure that projects "do no harm" by maintaining compliance with local, national, and international laws and regulations;
- Identify environmental and community risks and impacts and contributions to sustainable development;
- Detail how negative environmental and community impacts will be avoided, reduced, mitigated, or compensated, and how mechanisms will be monitored, managed, and enforced;
- Ensure that the rights of affected communities and other stakeholders are recognized, and that they have been fully and effectively engaged and consulted; and
- Ensure that ongoing communications and grievance redress mechanisms are in place, and that affected communities will share in the project benefits.

8.A ENVIRONMENTAL AND COMMUNITY IMPACT ASSESSMENT REQUIREMENTS

As part of the GHG Plan, ACR requires all projects to prepare and disclose an environmental and community impact assessment. ACR does not require that a particular process or tool be used for the impact assessments as long as basic requirements are addressed, as detailed below. ACR projects can follow internationally recognized approaches, such as The World Bank Safeguard Policies, or can be combined with the Climate Community and Biodiversity Alliance (CCBA) Standard or the Social Carbon Standard for the assessment, monitoring and reporting of environmental and community impacts. Projects' environmental and community impacts should be net positive. Project Proponents shall include in their GHG Project Plan a description of project impacts on communities and the environment in the immediate project area. This shall include changes in community well-being due to the Project Activity and an evaluation of any negative impacts on community groups. Project Proponents shall base these estimates on defined and defensible assumptions about how the Project Activity will alter social and economic well-being, including potential impacts of changes in natural resources and ecosystem services identified as important by the communities, for the project duration. In the GHG Project Plan Project Proponents shall also identify and describe the Sustainable Development Goals to which those impacts are aligned and positively contribute.

The assessment should include the following:

1. An overview of the Project Activity and geographic location.
2. Applicable laws, regulations, rules, and procedures and the associated oversight institutions.
3. A description of the process to identify community(ies)[20] and other stakeholders[21] affected by the project and, as applicable, the community consultation and communications plan.
4. An assessment of the project's environmental risks and impacts, including factors such as climate change mitigation and adaptation, biodiversity, air quality, water quality, soil quality, and ozone quality, as well as the protection, conservation, or restoration of natural habitats such as forests, grasslands, and wetlands. The assessment shall: 1) identify each risk/impact; 2) categorize the risk/impact as positive, negative, or neutral and substantiate the risk category; 3) describe how any negative impacts will be avoided, reduced, mitigated, or compensated; 4) detail how risks and impacts will be monitored, and how often and by whom; and 5) describe how positive impacts contribute to sustainable development goals.
5. For community-based projects, an assessment of the project's community risks and impacts, including factors such as land and natural resource tenure, land use and access arrangements, natural resource access (e.g., water, fuelwood), food security, land conflicts, economic development and jobs, cultural heritage, and relocation. The assessment shall: 1) briefly describe the process to identify community risks/impacts; 2) identify each risk/impact; 3) categorize the risk/impact as positive, negative, or neutral, and substantiate the risk category; 4) provide detailed information regarding the community stakeholder consultation process (e.g., meeting minutes, attendees), including documentation of stakeholder comments and concerns and how those are addressed; 5) provide evidence of Free, Prior and Informed Consent for the Project Activity, as applicable; 6) provide evidence of no relocation or resettlement (voluntary or involuntary), as applicable; 7) describe how any negative project impacts will be avoided, reduced, mitigated, or compensated; 8) detail how risks/impacts will be monitored, and how often and by whom; 9) describe the mechanism for ongoing communications with the community and grievance mechanisms, as applicable; and 10) describe how positive impacts contribute to sustainable development goals.

[20] As defined by CCBA, a community includes all groups of people, including indigenous peoples, mobile peoples, and other local communities, who live within or adjacent to the project area, as well as any groups that regularly visit the area and derive income, livelihood, or cultural values from the area. This may include one or more groups that possess characteristics of a community, such as shared history, shared culture, shared livelihood systems, shared relationships with one or more natural resources (e.g., forests, water, rangeland, wildlife), and shared customary institutions and rules governing the use of resources.

[21] Other stakeholders are defined as groups other than communities that can potentially affect or be affected by the Project Activities and who may live within or outside the Project Zone.

8.B ONGOING DISCLOSURE AND ENFORCEMENT

In their Annual Attestations to ACR, Project Proponents shall disclose any negative environmental or community impacts or claims of negative environmental and community impacts and the appropriate mitigation measure.

ACR reserves the right to refuse to list or issue credits to a project based on community or environmental impacts that have not or cannot be mitigated, or that present a significant risk of future negative environmental or community impacts.

CHAPTER 9: VALIDATION AND VERIFICATION

This chapter provides a general overview of ACR requirements for validation of GHG Project Plans, and ex post verification of GHG assertions, by a competent and independent third-party VVB approved by ACR. Further detail on ACR verification requirements is included in the ACR Validation and Verification Standard, available at www.americancarbonregistry.org.

9.A DEFINITIONS

ACR conducts a preliminary listing review of every project. ACR may request clarifications and corrections regarding a proposed project's listing documentation before allowing a project to commence validation.

Validation is the systematic, independent, and documented process for the evaluation of a GHG Project Plan against applicable requirements of the ACR Standard and approved methodology.

Verification is the systematic, independent, and documented assessment by a qualified and impartial third party of the GHG assertion for a specific reporting period.

Validation and verification must be conducted by an ACR-approved independent third-party VVB. Validation and verification may be conducted by the same entity, and may occur simultaneously.

9.B MATERIALITY THRESHOLD

A material misstatement is an inaccurate assertion of an offset project's GHG emission reductions/removals, which may reasonably be expected to influence decisions or actions taken by the users of the GHG project information. To accept a verification statement, ACR requires that discrepancies between the emission reductions/removal enhancements claimed by the Project Proponent and estimated by the VVB be immaterial (i.e. less than ACR's materiality threshold of ±5%). Individual or aggregation of errors or omissions greater than the ACR materiality threshold require re-stating before a verification statement will be accepted.

ACR's materiality threshold also applies in the event that an overstated GHG emission reduction/removal assertion is discovered during a subsequent verification after it has been credited. If the misstatement exceeds the materiality threshold, the amount of over issuance shall be deducted from the net verified emissions reductions upon the next completed verification, cancelled from the project's ACR account, or be deducted from the project's contribution to the ACR Buffer Pool, to be replenished by the project account holder, as applicable.

The following equation is to be used to calculate the percent error in an emission reduction assertion:

Equation 1

$$\%\ \mathbf{Error} = \frac{\mathbf{Project\ Emission\ Reduction\ Assertion} - \mathbf{Verifier\ Emission\ Reduction\ Recalculation}}{\mathbf{Verifier\ Emission\ Reduction\ Recalculation}} \times \mathbf{100}$$

9.C VALIDATION AND VERIFICATION INTERVAL

Validation of the GHG Project Plan occurs once per Crediting Period. Renewal of the Crediting Period requires a new validation within one year from the end of the previous, expiring crediting period. Per Section 6.E, if project-specific changes that require revision to baseline or additionality assessments occur after the initial validation, these changes must be disclosed in the Project Monitoring Report and validated at the project's subsequent verification.

ACR requires verification of GHG assertions at specified intervals in order to issue new ERTs.[22] ERTs may be created and issued annually, or at the Project Proponent's request, more or less frequently. At each request for issuance of new ERTs, the Project Proponent must submit a verification statement from an approved verifier. No less than once every 5 years of reporting, and upon the first verification conducted by a new VVB (per ACR's VVB rotation requirements in Section 9.G), Project Proponents must submit a verification statement based on a full verification including a field visit to the project site.[23] This 5-year verification requirement begins on the date that the project is listed in the ACR. In the case of sequestration projects, the scope of this verification should include an updated assessment of risk of reversal and an updated buffer determination, as applicable.

9.D VALIDATION AND VERIFICATION BODY REQUIREMENTS

Verification is a risk-based process carried out in conformance with ISO 14064-3:2006 and ISO 14065:2013.[24] VVBs shall be accredited for project validation and verification in the sector of the applicable methodology, and shall meet the competence requirements as set out in ISO 14065:2013.

All VVBs must be approved by ACR and be accredited under ISO 14065 by an accreditation body that is a member of the International Accreditation Forum (IAF) and with which ACR has a

[22] Verification activities may begin only after the completion of the project's reporting period being verified.

[23] A field visit is required for validation and the first verification for the project. PDA projects are subject to risk-based sampling by the VVB to determine the number of site visits to be visited during a full verification. More information can be found in Chapter 10 of the ACR Validation and Verification Standard.

[24] ISO 14065:2013 references to "GHG programme" shall mean the ACR.

Memorandum of Understanding (MoU) in place, as detailed in the ACR Validation and Verification Standard.

A list of currently approved VVBs and the sectors for which they are approved to conduct validation and/or verification is provided at http://americancarbonregistry.org/carbon-accounting/verification.

Prior to commencing validation or verification work on ACR, all VVBs must be in good standing; have completed the application process described at http://americancarbonregistry.org/carbon-accounting/verification, including submitting an application form and Attestation of Validation/Verification Body, which details requirements for conflicts of interest and makeup of the verification teams; document technical capabilities for each of the sectoral scopes in which the verifier seeks to conduct validation or verification; established their VVB account on ACR; and have submitted a project-specific Conflict of Interest Form for ACR's approval.

9.E VERIFICATION REPORT AND STATEMENT

On completion of verification, the Project Proponent shall submit a verification report and verification statement to ACR. Verification documents shall be in English, and describe the verification process, any issues raised during the verification and their resolutions, and the conclusions reached by the VVB. The verification report shall:

- Describe the level of assurance of the verification statement;
- Describe the objectives, scope, and criteria of the verification against the ACR Standard and relevant sector standards;
- Describe whether the data and information supporting the GHG assertion were hypothetical, projected, and/or historical in nature;
- State the actual number of ERTs associated with the project-specific monitoring report that the verifier has verified;
- Include the GHG assertion, signed by the lead verifier;
- Include the verifier's conclusion on the GHG assertion, with any qualifications or limitations; and
- For projects requiring Project Proponents to assess risk of reversal and apply an ACR-approved risk reversal mitigation option, include the verifier's opinion on the risk assessment and adequate risk reversal mitigation.

More detail on contents of the verification report and statement is provided in the ACR Validation and Verification Standard.

The VVB shall keep all documents and records in a secure and retrievable manner for at least 2 years after the end of the relevant project Crediting Period, even if it does not carry out verification throughout the project Crediting Period.

9.F VERIFICATION ACCEPTANCE

ACR will review the verification report and statement and accept them, request corrections and/or clarifications, or reject them. If ACR requests corrections or clarifications, the Project Proponent and verifier shall make all necessary corrections and clarifications and resubmit the verification statement for subsequent review.

If ACR accepts a verification statement, and the project has already completed all other required steps, then ACR will post the validation and verification reports, verification statement, and other public documentation to the ACR website (if applicable), and issue ERTs to the Project Proponent's account.

Projects must be verified without reservation, with Project Proponents having addressed all clarifications and corrections required by the verifier. ACR reserves the right to accept or reject verification from an approved VVB.

9.G ROTATION OF VERIFICATION BODIES

ACR requires that Project Proponents utilize a different VVB at a minimum of every 5 years[25] of reporting or five verifications (including both full and desk reviews), whichever comes first. The first verification conducted by a new VVB must be a full verification.

9.H VALIDATION AND VERIFICATION BODY OVERSIGHT

In addition to the accreditation processes to which all ACR VVB's must adhere, ACR reserves the right to conduct oversight activities during validation and/or verification performance by the VVB's operating under the ACR program. Oversight activities are conducted to ensure an adequate level of quality control and are intended to supplement accreditation body oversight and audit processes. Oversight activities conducted by ACR representatives include the following:

- Review of information and supplementary documentation submitted by VVBs regarding project-specific conflict of interest determinations;
- Review of VVB documentation, such as verification and sampling plans and calculation spreadsheets;
- Review of Project Proponent documentation, such as data sources, quantification methodologies, and calculation spreadsheets or databases;Review of validation and verification reports and verification statements; and
- Project-level audits.

[25] In this context, a year is defined as a 12-month period.

Should ACR select a project for a project-level audit, the VVB must include ACR on communications with the Project Proponent and in substantive meetings with the Project Proponent, and make project-level data and information subject to validation and/or verification available to ACR for review. During a project-level audit, ACR may choose to send, at its own expense, a representative to the validation and/or verification site visit to observe on-site verification activities. At the conclusion of a project-level audit, ACR will communicate its observations in a written report directly to the VVB. The report will document, as applicable, any items of concern noted during validation and/or verification performance, including areas for improvement and non-conformities with ACR validation and verification procedures.

CHAPTER 10: AVOIDING DOUBLE COUNTING WITH OTHER GHG PROGRAMS & REGISTRIES, EMISSION TRADING SYSTEMS, AND NATIONAL OR SECTORAL GHG EMISSIONS REDUCTION TARGETS

In the context of climate change mitigation, double counting refers to situations where a single GHG emission reduction, removal, avoidance, or other mitigation outcome is used more than once to demonstrate achievement of mitigation targets or pledges. Double counting can occur in different ways, including double issuance, double use, and double claiming. ACR has program rules and operational processes, tracking systems, and oversight to mitigate these double counting risks and incorporates by reference the procedures to avoid double counting as detailed in "*Guidelines on Avoiding Double Counting for the Carbon Offsetting and Reduction Scheme for International Aviation*" version 1.0 of June 2019[26] and any future updates to this document in which ACR participates as a workgroup member. ACR will adhere to any future requirements established by the UNFCCC and International Civil Aviation Organization to prevent double counting and to ensure the environmental integrity of emissions reductions.

10.A POLICIES TO PREVENT DOUBLE ISSUANCE AND DOUBLE USE OF OFFSETS

Double issuance occurs when more than one unique unit is issued for the same emissions reduction or removal, within the same program/registry or involving concurrent issuance under more than one program(s)/registry(ies). ACR has rules and procedures in place to mitigate the risk of double issuance, including checks of duplicate registration under other programs and requirements for disclosure of other registrations, as well as for cancelation of the units on one registry prior to re-issuance on another.

[26] https://americancarbonregistry.org/carbon-accounting/guidance-tools-templates/guidelines-for-adc-with-corsia-june-2019.pdf

Double use refers to either 1) an instance in which a single GHG reduction or removal is sold to more than one entity at a given time (also referred to as double selling) due to double issuance or fraudulent sales practices, which may or may not be detectable, or 2) an instance in which an issued unit is used by the same buyer toward more than one target (e.g., under systems that are not linked, do not coordinate, or may have inconsistent rules for reporting and/or retirement). To prevent double use, ACR requires execution of ACR's legal Terms of Use (ToU) Agreement by authorized account representatives, clear proof of ownership upon registration, tracking of ownership of credits within the registry by serial number and account, and an annual attestation of unique, uncontested ownership and legal rights to the emissions reductions as well as that no emissions reductions issued by and registered on ACR have been serialized, registered, retired or otherwise transacted on another registry and/or by another standard nor have they been transferred, retired or otherwise used or disposed of other than as duly recorded on the ACR registry.

10.A.1 Projects Registered on ACR and Other Voluntary or Compliance GHG Programs

ACR allows for offset project registration simultaneously on ACR and other voluntary or compliance GHG programs or registries in only two circumstances: 1) the simultaneous registration is disclosed and approved by both programs/registries, including explicitly through regulation, and 2) offsets issued for the same unique emissions reductions (project boundary and vintage) do not reside concurrently on more than one registry.

To prevent double issuance and double use of offsets for projects registered simultaneously on ACR and another GHG program, 1) offsets representing the same emissions reduction must be publicly canceled from one registry before they can be converted and re-issued on another registry or 2) offsets can be issued to a project by both programs as long as the registration of the project under more than one program is disclosed in writing to the GHG program and the verifier, and the offset represents unique emissions reductions in terms of location (project boundary) and vintage.

10.A.2 Transferred Projects Previously Registered on ACR and Other Voluntary or Compliance GHG Programs or Registries

For projects transferring from another GHG program to ACR, the project must be validated and verified by an ACR-approved VVB to comply with the ACR Standard and relevant methodology. To avoid double issuance and double use of the same GHG reduction or removal, any offsets that had been issued that were not transferred, sold, or retired must be canceled from the other program's registry before conversion and re-issuance by ACR.

For projects transferring from ACR to another GHG program, Project Proponents must cancel from ACR all offsets that have not been transferred, sold, or retired to allow for conversion and re-issuance of offsets by the other GHG program on its registry.

10.B POLICIES TO PREVENT DOUBLE CLAIMING OF EMISSIONS REDUCTIONS

Double claiming occurs when two or more parties claim the same GHG reduction, removal, or other mitigation outcome toward their regional, national, or sector-wide emissions reduction cap, target(s) / pledge(s) / contributions / commitments (collectively “target”).

In the pre-2020 carbon market context, double claiming occurs if emissions reductions that reduce or remove emissions from activities that are part of a binding GHG emissions trading program, or that take place in a jurisdiction or sector in which there is a binding limit/cap established on GHG emissions, are being issued as offsets for use outside of those programs. This would include, for example, emissions reductions in Annex I countries that ratified the Kyoto Protocol, in the EU Emissions Trading System, in the California cap-and-trade program, and in the Regional Greenhouse Gas Initiative. In these instances, offset Project Proponents shall provide evidence that the reductions and removals the project generated have not and will not be used in the emissions trading program or for the purpose of demonstrating compliance with binding limits that are in place in that program or jurisdiction.

If Project Activities take place in such a program or jurisdiction, the Project Proponent shall include in its GHG Project Plan a written statement from the GHG emissions program operator, as well as other documentation in a form acceptable to ACR, that it has canceled from the program or national or regional cap (as applicable) a number of emissions allowances, offsets or other (acceptable) GHG credits equivalent to the reductions and removals generated by the project so that they can no longer be used within the operator’s GHG program. Alternately, the Project Proponent may provide evidence of purchase and cancelation of GHG allowances equivalent to the GHG emissions reductions or removals the project generated related to the program or national cap.

In order to prevent double-counting of GHG emission reductions or removal enhancements for offset projects in non-Annex I countries under the UNFCCC, Project Proponents shall provide documentation that they have notified the relevant project host country Designated National Authority (DNA) of their project registration in the voluntary market, including the project’s expected GHG reductions/removals.

10.B.1 The Paris Agreement and the International Civil Aviation Organization Carbon Offset Reduction Scheme for International Aviation

In the post-2020 carbon market context, in which all signatories to the Paris Agreement have emissions reduction target(s) / pledge(s) / contributions / commitments (collectively "targets") as formulated in the nationally determined contributions (NDCs) and air carriers have an offsetting obligation under the International Civil Aviation Organization Carbon Offset Reduction Scheme for International Aviation (CORSIA), double claiming occurs when two or more Parties claim the same emission reduction to comply with their mitigation targets/pledges/commitments/obligations. Transparent reporting and accounting procedures at both the national and international level will be developed to track emissions reductions transferred to / from other Parties to meet targets. In these instances, as required by the UNFCCC, a corresponding adjustment may be made by the host country of the emissions reduction activity to account for the transfer of the emissions reduction for use by another Party towards its NDC or by airlines towards their CORSIA obligation. The adjustment will be applied, as determined by the UNFCCC, to the host country national GHG inventory or NDC, and will also be reported by the receiving Party.

To mitigate the risk of double claiming in these instances, ACR will require notification by the owner of the emissions reductions of the export of any emissions reductions for these purposes as well as a formal host country letter of assurance and authorization of the use of the emissions reductions by another Party, including for the CORSIA. ACR will report to the project host country's national UNFCCC focal point and the transferee country's UNFCCC focal point the details of any ACR units transferred / retired for use by another Party toward fulfillment of its Paris Agreement targets / pledges / contributions / commitments and/or canceled by/for an airline for use toward its CORSIA obligation.

ACR will post publicly on the registry the national UNFCCC focal point letter of assurance and authorization of transfers / cancelations of emissions reductions towards a mitigation target / obligation. ACR will make public on the registry all retirements / cancelation of units toward a CORSIA offsetting obligation. In addition, ACR will report such information to ICAO and to host countries as required to confirm that the units are included in national emissions reporting to facilitate GHG accounting reconciliation via corresponding adjustments, as determined by the UNFCCC and the CORSIA.

CHAPTER 11: COMPLAINTS AND APPEALS PROCEDURE

11.A COMPLAINTS PROCEDURE

When a Project Proponent or ACR stakeholder objects to a decision made by ACR representatives or the application of the ACR program requirements, the following confidential complaint procedure shall be followed:

1. Project Proponent or ACR stakeholder sends a written complaint via email to ACR@winrock.org. The complaint must detail the following:
   - Description of the complaint with specific reference to ACR Standard and/or ACR Methodology requirements, as applicable;
   - Supporting documentation provided for consideration by ACR in the complaint resolution process; and
   - Complainant name, contact details, and organization.
2. ACR Senior Management shall assign an ACR representative to research and further investigate the complaint. The representative assigned to handle the complaint shall not have been involved with the issue that is the subject of the formal complaint.
3. ACR Senior Management will provide a written response, via email, to the complainant detailing ACR's decision on the matter.

11.B APPEALS PROCEDURE

In the event that a complaint remains unresolved after the conclusion of the complaints procedure, an ACR Project Proponent or stakeholder may appeal any such decision or outcome reached. The following confidential appeals procedure shall be followed:

1. Project Proponent or ACR stakeholder sends a written appeal via email to ACR@winrock.org. The appeal must detail the following:
   - Description of the appeal, with specific reference to ACR Standard and/or ACR Methodology requirements, as applicable;
   - Supporting documentation provided for consideration in the appeal process, including previous communication on the complaint and all relevant details of the previously implemented complaint procedure; and
   - Appellant name, contact details, and organization.
2. ACR Senior Management shall forward the appeal to the appropriate Winrock Senior Director, who will convene a committee of representatives to review and discuss the matter. The committee will include a member of the Winrock Board of Directors, a

member of the Winrock Senior Management team, and an ACR staff member unrelated to the complaint, all of whom will have equal votes. The committee may also include a technical and/or subject matter expert or experts as necessary, who will not be able to vote. The committee members selected will depend on the subject matter and nature of the appeal.

3. The decision reached by the committee shall be communicated, via written response, to the ACR Project Proponent or stakeholder. Any decision reached by the committee shall be final.

DEFINITIONS

Additionality	ACR's additionality requirements are intended to ensure that project offsets are in addition to reductions and/or removals that would have occurred in the absence of the Project Activity and without carbon market incentives. A Project Proponent must demonstrate that the GHG emission reductions and removals associated with an offset project are above and beyond the "business as usual" scenario. ACR requires that every project either pass an approved performance standard and a regulatory additionality test, or pass a three-pronged test to demonstrate that the Project Activity is beyond regulatory requirements, beyond common practice, and faces at least one of three implementation barriers (institutional, financial, or technical).
Afforestation/ Reforestation	Activities to increase carbon stocks by establishing, increasing, and restoring vegetative cover through the planting, sowing, or human-assisted natural regeneration of woody vegetation. These activities must target the eventual establishment of "forest" per the applicable definition. In general, the term "afforestation" is applied to activities to establish forest on lands that have been in another land use for some relatively long period, and "reforestation" is applied to activities to reestablish forest on lands that were relatively recently in forest cover. ACR does not make a specific distinction between afforestation and reforestation, because both are eligible. Project Proponents shall document that afforestation/reforestation project lands were not cleared of trees during the 10 years preceding the project Start Date in order to implement an afforestation/reforestation project. This exclusion does not apply to natural disturbances or to removal of non-tree vegetation (e.g., heavy brush) to prepare the site for planting. Project lands that already meet the applicable "forest" definition due to the percentage tree cover or other factors, and on which a Project Proponent wishes to implement activities to increase carbon stocks by increasing and restoring vegetative cover through the planting, sowing, or human-assisted natural regeneration of woody vegetation, qualify under the Improved Forest Management (IFM) category.
Aggregate	The grouping of multiple project instances, fields, producers, or facilities into a single project registered on ACR. An Aggregate must be coordinated by a Project Proponent (public or private entity) serving as the aggregator. The GHG Project Plan will define the overall project boundary and baseline conditions encompassing all project instances, fields, producers, or facilities. An Aggregate will have a single Start Date and Crediting Period.
Agriculture, Forestry, and Other Land Use (AFOLU)	A broad category of ACR-eligible project activities that reduce GHG emissions and/or enhance GHG removals through changes in agriculture, forestry, and land-use practices.

Agricultural Land	Any ecosystem modified or created specifically to grow or raise biological products for human consumption or use. This includes cropland, pasture, rangeland, orchards, groves, vineyards, nurseries, ornamental horticultural areas, and confined feeding areas. It is generally synonymous with farmland.
American Carbon Registry® (ACR)	A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has two decades of experience in the development of environmentally rigorous, science-based offset methodologies, as well as operational experience in the oversight of offset project verification, registration, offset issuance, and retirement reporting through its online registry system.
ACR-Approved Methodology	GHG quantification, monitoring, reporting, and verification published by ACR after public consultation and scientific peer review, and methodologies approved for use by the CDM Executive Board, provided they are approved for use by ACR.
Annual Attestation Statement	The statement that a Project Proponent provides annually to ACR relating to the continuance, ownership, and community and environmental impacts of a project. The Attestation is required to continue crediting.
Avoided Conversion of Forest	Activities that prevent the conversion of forests to development, agriculture or other land uses.
Avoided Conversion of Non-Forest	Activities that prevent the conversion of non-forest native lands to anthropogenically productive uses (e.g., cropland, settlement, or development). Eligible project activities include avoided conversion of grasslands and shrublands to crop production.
Baseline Scenario	A counterfactual scenario that forecasts the likely stream of emissions or removals to occur if the Project Proponent does not implement the project (i.e., the “business as usual” case). It also reflects the sum of the changes in carbon stocks (and, where significant, nitrous oxide and methane emissions) in the carbon pools within the project boundary that would occur in the absence of the Project Activity.
Buffer Contribution	The number of offsets contributed to the Buffer Pool for AFOLU projects with a risk of reversal.
Buffer Pool	An account managed by ACR as a reversal risk mitigation mechanism for AFOLU projects into which Project Proponents contribute a determined quantify of ERTs to replace unforeseen losses in carbon stocks. The Buffer Contribution is a percentage of the project’s reported offsets, the Minimum Buffer Percentage, determined through a project-specific assessment of the

	risk of reversal. The buffer contribution may be made in ERTs of any type and vintage.
Cancel or Cancelation	The permanent removal of an offset credit from the Registry so that it cannot be transferred, transacted, retired or applied towards any emissions reduction targets as an ACR offset credit unit. The exception to this is for airplane operators who cancel units to surrender them towards their CORSIA compliance obligations. If the offset credit has been canceled so that the equivalent can be reissued on another offset program, ACR no longer tracks the credit ownership and permanence (if applicable).
Carbon Dioxide-Equivalent (CO_2e)	A metric to compare GHGs based on their global warming potential (GWP) relative to CO_2 over the same timeframe. The Intergovernmental Panel on Climate Change publishes GWP values for converting all GHGs to a CO_2e basis.
Carbon Offset	A reduction, removal, or avoidance of GHG emissions that is used to compensate for GHG emissions that occur elsewhere. In a regulated market, offsets are GHG reductions from projects undertaken outside the coverage of a mandatory emissions reduction system for which the ownership of verifiable GHG emission reductions can be transferred and used by a regulated source to meet its emission reduction obligations."[27] The ACR registers both voluntary market and compliance-eligible offsets. Also referred to as a verified emission reduction (VER), a carbon credit, or offset credit.
Carbon Pool	A reservoir of carbon that has the potential to accumulate or lose carbon over time. Common fores t carbon pools are aboveground biomass, belowground biomass, litter, dead wood, soil organic carbon (SOC), and wood products.
Carbon Stocks	The measured, estimated or modeled quantity of carbon held in a particular carbon pool. Quantifying GHG emissions and removals for terrestrial carbon offset projects involves estimating, for the baseline vs. project scenario, changes over time in carbon stocks in relevant pools.
Cohort	A new group of Project Participants, meeting all eligibility, project boundary, baseline, and additionality criteria of an already established Programmatic Development Approach (PDA).
Clean Development Mechanism (CDM)	A mechanism that allows GHG emission reduction and removal projects in non-Annex 1 parties to the UNFCCC to earn certified emission reduction (CER) credits, each equivalent to one metric ton of CO_2, which can be sold and used by Annex 1 countries to a meet a part of their emission reduction targets under the Kyoto Protocol. The CDM is intended to stimulate

[27] Adapted from Pew Center on Global Climate Change. Climate Change 101: Cap and Trade. http://www.pewclimate.org/docUploads/Cap&Trade.pdf.

	sustainable development and emission reductions while giving industrialized countries flexibility in how they meet their emission reduction targets.[28]
Commercially Sensitive Information	Trade secrets, financial, commercial, scientific, technical, or other information whose disclosure could result in a material financial loss or gain, prejudice the outcome of contractual or other negotiations, or otherwise damage or enrich the person or entity to which the information relates.
Community	All groups of people who live within or adjacent to a project area, including indigenous peoples, mobile peoples, and other local communities, as well as any groups that regularly visit the area and derive income, livelihood, or cultural values from it. This may include one or more groups that possess characteristics of a community, such as shared history, shared culture, shared livelihood systems, shared relationships with one or more natural resources (e.g., forests, water, rangeland, wildlife), and shared customary institutions and rules governing the use of resources.[29]
Community and Environmental Impacts	The effects, positive and negative, that a Project Activity may have on the socioeconomic well-being of affected communities or environmental quality in the project area. ACR requires that the Project Activity provide net benefits to affected communities and the environment, and that negative impacts be mitigated or compensated and monitored throughout the project.
Crediting Period	The finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. The baseline must be re-evaluated to renew the Crediting Period. ACR sector standards and methodologies specify the Crediting Period for particular project types.
Cropping Cycle	The period between the first day after harvest of the last crop in a field and the last day of harvest of the current crop. A single cropping cycle does not have to be 12 months, and multiple cropping cycles may occur within a cultivation year.
Cultivation Year	The annual cycle of activities related to the growth and harvest of crops within an approximate 12-month period. A single cultivation year may contain a single cropping cycle or several cropping cycles.
De Minimis	So minor as to merit disregard. ACR sets a de minimis threshold of 3% of the final calculation of emission reductions or removals. For the purpose of completeness, any decreases in carbon pools and/or increases in GHG emission sources that exceed the de minimis threshold must be included. Any exclusions using the de minimis principle shall be justified using fully

[28] http://cdm.unfccc.int/about/index.html.

[29] Climate, Community, and Biodiversity Standards – Project Design Standards. Second Edition (2008). Climate, Community & Biodiversity Alliance.

	documented ex ante calculations, and within the specifications of the chosen methodology.
Do no harm	Offset projects must be in compliance with applicable local, national, and international laws and regulations.
Double Counting	In the context of climate change mitigation, situations where a single GHG emission reduction, removal, avoidance, or other mitigation outcome is used more than once to demonstrate achievement of mitigation targets or pledges. Double counting can occur in different ways, including double issuance, double use, and double claiming.
Double Claiming	Whereby two or more parties claim the same GHG reduction, removal, or other mitigation outcome toward their national or sector-wide emissions reduction cap or target (e.g., mitigation targets/pledges under the Paris Agreement as formulated in the NDCs and/or air carriers offsetting obligation under the CORSIA). Transparent accounting and reporting procedures at both the national and international level must be in place to track emissions reductions transferred to other Parties toward meeting their targets. In these instances, a corresponding adjustment should be made by the host country, adding the emissions back to its national GHG inventory (or NDC), as well as by the receiving party.
Double Issuance	Whereby more than one unique unit is issued for the same emissions reduction or removal, within the same program/registry or involving concurrent issuance under more than one program(s)/registry(ies). This can lead to double use/selling and double claiming, in that more tons are being created and supplied than were actually mitigated. The risk of double issuance can be avoided by having preventative program rules and oversight processes in place, such as cancelation of units by one program prior to re-issuance by another.
Double Use	When a single GHG reduction or removal is sold to more than one entity at a given time, or when an issued unit is used by the same buyer toward more than one target (e.g., under systems that do not “talk” to each other or may have inconsistent rules for reporting and/or retirement). Double use can be avoided by having operational processes, program rules, tracking systems, and oversight processes in place. Also referred to as double selling due to, for example, double issuance (registry/program/verification issue) or fraudulent sales practices, which may or may not be detectable by registry/program/ verifier.
Emission Reduction Ton (ERT)	The ACR unit of exchange for tradable, project-based carbon offsets. ERTs refer to both emission reductions and enhancements in sequestration. ACR issues one ERT for each metric ton of CO_2e emission reductions or removals verified against an ACR Standard and methodology.

Emission Factor	A coefficient that relates an activity datum to the quantity of GHG emissions released to the atmosphere. Emission factors are often based on a sample of measured emissions data that are averaged to develop a representative rate of GHG emissions for a given activity level under a given set of operating conditions.
Farm	The entire operations, which may include multiple fields or parcels of land, and is under the management of a single owner or entity.
Field	A contiguous tract of land with a homogenous management strategy and a common owner separated by permanent boundaries such as fences, waterways, woodlands, or other similar features.
Forest	Forest projects shall use a nationally approved "forest" definition for the country where the activity occurs. For projects in the United States, Project Proponents shall use the U.S. definition in Appendix A, which is based on the U.S. Forest Service Forest Inventory & Analysis Program definition. For projects outside of the United States, Project Proponents may use the Kyoto Protocol definition in Appendix A, with the relevant Designated National Authority (DNA) selections for minimum land area, crown cover, and tree height. If the project is in a country that no longer has a designated DNA or whose DNA has not made these selections, the Project Proponent may propose another nationally approved forest definition. The definition of forest shall apply in each eligible forest project category. For example, afforestation/ reforestation activities must target the eventual establishment of a forest; IFM activities must be implemented in a forest remaining as forest; and Avoided Conversion activities must be implemented in a forest and prevent its conversion to non-forest or its degradation remaining forest.
Geologic Sequestration	The process of capturing carbon dioxide from a stationary source and injecting it deep underground through a well, with or without enhanced oil recovery. Also called carbon capture and storage.
Greenhouse Gas (GHG)	Any gaseous compound that absorbs infrared radiation in the atmosphere and contributes to the warming of the atmosphere. The primary GHGs regulated under the Kyoto Protocol are carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), HFCs, perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The IPCC lists and periodically updates GHGs in its assessment reports. ACR's scope includes all GHGs (including ODS) listed in the IPCC Fourth Assessment Report, Working Group 1, Chapter 2, Table 2.14.[30]
GHG Emission Reductions and Removals	A GHG emission reduction is the measured decrease of GHG emissions over a specified period relative to an approved baseline. A GHG removal is the mass of GHGs removed from the atmosphere over a specified period relative to an approved baseline.

[30] See http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

GHG Emission System/Trading Program	A voluntary or regulated program that allows for trading in project-based GHG emission reductions or removals, government-issued credits, and/or allowances.
GHG Project Plan	A document that describes the Project Activity, satisfies eligibility requirements, identifies sources and sinks of GHG emissions, establishes project boundaries, describes the baseline scenario, defines how GHG quantification will be done and what methodologies, assumptions, and data will be used, and provides details on the project's monitoring, reporting, and verification procedures. ACR requires every project to submit GHG Project Plan using an ACR-approved methodology.
Global Warming Potential (GWP)	A relative scale translating the global warming impact of any GHG into its CO_2e over the same timeframe. The IPCC periodically updates the list of GHGs and their GWP factors, based on the most recent science. ACR requires Project Proponents to calculate GHG reductions and removals based on the 100-year GWPs in the IPCC Fourth Assessment Report, Working Group 1, Chapter 2, Table 2.14.
Grassland and Shrubland	A land-use category on which the plant cover is composed principally of grasses, grass-like plants (e.g., sedges and rushes), forbs, or shrubs. Savannas, some wetlands, deserts, and tundra are considered grassland; they are often suitable for grazing and browsing, and include pastures and native rangelands. Practices such as clearing, burning, chaining, and/or chemicals may be applied to maintain the grass vegetation. Woody plant communities of low forbs and shrubs (e.g., mesquite, chaparral, mountain shrub, and pinyon-juniper) are also classified as grassland and shrubland if they do not meet the criteria for forest land. Grassland includes land managed with agroforestry practices such as silvopasture and windbreaks, assuming the stand or woodlot does not meet the criteria for forest land.
Implementation Date	The site-specific date corresponding to the start of project activities (as they are defined by the relevant methodology) on a single site within a project implementing an Aggregate or Programmatic Design Approach.
Improved Forest Management (IFM)	Activities to reduce GHG emissions and/or enhance GHG removals, implemented on lands designated, sanctioned, or approved for forest management (e.g., production of sawtimber, pulpwood, and fuelwood). Eligible IFM project activities include conversion from conventional logging to reduced-impact logging; conversion of managed forests to protected forests ("stop logging"); extending rotation lengths in managed forest; conversion of low-productive forests to high-productive forests; increasing forest productivity by thinning diseased or suppressed trees; managing competing brush and short-lived forest species; increasing the stocking of trees on understocked areas (including lands not historically managed as forest but meeting the applicable "forest" definition due to percent tree cover or other factors);

	increasing carbon stocks in harvested wood products; improving harvest or production efficiency; and shifting from shorter- to longer-term wood products.
Indirect GHG Emissions	GHG emissions caused by a Project Proponent's activities but that are not directly released into the atmosphere from sources owned or controlled by the Project Proponent. Indirect emissions can occur upstream or downstream from activities directly controlled by the Project Proponent.
Intentional Reversal	The decrease of average carbon stocks within a project area below levels associated with previously issued ERTs as a result of intentional, willful activity (e.g., harvesting, forest conversion) on the part of the Project Proponent or project owner(s). When carbon stocks decline in this way (i.e., negative stocks, relative to previous reporting), it is assumed that the carbon is released back into the atmosphere. Willful withdrawal of a parcel or parcels from a PDA or aggregated project such that monitoring and verification will no longer be conducted for the minimum project term is automatically considered an intentional reversal and must be compensated per the provisions in the Project Proponent's Risk Mitigation Agreement with ACR.
Intergovernmental Panel on Climate Change (IPCC)	The IPCC is "the leading body for the assessment of climate change, established by the United Nations Environment Programme (UNEP) and the World Meteorological Organization (WMO) to provide the world with a clear scientific view on the current state of climate change and its potential environmental and socioeconomic consequences."[31]
Leakage	A decrease in sequestration or increase in emissions outside project boundaries resulting from project implementation. Leakage may be caused by shifting of the activities of people present in the project area or by market effects whereby emission reductions are countered by emissions created by shifts in supply of and demand for the products and services affected by the project.
Listing	The process by which a Project Proponent submits a draft GHG Project Plan to ACR for review, the successful outcome of which results in the project being approved for listing as a project on the ACR platform. ACR's review and subsequent approval of a project listing is not a project certification, nor does it take the place of a successful validation and verification.
Methodology	A systematic approach that establishes requirements for a Project Proponent to develop the project baseline scenario(s) and to quantify, monitor, report, and verify emissions reductions or removals by following scientific good practice. Good practice entails that a methodology be conservative, transparent, and thorough.

[31] http://www.ipcc.ch/organization/organization.htm.

Methodology Deviations and Revisions	A project-specific change to an existing approved methodology due to a change in the conditions, circumstances, or nature of a project. A deviation may be accepted for a specific project but does not result in an approved modification to the methodology. A methodology revision is a fundamental change in an existing approved methodology due to a change in conditions, circumstances, or general developments in knowledge. ACR approval of methodology deviations and modifications is determined by the relevant ACR Technical Committee. Approval of revisions requires public consultation and peer review.
Methodological Tools	An approved component of a methodology (e.g., a stand-alone methodological module to perform a specific task) or a calculation tool (e.g., spreadsheets or software that perform calculation tasks) that a Project Proponent uses to quantify net GHG reductions/removals or meet other ACR requirements.
Minimum Buffer Percentage	An overall reversal risk rating for an AFOLU project based on the ACR Tool for Risk Analysis and Buffer Determination, which translates into the number of offsets that will be deposited in the ACR Buffer Pool at each issuance to mitigate the risk of reversals.
Minimum Project Term	The minimum period for which a Project Proponent commits to project continuance, monitoring, and verification.
Monitoring	Continuous or periodic direct measurements and/or indirect assessment of GHG emissions, reductions, or other GHG data that is typically specified in the ACR-approved methodology.
Native vs. Non-native Vegetation	Native vegetation is a part of the balance of nature that has developed over hundreds or thousands of years in a particular region or ecosystem. Non-native vegetation does not need human help to reproduce and maintain itself over time in an area where it is not native.
Naturalized Plants	Refers to non-native vegetation that does not need human help to reproduce and maintain itself over time in an area where it is not native. Even though their offspring reproduce and spread naturally (i.e., without human help), naturalized plants do not become native members of the local plant community.
Net Emissions Reductions	GHG emission reductions or removals created by a Project Activity, minus the baseline scenario and any deductions for uncertainty and leakage.
Ozone-Depleting Substances (ODS)	Controlled substances under Annexes A, B, C, and E of the Montreal Protocol,[32] many of which are also potent GHGs. The Montreal Protocol controls the consumption, production, and international trade of ODS, but not

[32] See http://ozone.unep.org/Publications/MP_Handbook.

	emissions; therefore, the destruction of ODS in existing facilities and equipment worldwide has the potential to prevent significant GHG emissions.
Pasture	Grassland that has been seeded, usually to introduced species, and intensively managed for livestock using agronomy practices and control of livestock.
Permanence	In GHG accounting, a reference to the perpetual nature of GHG removal enhancements and the risk that a project's atmospheric benefit will not be permanent. GHG removals may not be permanent if a project has exposure to risk factors such as intentional or unintentional events (e.g., fire, flood, insect infestation) that results in the emissions into the atmosphere of stored or sequestered CO_2e for which offset credits were issued (i.e., a reversal).
Permanence Risk Analysis	To account for and mitigate against the risk of reversal in some AFOLU projects, ACR requires Project Proponents to conduct a risk analysis to determine the number of offsets that must be deposited in the ACR Buffer Pool. The risk analysis evaluates several types of risk—project, economic, regulatory, and social and environmental/natural disturbance—and must be conducted using the ACR-approved tool.
Programmatic Development Approach (PDA)	A project in which successive cohorts of sites are added incrementally to a project over time. A PDA must be coordinated by a Project Proponent (public or private entity) that must use an approved baseline and monitoring methodology that defines the appropriate boundary, avoids double counting, accounts for leakage, and ensures that the emission reductions are real, measurable, verifiable, and additional to any that would occur in the absence of the project.[33]
Project Boundaries	A GHG project's physical boundary or implementation area, the GHG sources, sinks and reservoirs (or pools) considered, and the project duration.
Project Proponent	An individual or entity that undertakes, develops, and/or owns a project. This may include the project investor, designer, and/or owner of the lands/facilities on which project activities are conducted. The Project Proponent and landowner/facility owner may be different entities. The Project Proponent is the ACR account holder.
Rangeland	A land use category generally synonymous with grazed grassland. Rangelands support native vegetation and include areas that have been seeded to introduced species but are managed as native range.

[33] Adapted from Clean Development Mechanism Rulebook at http://cdmrulebook.org/452.

Registration	Projects are considered registered and eligible for ERT issuance into a Project Proponent's account upon acceptance of the validation report and a positive verification opinion.
Reporting Period	The period of time covering a GHG assertion that is submitted for a single verification and subsequent request for ERT issuance.
Sustainable Biomass	Biomass which meets one of the following conditions: a) The biomass is a biomass residue and the use of that biomass residue in an ACR project activity does not involve a decrease of carbon pools, in particular dead wood, litter or soil organic carbon, on the land areas from which the biomass residues originate; (b) The biomass is the non-fossil fraction of industrial or municipal waste. Such sources can include: Agricultural residues, animal wastes, forestry residues, wood wastes, industrial wastes such as black liquor and food processing.
Retire or Retirement	The permanent removal of an offset credit from circulation as a transactable unit so that it represents a permanent reduction or removal of CO_2e from the atmosphere. A retired credit may be applied toward the emissions reduction target of the ACR account holder that retired the credit, or on behalf of a third party.
Reversal	An intentional or unintentional event that results in the emissions into the atmosphere of stored or sequestered CO_2e for which carbon offsets (ERTs) were issued.
Site	A physical location at which GHG emissions are generated and/or GHG emissions reductions are achieved. Project sites may consist of forest, fields, parcels of land, or industrial facilities located within the project boundary.
Standard	A standard is an established norm or requirement in a formal document that establishes uniform engineering or technical criteria, methods, processes, and practices. Standards may provide general guidance across all project types, such as this document, or be sector-specific. ACR registers only projects that meet the ACR Standard.
Start Date	For non-AFOLU projects, the date on which the project began to reduce GHG emissions against its baseline. For AFOLU projects, the date on which the Project Proponent began the activity on project lands, with more specific guidance in the relevant ACR sector-specific requirements.
Terrestrial Sequestration	The process of increasing the carbon stock of terrestrial carbon pools by changing the management of forests, rangelands, agricultural lands, and wetlands, resulting in increased removals of CO_2 from the atmosphere and sequestration of carbon through biological processes.

Unintentional Reversal	The decrease of average carbon stocks within a project area below levels associated with previously issued ERTs as a result of natural disturbances. Examples include fire, disease, and insect infestations.
Validation	The systematic, independent, and documented process for the evaluation of a GHG Project Plan against applicable requirements of the ACR Standard, sector standard, and approved methodology.
Validation/ Verification Body (VVB)	A competent and independent person, persons, or firm responsible for performing the validation and/or verification process. A VVB must be ACR-approved to conduct verification.
Verification	The systematic, independent, and documented assessment by a qualified and impartial third party of the GHG assertion for a specific reporting period. The verification process is intended to assess the degree to which a project complies with ACR-approved methodologies, tools, eligibility criteria, requirements, and specifications, and has correctly quantified net GHG reductions or removals. Verification must be conducted by an independent third-party verifier.
Verification Statement	A statement issued by a verification body that provides assurance, through examination of objective evidence by a competent and independent third party, that a GHG assertion is in conformity with applicable requirements.
Wetlands	Areas inundated or saturated by surface or ground water at a frequency and duration sufficient to support (and that under normal circumstances do support) a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

APPENDIX A: ACR REQUIREMENTS FOR AGRICULTURE, FOREST, AND OTHER LAND USE-BASED CARBON PROJECTS

PURPOSE

This annex details ACR's overarching requirements for the quantification, monitoring, and reporting, verification, registration, and issuance of carbon emissions reductions and removals from AFOLU project activities. All AFOLU projects must also meet all relevant requirements of the main body of this ACR Standard.

The ACR Requirements for AFOLU-Based Carbon Projects supersedes the ACR Forest Carbon Project Standard version 2.1 and includes updates, clarifications for consistency, and removal of redundancies with the ACR Standard and approved methodologies. Details around non-forest project types have also been added to include agriculture and other land use-specific requirements. All essential requirements remain unchanged.

APPLICABILITY

The ACR Requirements for AFOLU-Based Carbon Projects cover the project types specified in Section A.1 below. Other eligible AFOLU carbon project types may be added in the future.

A.1 ELIGIBLE PROJECT TYPES

A.1.1 Eligible Project Types

The following broad categories of AFOLU project types are eligible for registration on ACR. Within each category, the GHG Project Plan will outline specific activities undertaken to reduce GHG emissions and/or enhance removals.

- **IMPROVED FOREST MANAGEMENT (IFM)** Activities to reduce GHG emissions and/or enhance GHG removals, implemented on lands designated, sanctioned, or approved for

forest management (e.g., production of sawtimber, pulpwood, and fuelwood). Eligible IFM project activities include conversion from conventional logging to reduced impact logging; conversion of managed forests to protected forests ("stop logging"); extending rotation lengths in managed forest; conversion of low-productive forests to high-productive forests; increasing forest productivity by thinning diseased or suppressed trees; managing competing brush and short-lived forest species; increasing the stocking of trees on understocked areas (including lands not historically managed as forest but meeting the applicable "forest" definition due to percent tree cover or other factors); increasing carbon stocks in harvested wood products; improving harvest or production efficiency; and shifting from shorter- to longer-term wood products and activities to avoid emissions from wildfire by improving fuels and fire management.

- **AFFORESTATION/REFORESTATION (AR)** Activities to increase carbon stocks by establishing, increasing, and restoring vegetative cover through the planting, sowing, or human-assisted natural regeneration of woody vegetation. AR activities must target the eventual establishment of "forest" per the applicable definition. In general, the term "afforestation" is applied to activities to establish forest on lands that have been in another land use for some relatively long period, and "reforestation" is applied to activities to reestablish forest on lands that were in forest cover relatively recently. ACR does not make a specific distinction between afforestation and reforestation, because both are eligible.

  Project Proponents shall document that afforestation/reforestation project lands were not cleared of trees during the 10 years preceding the project Start Date in order to implement an afforestation/reforestation project. This exclusion does not apply to natural disturbances or to removal of non-tree vegetation (e.g., heavy brush) to prepare the site for planting. Project lands that already meet the applicable "forest" definition due to the percentage tree cover or other factors, and on which a Project Proponent wishes to implement activities to increase carbon stocks by increasing and restoring vegetative cover through the planting, sowing, or human-assisted natural regeneration of woody vegetation, qualify under the Improved Forest Management (IFM) category.
- **AVOIDED CONVERSION OF FOREST (AC-F)** The reduction in GHG emissions from the avoided conversion of forest to non-forest use (e.g., to cropland, grassland, settlement, or development) or avoided degradation of forests remaining as forests.
- **AGRICULTURE-SOIL CARBON ENHANCEMENT** Activities that increase soil carbon sequestration on agricultural land through the application of soil amendments, the improvement of primary productivity, and/or less disruptive management practices. Eligible project activities include compost addition to grasslands and changes in tillage practices.
- **AGRICULTURE-AVOIDED EMISSIONS** Activities that reduce emissions of GHGs by improving efficiency of inputs or the application of a lower GHG practice practice/technology. Eligible project activities include changes to fertilizer rate and application, and changes in rice management systems.
- **WETLAND RESTORATION OR REVEGETATION** Activities that increase carbon sequestration and/or prevent soil oxidation on degraded wetlands. Eligible project activities include tidal wetland creation, deltaic wetland creation, and rewetting previously drained wetlands, including pocosins. Quantification frameworks and baseline definitions need to be developed for each location where this project type is applied due to unique, location-specific wetland dynamics, pressures, and restoration techniques.

- **AVOIDED CONVERSION OF NON-FOREST** The reduction in GHG emissions from the avoided conversion of lands with non-forest, native vegetation to anthropogenically productive uses (e.g., to cropland, settlement, or development). Eligible project activities include avoided conversion of grasslands and shrublands to crop production.

Project Proponents uncertain about eligibility of a planned activity may consult with ACR.

A.1.2 AFOLU Projects with a Biomass Energy Component

AFOLU carbon activities may include a biomass energy component if they provide biomass fuel for Scope One, direct electricity generation, heating, or transportation fuels. Such projects occupy a unique GHG accounting niche with potential impacts on GHG emissions and removals in terrestrial ecosystems, as well as the ability to displace GHG emissions from fossil fuels. Projects that combine an eligible forest carbon Project Activity with biomass production shall account for changes in GHG reductions and removals in forest carbon pools using the requirements outlined in this document and appropriate AFOLU methodologies. Displacement of fossil fuel GHG emissions, if eligible, shall be accounted for by using appropriate energy sector methodologies and tools. Please refer to Chapter 1, Section E, of the ACR Standard for requirements related to renewable energy.

A.2 ACCOUNTING PRINCIPLES

A.2.1 Exclusion of Pools in Accounting

Project Proponents should refer to Chapter 2 of the ACR Standard for general accounting and data quality principles. Additional guidance is provided here for forest AFOLU projects. In general, the basis for ACR's accounting principles is ISO 14064 Part 2:2006, Specification, with guidance at the project level for quantification, monitoring, and reporting of GHG emission reductions or removal enhancements.

Project Proponents shall apply the guidance in ISO 14064-2:2006 and consider all relevant information that may affect the accounting and quantification of GHG reductions/removals, including estimating and accounting for any decreases in carbon pools, avoided emissions, and/or increases in GHG emission sources.

ACR methodologies dictate which GHG sources, sinks and pools must be accounted for in the GHG boundary for each project. However, the Project Proponent may elect to exclude from accounting a GHG source, sink, or pool if any of the following is demonstrated:

- The source, sink, or pool is a priori optional per the guidance below or has been explicitly excluded from the project boundary in the applied methodology.
- The source, sink, or pool is demonstrated to be de minimis per the ACR definition. A pool or source not initially considered de minimis in ex ante calculations, but found to be de minimis

in monitoring, may be omitted from subsequent monitoring and verification if the Project Proponent presents evidence that the pool or source is likely to remain indefinitely below the de minimis threshold (i.e., that the monitoring activities in which an individual pool or source was de minimis was not merely a temporary condition).

- All combined sources, sinks, and pools thus excluded must represent less than 3% of the ex-ante calculation of emission reductions/removal enhancements.

Sources, sinks, and pools that could be excluded may still be accounted; but any source, sink, or pool selected for accounting in the baseline scenario must also be accounted in the project scenario.

The following pools and sources are considered insignificant a priori for AFOLU carbon projects.

Emissions sources:

- Fertilizer application in forest projects.
- Removal of herbaceous vegetation in forest projects.
- Transportation emissions from vehicles used in project visits, monitoring, verification, etc. This does not include emissions of harvest, processing, or transport equipment, which may be insignificant but are not insignificant a priori; the Project Proponent shall justify exclusion of such emissions.
- Collection of wood from non-renewable sources to be used for fencing of the project area.
- Nitrous oxide (N_2O) emissions from decomposition of litter and fine roots from nitrogen-fixing trees.

Carbon pools:

- Litter

A.3 ELIGIBILITY REQUIREMENTS

A.3.1 AFOLU Land Classification

1. Forest projects shall use a nationally approved “forest” definition for the country where the activity occurs. For projects in the United States, Project Proponents shall use the U.S. definition below, which is based on the U.S. Forest Service Forest Inventory & Analysis Program definition. For projects outside of the United States, Project Proponents may use the Kyoto Protocol definition below, with the relevant Designated National Authority (DNA) selections for minimum land area, crown cover, and tree height. If the project is in a country that no longer has a designated DNA or whose DNA has not made these selections, the Project Proponent may propose another nationally approved forest definition.

Forest (for projects in U.S.; based on U.S. Forest Service Forest Inventory & Analysis Program definition)[34]

Land with at least 10% cover (or equivalent stocking) by live trees of any size, including land that formerly had such tree cover and that will be naturally or artificially regenerated. To qualify, the area must be at least 1 acre in size. Forest land includes transition zones, such as areas between forest and non-forest lands that have at least 10% cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands.

Forest (for projects in Kyoto Protocol signatory countries)

The Kyoto Protocol defines forest as follows but allows each country's DNA to define minimum land area, crown cover, and tree height within the bracketed ranges: A minimum area of land of (0.05–1.0 hectares) with a minimum tree crown cover (or equivalent stocking level) of (10–30%) with trees, and with the potential to reach a minimum height of (2–5 meters) at maturity in situ. A forest may consist either of closed forest formations, where trees of various heights and undergrowth cover a large portion of the ground, or open forest. The definition includes young natural stands and all plantations that have yet to reach a crown density of (10–30%) or tree height of (2–5 meters), as well as areas that usually form part of the forest area but that are temporarily unstocked because of human intervention (e.g., harvesting) or natural causes, but likely will revert to forest.[35]

The definition of forest shall apply in each eligible forest project category. For example, afforestation/ reforestation activities must target the eventual establishment of a forest; IFM activities must be implemented in a forest remaining as forest; and Avoided Conversion activities must be implemented in a forest and prevent its conversion to non-forest or its degradation remaining forest.

2. Wetlands are areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support (and that under normal circumstances do support) a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas. Methodologies specific to different types of wetlands must define the specific regional geographic applicability.
3. Agricultural Land is defined as any ecosystem modified or created specifically to grow or raise biological products for human consumption or use. This includes cropland, pasture, rangeland, orchards, groves, vineyards, nurseries, ornamental horticultural areas, and confined feeding areas. It is generally synonymous with farmland.

[34] See http://fia.fs.fed.us/library/database-documentation/current/ver4/draft%20FIADB_user%20manual_v4-0_p2_12_22_2009.pdf at page 51. ACR does not exclude urban forestry activities, or forested areas less than 120 feet wide, from potentially meeting the definition of forest.

[35] DNA selections for minimum land area, crown cover, and tree height are at http://cdm.unfccc.int/DNA/allCountriesARInfos.html. If the project is in a country that has not yet designated a DNA or whose DNA has not yet made selections, the Proponent may propose another nationally approved forest definition.

4. Grassland and shrubland is a land-use category on which the plant cover is composed principally of grasses, grass-like plants (e.g., sedges and rushes), forbs, or shrubs. Savannas, some wetlands, deserts, and tundra are considered grassland. They are often suitable for grazing and browsing, and include both pastures and native rangelands. Practices such as clearing, burning, chaining, and/or chemicals may be applied to maintain the grass vegetation. Woody plant communities of low forbs and shrubs (e.g., mesquite, chaparral, mountain shrub, and pinyon-juniper) are also classified as grassland and shrubland if they do not meet the criteria for forest land. Grassland includes land managed with agroforestry practices such as silvopasture and windbreaks, assuming the stand or woodlot does not meet the criteria for forest land.[36]

A.3.2 Eligible Land Ownership Types

ACR accepts projects on all land ownership types—private, public (municipal, county, state, federal, or other), and tribal—provided the Project Proponent demonstrates that the land is eligible, documents clear land title and offsets title, the offsets contract is enforceable, and the Project Activity is additional and meets all other requirements of the ACR Standard. Projects on public lands, like any other project, shall demonstrate that the activity is not required by regulations and meets other additionality criteria. Agriculture and land use projects that generate ERTs with no risk of reversal need not demonstrate land title.

A.3.3 Eligibility Criteria

Table 4 details unique eligibility criteria for AFOLU carbon projects, provides a definition of each criterion, and articulates ACR requirements specific to AFOLU project types. Project Proponents must also refer to Chapter 3 of the ACR Standard for additional requirements that apply to all project types. GHG Project Plans shall address each of these criteria.[37]

Table 4: Eligibility Criteria for AFOLU-Based Carbon Offset Projects

CRITERION	DEFINITION	REQUIREMENT
Start Date	For AR or Wetland restoration/revegetation projects, the Start Date is when the Project Proponent began planting or site preparation. For IFM, the Start Date may be denoted by one of the following:	AFOLU Projects must be validated within 3 years of the project Start Date. One exception applies to these timeframes: Projects using a newly approved methodol-ogy7 or a newly approved modification that expands the eligibility of a previously pub-

[36] http://www.epa.gov/climatechange/Downloads/ghgemissions/US---GHG---Inventory---2011---Chapter---7---LULUCF.pdf.

[37] A template for GHG Project Plans is available at http://www.americancarbonregistry.org/carbon-accounting/tools-templates.

CRITERION	DEFINITION	REQUIREMENT
	1. The date that the Project Proponent began to apply the land management regime to increase carbon stocks and/or reduce emissions relative to the baseline. 2. The date that the Project Proponent initiated a forest carbon inventory. 3. The date that the Project Proponent entered into a contractual relationship to implement a carbon project. 4. The date the project was submitted to ACR for listing review. Other dates may be approved by ACR on a case by case basis. For Avoided Conversion of non-forest, the Start Date is when the Project Proponent implemented the project action physically and/or legally, such as securing a concession or placing a land conservation agreement on the project land. For other Agricultural Land-based projects, the Start Date is the date by which the Project Proponent began the Project Activity on project lands, or the start of the cultivation year during which the Project Activity began.	lished methodology[8] may submit it for listing with ACR within 10 years of the project Start Date. However, the date of listing submittal must be within 6 months of the methodology publication date, and the project must then be validated within 2 years of the listing. The Start Date and the start of the Minimum Project Term shall be the same. The Start Date and the start of the first Crediting Period
Minimum Project Term	The minimum period for which a Project Proponent commits to project monitoring and verification. This requirement applies only to AFOLU projects that have had ERTs issued that are associated with GHG removals (sequestration). AFOLU projects that have	Project Proponents of AFOLU projects with a risk of reversal shall commit to a Minimum Project Term of 40 years. The minimum term begins on the Start Date, not the first or last year of crediting. The Minimum Project Term is a requirement of the Project Proponent, not necessarily of the landowner

CRITERION	DEFINITION	REQUIREMENT
	claimed only avoided emissions are not subject to this requirement.	(unless the landowner is the Project Proponent). ACR enters into legal agreements only with the Project Proponent. Agreements between Project Proponent and landowner may have a shorter term and/or a "buy-out" option, provided the Project Proponent commits to replace issued ERTs in the event a landowner opts to discontinue Project Activities. See Chapter 4 and Chapter 6. Project Proponents and landowners may continue AFOLU carbon activities beyond the Minimum Project Term, but ACR does not require monitoring or verification unless the Crediting Period is renewed. At the end of the Minimum Project Term, if the Project Proponent does not renew for another Crediting Period and continue monitoring and verification, ACR conservatively assumes that its activities have ceased and retains and may re-tire any remaining buffer contributions (if applicable)
Crediting Period	Crediting Period is the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. Crediting Periods are limited in order to require Project Proponents to reconfirm, at intervals appropriate to the project type, that the baseline scenario remains realistic and credible, the Project Activity re-	All AR projects shall have a Crediting Period of 40 years. All IFM projects shall have a Crediting Period of 20 years. Avoided Conversion projects on both forest and non-forest land with land conservation agreements in place[38] shall have a Crediting Period of 40 years, unless otherwise specified in chosen methodologies.

[38] All land conservation agreements must be employed with a specified duration longer than a project's minimum project term.

CRITERION	DEFINITION	REQUIREMENT
	mains additional, and GHG accounting best practice is being used. This is important because once a project has demonstrated its additionality, it is not required to do so again until applying to renew the Crediting Period.	Wetland Restoration/Revegetation projects shall have a Crediting Period of 40 years. The Crediting Periods for agriculture projects that avoid emissions by changing to lower GHG practices and those that include a soil sequestration component will be specified in the applicable methodology. Unless otherwise specified in the methodology, a Project Proponent may apply to renew the Crediting Period by complying with all then-current ACR requirements, re-evaluating the baseline scenario, reconfirming additionality, and using emission factors, tools, and methodologies in effect at the time of Crediting Period renewal. ACR does not limit the allowed number of renewals. Projects that are deemed to meet ACR additionality criteria are considered additional for the duration of their Crediting Period. If regulations or common practice change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal, but does not affect its additionality during the current Crediting Period. If a project chooses not to renew its Crediting Period, it must continue monitoring and verification activities for the duration of the Minimum Project Term.

CRITERION	DEFINITION	REQUIREMENT
Land Eligibility	Land eligibility restrictions may apply to certain types of offset projects.	For AR projects, Project Proponents shall provide documented evidence in the GHG Project Plan that no project areas have been cleared of trees within the 10 years prior to the project Start Date in order to establish an AR project; or if project lands have experienced loss of forest cover within the last 10 years, this loss was caused by fire or natural disturbance. Loss of forest cover due to fire or natural disturbance does not disqualify an AR project. Some reforestation projects require removal of non-tree vegetation to prepare the site and establish trees. An example is the removal of brush from areas where it has invaded after fire and prevented or significantly slowed the return of trees due to factors such as competition, water limitations, and lack of a nearby seed source. Brush removal for site preparation does not disqualify a reforestation project. Emissions from brush removal must be accounted for in the GHG Project Plan if they exceed the de minimis threshold.
Land Title	Land title is a legal term representing rights and interests in project lands.	For U.S. projects with GHG emissions reductions resulting from terrestrial sequestration, Project Proponents shall provide documentation of clear, unique, and uncontested land title. For international projects, Project Proponents shall provide documentation and/or attestation of land title; ACR may require a legal review by an expert in local law.

CRITERION	DEFINITION	REQUIREMENT
		Land title may be held by a person or entity other than the Project Proponent, provided the Project Proponent can show clear, unique, and uncontested offsets title. AFOLU projects that result only in the crediting of avoided emissions with no risk of reversal may not require demonstration of land title.
Natural Management Requirements	New plantations of forests and revegetation of wetlands will be carbon sinks regardless of the species planted. However, ACR requires that project plantations are designed within a minimum threshold for facilitating regrowth of species that contribute to an ecosystem with broad environmental benefits and avoid potential negative impacts.	For AR and Wetland Restoration/Revegetation projects, Project Proponents shall ensure that planting/regeneration of vegetation comprises at least 95% native species. Agricultural tree plantations shall be limited to small-scale agroforestry (under 1,000 ha, with demonstrable livelihood benefits). Exceptions to the native species requirement may be granted if the following can be demonstrated: • The non-native species can be considered naturalized or; • The non-native species does not negatively affect the local ecosystem (in terms of input use (including water, fertilizer, pesticides), invasiveness, competition, etc.
Permanent	Permanence refers to the longevity of removal enhancements and the risk of reversal (i.e., the risk that atmospheric benefit will not be permanent). Reversals may be unintentional or intentional. All AFOLU projects with emissions reductions derived from sequestration have a risk of reversal.	AFOLU Project Proponents shall assess reversal risk using ACR's Tool for Risk Analysis and Buffer Determination, and shall enter into a legally binding Reversal Risk Mitigation Agreement with ACR/Winrock that details the risk mitigation option selected and the requirements for reporting and compensating reversals.

CRITERION	DEFINITION	REQUIREMENT
		Proponents of terrestrial sequestration projects shall mitigate reversal risk by contributing ERTs to the ACR Buffer Pool or using another ACR-approved insurance or risk mitigation mechanism. All projects must adhere to ongoing monitoring, reversal reporting, and compensation requirements as detailed in relevant methodologies and legally binding agreements (e.g., the ACR Reversal Risk Mitigation Agreement).

A.4 BASELINES AND LEAKAGE

This chapter provides requirements on baselines and leakage for the broad categories of eligible AFOLU carbon project activities. Exceptions to these requirements may occur in specific methodologies.

A.4.1 Baselines: AR

The AR baseline scenario is the carbon stock present immediately prior to site preparation, or the most likely carbon stock in the absence of project implementation. If trees are present within the project boundary at the project start, Project Proponents may only count sequestration in pre-existing trees as offsets if growth of the trees is also projected in the baseline. If the Project Proponent does not intend to project growth of pre-existing trees in the baseline scenario, they should be excluded from the project boundary.

If natural forest regeneration is occurring or is likely to occur absent the project action, but the project action (planting, seeding, and/or the human-induced promotion of natural regeneration) accelerates the return to forest, then Project Proponents shall include the estimated natural regeneration in the without-project scenario in the baseline scenario.

Removals of any standing biomass as part of site preparation should be included in project accounting if these exceed the de minimis threshold.

A.4.2 Baselines: IFM

The IFM baseline scenario shall quantify and justify harvest and forest growth in the absence of a carbon project. Wood products must be accounted for in an IFM baseline scenario. Each methodology shall specify the approach to calculating carbon in long-lived and landfilled wood products.

For project-specific baselines, Project Proponents shall determine the baseline scenario by identifying credible alternative forest management scenarios to the proposed Project Activity, including historical and common practice forest management in the region, using the approach in an approved methodology. All forest management practices that are modeled in the baseline must be demonstrably legally and financially feasible. IFM baseline modeling must include all relevant legal constraints, including Safe Harbor Agreements, legally binding Best Management Practices, restrictions related to endangered or threatened species, and any conservation easements (in place more than 1 year prior to the Start Date).

Performance standard baseline approaches are allowed for IFM projects, and shall be approved on a case-by-case basis.

A.4.3 Baselines: AC-F

The baseline for AC-F projects is the conversion of forest to non-forest over time. Baseline scenarios for planned deforestation and U.S. AC-F to non-forest can be directly calculated. Unplanned deforestation must be modeled.

Avoiding deforestation displaces some use of the forest, often clearing of land for agriculture, or for developed uses such as buildings and roads. Therefore, activity-shifting leakage must always be considered for AC-F projects. Calculation of leakage must be specified in each methodology.

For unplanned deforestation, to determine the appropriate scale for setting a baseline, Project Proponents shall consider the cause of deforestation that the project will address, then consider the geographic range over which that activity is occurring. The goal is to determine potential leakage emissions from deforestation that have occurred across the entire area in which the project might have an effect.

For planned deforestation and AC-F to non-forest, Project Proponents shall consider the probability of conversion as well as the carbon stock of the post-deforestation/conversion land use. The baseline agent of deforestation/conversion (or at a minimum a class of agent) must be identified, and the methodology must address activity-shifting leakage emissions.

A.4.4 Baselines: Agriculture-Soil Carbon Enhancement

The baseline scenario for agriculture-soil carbon enhancement projects is quantified by estimating soil carbon stocks within the project area in the absence of project activities. The specific requirements for determining the baseline scenario will be specified in the chosen methodology. Selecting baseline stock changes can be based on common practice, historical trends, and scientific literature. Models may be used provided they are approved for use by the chosen methodology and/or ACR.

A.4.5 Baselines: Agriculture-Avoided Emissions

The baseline for Agriculture-Avoided Emissions projects is quantified by estimating the avoided emissions that result in a change from a high GHG practice to a low GHG practice. The baseline scenario shall represent the quantified emissions associated with higher GHG emitting practices. Baseline estimates shall be based on common practice, and emissions can be quantified using models, regional datasets, scientific literature, or other ACR-approved approaches. Each methodology will specify requirements for establishing baselines.

A.4.6 Baselines: Wetland Restoration and Revegetation

The baseline for Wetland Restoration and Revegetation projects is quantified by estimating the emissions from a degrading or subsiding wetland or salinization. Baseline could also be agricultural practices, open water, or seasonal wetlands. In each methodology, baseline and project activities shall be summarized per currently eligible geographies.

A.4.7 Baselines: Avoided Conversion of Non-Forest

The full project area must currently be under a single land use classification and have qualified as that classification for at least 10 years prior to the Start Date (or Implementation Date in the case of aggregated/PDA projects). It will remain as that classification throughout the Project Term, and is legally able to be converted and would be converted to alternate use in the absence of the Project Activity.

A.4.8 Leakage

If an AFOLU project displaces activities, the Project Proponent shall account for the activity shifting, either by quantifying actual emissions that result for leakage or by applying a verifiable default. The geographic scope of activity-shifting leakage assessments should be constrained to the area in which the Project Activity can reasonably be expected to have resulted in activity shifting.

Similarly, if an AFOLU project causes market effects leakage, it must be accounted. If AFOLU Project Activities cause a quantifiable, statistically significant decrease in supply of goods, then the methodology must provide an approach for addressing this (via peer-reviewed studies on market leakage rates or similar).

If AR Project Activities cause an increase in supply of emitting goods, ACR does not require Project Proponents to assess market leakage.

Projects that involve changes in hydrologic management practices (e.g., wetland restoration) must address the potential for ecological leakage (impacts outside the project boundary) caused by changes to the hydrologic regime as a result of project development.

More detailed leakage specifications in approved AR methodologies must be followed.

A.5 AGGREGATED AND PROGRAMMATIC DEVELOPMENT APPROACH PROJECTS

A.5.1 Risk Assessment

The Project Proponent shall assess general and project-specific risk factors for an aggregated or PDA project as for any other project. The risk rating is applied at the overall aggregate or PDA level. The risk of unintentional reversals may be lower for aggregated or PDA projects, because risk is diversified across a group of geographically dispersed project participants. The risk of intentional reversals could also be lower; in a large Aggregated Project, the probability is great that at least one project participant will choose to discontinue participation, but this probability is spread across multiple project participants and many acres so that the probability of intentional reversals significantly affecting the project as a whole is lower.

A.5.2 Carbon Stock Inventory and Monitoring of Sequestration-Based AFOLU projects

AFOLU projects with direct measurement of emissions removals resulting from sequestration in an aggregated or PDA project must meet the same accuracy and precision targets as non-grouped projects in order not to avoid a confidence deduction.

As noted in Chapter 2, ACR requires a 90% statistical confidence interval of sampling of no more than ±10% of the mean. If the Project Proponent cannot meet this target, then the reportable amount shall be the mean minus the lower bound of the 90% confidence interval, applied to the final calculation of emission reductions/removal enhancements.

For aggregated or PDA projects, the ±10% at 90% confidence precision target is applied at the level of the project overall. Project Proponents may use stratification to reduce inventory sampling intensity and cost to achieve this target. ACR advises Project Proponents to design projects within a single geographic region and relatively similar forest, land types, or crops, which combined with careful stratification as an initial inventory design step will help make the target achievable at reasonable costs spread across the overall project.

ACR does not require any minimum number of inventory plots per participating landholding (unless otherwise specified in the methodology) as long as the target is achieved for the project overall. ACR does not require individual landowner baseline inventories, as long as the Project Proponent has a stratified inventory meeting ACR requirements for the (aggregated) project overall. Arrangements with individual project participants regarding inventories, entry and exit, crediting, buffer contributions, and other factors are left to the discretion of the Project Proponent.

As with initial carbon stock inventories and soil sampling, standards for monitoring and verification are applied at the level of the overall project, whether it is a single large landholding or an aggregated or PDA project.

A.6 USE OF MODELS

Process-based biogeochemical models and empirical models may be approved for use under ACR-approved AFOLU methodologies to quantify emissions. The correct application of any such models shall be specified in the approved methodology. To be applicable, any model shall:

- Have the potential to model emissions from the relevant practice change(s) with consideration of relevent factors;
- Have been accepted in a peer reviewed scientific publication and/or been published by a government agency[39]; and
- Allow for the calculation of uncertainty in predicted emissions (as the root mean squared error (RMSE) for empirical models), meeting the relevant requirements for uncertainty assessments as stated in Section 2.B.3.

A.6.1 Requirements for Process-Based Biogeochemical Models

Process-based biogeochemical models must consider the following factors, where relevant:

- Atmospheric factors (e.g., atmospheric background concentrations of ammonia and CO_2, and nitrogen concentration in rainfall);
- Daily meteorology;
- Edaphic factors (e.g., clay content; bulk density; soil pH; SOC at surface soil[40]; soil texture; slope; depth of water retention layer; field capacity; wilting point);
- Cropping factors (e.g. crop type; planting date; harvest date; carbon-to-nitrogen ratio of the grain, leaf + stem tissue and root tissue; fraction of leaves and stem left in field after harvest; maximum yield);
- Tillage factors (e.g., number of tillage events, date and depth of tillage events);
- Fertilizer application factors (e.g., number of fertilizer applications; date of each fertilizer application; application method; type of fertilizer; fertilizer application rate; number of organic applications per year; date, type, carbon-to-nitrogen ratio and rate of organic amendment application); and
- Irrigation factors (e.g., number of irrigation events; date, type, and rate of irrigation event).

[39] ACR may also approve other models on a case-by-case basis via an ACR-lead peer review process.
[40] Depth as required by the process model.

For application of the selected model to the project area, the following criteria must be met: There must be a study or studies (e.g., scientific journals, university theses, local research studies, or work carried out by the Project Proponent) that demonstrate that the use of the selected model is appropriate for the IPCC climatic regions of 2006 IPCC AFOLU Guidelines[41] or the agroecological zone (AEZ) in which the project is situated using one of the following options:[42]

Option 1 The studies used in support of the project should meet the guidance on model applicability as outlined in IPCC AFOLU 2006 guidelines in order to show that the model is applicable for the relevant IPCC climatic region. The guidance notes that an appropriate model should be capable of representing the relevant management practices and that the model inputs (i.e., driving variables) are validated from country- or region-specific locations that are representative of the variability of climate, soil, and management systems in the country.

Option 2 Where available, the use of national-, regional-, or global-level AEZ classification is appropriate to show that the model has been validated for similar AEZs. It is recognized that national-level AEZ classifications are not readily available; therefore, this methodology allows the use of the global and regional classification.

Where a project area consists of multiple sites, it is recognized that studies demonstrating model validity using either Option 1 or Option 2 may not be available for each of the sites in the project area. In such cases, the study used should be capable of demonstrating that the following two conditions are met:

1. The model is validated for at least 50% of the total project area relevant to the practice change where the project area covers up to 50,000 ha; or at least 75% of the total project area where the project area relevant to the practice change covers more than 50,000 ha; and
2. The area for which the model is validated generates at least two-thirds of the total project emission reductions.

A.7 VALIDATION AND VERIFICATION

A.7.1 Validation and Verification Requirements

ACR definitions and requirements for independent validation and verification are provided in Chapter 9 and in the separate ACR Validation and Verification Standard.

[41] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_03_Ch3_Representation.pdf.

[42] IPCC. 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4: Agriculture, Forestry, and Other Land Use. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

A.7.2 Desk-based Verification on Request for New Issuance

At each interval that the Project Proponent requests issuance of ERTs (usually annually, but may be more or less frequent), the Project Proponent shall submit a verification statement that is the product of a desk-based audit by an ACR-approved verifier. If applicable, this audit may use satellite or other aerial imagery, or other means acceptable to the verifier, to verify project continuance and boundaries.

A.7.3 Full Verification Every 5 Years

ACR requires a full verification for all projects, including a field visit to the project site, no less frequently than every 5 years. In AR and wetlands restoration projects, several years may elapse between the project Start Date and significant carbon accrual in vegetation. These project types may defer their first verification up to 10 years after project validation. The scope of this verification should include such carbon stock measurements as the verifier requires to provide a reasonable level of assurance that the GHG assertion is without material discrepancy (per ACR's materiality threshold of ±5%). It should also include an updated assessment of the risk of reversal and an updated buffer contribution (if applicable).

Contingent upon Annual Attestations and desk-based audits, projects continue to be credited until the end of the fifth calendar year following the year in which the field verification was performed. For example, if there is a measurement event in June 2010, a calculation of carbon stocks in August 2010, and an initial verification in September 2010, ACR will continue crediting through the end of December 2015, provided the Project Proponent supplies its Annual Attestations and desk-based verification statements at the required intervals. The full verification with updated risk assessment also offers Project Proponents the opportunity to demonstrate that the risk of reversal has decreased, and thus decrease its contribution to the ACR Buffer Pool, as described in Chapter 5.

APPENDIX B: BUFFER POOL TERMS AND CONDITIONS

THESE BUFFER POOL TERMS AND CONDITIONS (the "Buffer Pool Terms") govern the use of the American Carbon Registry® Buffer Pool (the "ACR Buffer Pool") by a Project Proponent and apply to the ACR AFOLU Carbon Project Reversal Risk Mitigation Agreement.

B.1 CONDITIONS TO PARTICIPATION IN ACR BUFFER POOL

To use the ACR Buffer Pool in connection with a project, a Project Proponent must first satisfy the following conditions:

I. The Project Proponent must have entered into the American Carbon Registry® AFOLU Carbon Project Reversal Risk Mitigation Agreement for the project (as amended from time to time, the "Reversal Risk Mitigation Agreement").
II. There must be a GHG Project Plan for the project which, among other things, includes a risk assessment conducted in accordance with the ACR Tool for Risk Analysis and Buffer Determination, a risk category and an approved buffer contribution amount equal to a minimum percentage of the offsets issued by ACR in connection with the project (as amended from time to time due to updated ACR-approved risk assessments, the "Minimum Buffer Percentage").

B.2 DEFINITIONS

Terms capitalized in these Buffer Pool Terms but not defined herein shall have the meanings given such terms in the Reversal Risk Mitigation Agreement or, if not defined therein, shall have the meanings given such terms in the Definitions section of this ACR Standard (as in effect as of the execution date of the Reversal Risk Mitigation Agreement, the "ACR Standard").

B.3 BUFFER POOL ACCOUNT

ACR will establish an American Carbon Registry® Buffer Pool Account (the "Buffer Pool"), over which it has sole operational and management control, to hold the Buffer Contribution from the Project (as defined below). ACR shall have the right to hold buffer contributions from all agriculture, forest and other land use (AFOLU) carbon projects registered with ACR in one or more co-mingled accounts. As long as offsets deposited by a Project Proponent are retained in the Buffer Pool Account, the Project Proponent may not transfer, sell, pledge, retire, or otherwise dispose of such offsets.

In the event that ACR is no longer operational or able to manage the Buffer Pool Account, the account will be managed by ACR's parent organization, Winrock International ("Winrock") or a comparable, qualified organization of Winrock's election.

B.4 BUFFER POOL CONTRIBUTION

I. **ASSESSMENT OF RISK.** For AFOLU projects that have risk of Reversal, Project Proponent shall conduct a risk assessment addressing both general and project-specific risk factors using the ACR Tool for Risk Analysis and Buffer Determination. The output of the tool is an overall risk rating percentage for the project, translating into a number of offsets that will be deposited in the ACR Buffer Pool Account to mitigate the risk of reversals at the time of each issuance, the Minimum Buffer Percentage. The risk assessment, overall risk category and Minimum Buffer Percentage, and calculated buffer contribution amount shall be included in the GHG Project Plan and Monitoring Report. ACR evaluates the overall risk category and corresponding buffer contribution, and the VVB evaluates whether the risk assessment has been conducted correctly. If no Reversals occur, the project's risk category and Minimum Buffer Percentage can remain unchanged for five years. The risk analysis must be re-evaluated at least every five years, or coincident with the interval of required site visit verification except in the event of a Reversal, in which case the risk category and Minimum Buffer Contribution shall be re-assessed and re-verified immediately.

II. **BUFFER CONTRIBUTION REQUIREMENT AND TIMING.** As set forth herein and in the ACR Standard, concurrent with each issuance of offsets to the project, Project Proponent shall contribute offsets to the Buffer Pool Account equal to the respective annual volumes of offsets being issued within the relevant reporting period multiplied by the Minimum Buffer Percentage. Project Proponent may, at its option, contribute a number of offsets greater than the number required by application of the Minimum Buffer Percentage. The number of offsets contributed to the Buffer Pool Account shall be referred to as the "Buffer Contribution." In the event of an increase in the Minimum Buffer Percentage due to an updated risk assessment, Project Proponent shall make the required additional Buffer Contribution within ten (10) days following ACR's approval of the updated risk assessment.

III. **COMPOSITION OF BUFFER CONTRIBUTION.** The Buffer Contribution shall consist of offsets generated by the Project, offsets of any other type or vintage held in an ACR registry account by the Project Proponent, or any combination thereof.

B.5 REVERSAL

I. **NOTICE OF REVERSAL.** Project Proponent shall provide written notice to ACR immediately upon becoming aware of any Unintentional or Intentional Reversal or Early Project Termination decision. Such notice shall include the number of offsets affected by the Reversal (the "Estimated Lost Offset Amount"), a description of how the Estimated Lost Offset Amount was determined, a description of the nature and cause of the Reversal and all other relevant facts. Project Proponent shall, at its expense, promptly and fully comply with all ACR requests for additional information or analyses relating to the Reversal. ACR

requires the quantification of carbon stocks after the Reversal as verified by a VVB, at the Project Proponent's expense, to be reported to and confirmed by ACR (the "Verified Lost Offset Amount") within six months of the Reversal.

II. **LOSS MITIGATION FOR AN UNINTENTIONAL REVERSAL.** ACR mitigates the loss from an Unintentional Reversal by retiring from the Buffer Pool the Estimated Loss Amount at Project Proponent's expense (including payment of then-applicable offset retirement fees). If the Lost Offset Amount is less than the Project Proponent's net Buffer Contributions up to that time, then the Buffer Contributions cover the Reversal. If the Lost Offset Amount from the Reversal exceeds the Proponent's Buffer Contributions to date, the Project Proponent shall pay a "deductible" of 10% of the Lost Offset Amount, depositing this additional offset amount in the ACR Buffer Pool within thirty (30) days of the retirement, and the Buffer Pool covers the remainder. The deductible contribution may be of ACR offsets of any type and vintage. Following unintentional reversals, the Proponent is not required to replenish the buffer unless the Minimum Buffer Percentage increases based on the risk assessment update. If the Verified Lost Amount is greater than the Estimated Lost Amount, ACR will retire from the Buffer Pool the difference.

III. **LOSS MITIGATION FOR AN INTENTIONAL REVERSAL.** ACR mitigates the loss from an Intentional Reversal, which is assumed as all affected carbon stocks, by canceling the associated volume of credits from the Project Proponent's account and/or canceling or retiring from the Buffer Pool the Estimated Loss Amount (as applicable) at Project Proponent's expense (including payment of then-applicable offset activation, retirement and cancelation fees) upon notification by the Project Proponent. Cancelation of all non-transacted offsets will occur for a project that has terminated early and retirement will occur equivalent to any volume that has been transferred. The Project Proponent shall, at the Project Proponent's expense, contribute the Estimated Lost Offset Amount to the Buffer Pool Account within thirty (30) days of the Reversal. This Buffer Contribution may be made using ACR offsets of any type or vintage. If the Project Proponent does not make this Buffer Contribution within thirty (30) days, ACR retains the right to freeze the account and use any existing offsets to compensate for the Reversal.

The Verified Offset Amount must be submitted to ACR within six months of Reversal unless additional time is granted by ACR in writing. If the Verified Lost Amount is greater than the Estimated Lost Amount, Project Proponent shall contribute an additional amount for the difference, which will be retired by ACR.

IV. **EARLY PROJECT TERMINATION DUE TO REVERSAL.** Sequestration projects will terminate automatically if a Reversal, Intentional or Unintentional, causes project stocks to decrease below baseline levels prior to the end of the Minimum Project Term. In cases where this decrease is caused by intentional reductions to stocks (e.g., forest conversion or over-harvesting), which is considered an Intentional Reversal, the Project Proponent shall compensate for all issued offsets to that project following the process in III above.

V. **EARLY PROJECT TERMINATION.** If a Project Proponent opts to terminate the project at any time prior to the end of the Minimum Project Term by discontinuing project monitoring, verification and reporting activities for the Project (or subset of the project in an aggregated or PDA project) or leaves the carbon program, ACR conservatively considers the cumulative sequestration and/or emissions reductions from avoided conversion of the project to be lost (i.e., all offsets issued to the project). Project Proponents must compensate

for the full amount of all offsets issued cumulatively to the project upon termination. If only a portion of the project land owners (i.e., in the case of an aggregated or POA project) chooses to terminate, the remaining land owners may continue project activities if the area which was terminated is compensated. The Project Proponent shall have the responsibility to compensate for project termination following the process in III above.

In the case of Early Project Termination in order to re-enroll the project in another voluntary, state or federal program, the Project Proponent must compensate for all offsets issued to the Project following the process in III above. This is because ACR does not have the ability to enforce the actions of a Project Proponent on a project that is no longer registered on ACR.

VI. **RISK ASSESSMENT UPDATE.** Project Proponent shall comply with the risk assessment update requirements pursuant to the Reversal Risk Mitigation Agreement upon occurrence of a Reversal. Frequent recurring reversals will lead to a higher assessed risk and accordingly increased Minimum Buffer Percentage.

B.6 END-OF-TERM BUFFER POOL ACCOUNT BALANCE TRANSFER TO ACR

To the extent required under the ACR Standard, ACR shall, following the termination of the Project Term, decide to continue to hold or to retire any remaining offsets contributed to the Buffer Pool Account with respect to the Project. For purposes hereof, “Project Term” shall mean the period ending at the termination of the later of (i) the Minimum Project Term (including any renewals or extensions) and (ii) any additional period in which, pursuant to the ACR Standard, Project Proponent has agreed to document project continuance.

B.7 EVENTS OF DEFAULT; REMEDIES

The following events and circumstances shall constitute an Event of Default under these Buffer Pool Terms: (i) Project Proponent’s failure to notify ACR within ten (10) days after becoming aware of a reversal or Early Project Termination decision; (ii) Project Proponent’s failure to cure a breach of these Buffer Pool Terms within ten (10) days following notice of such breach by ACR to Project Proponent; (iii) the occurrence of an Event of Default under the Reversal Risk Mitigation Agreement; and (iv) a bankruptcy, receivership or other insolvency proceeding by or against Project Proponent and not dismissed within sixty (60) days of the making of a general assignment for the benefit of creditors, insolvency, or the institution of bankruptcy, reorganization, liquidation or receivership proceedings, by or against Project Proponent.

Upon the occurrence of an Event of Default, ACR may, in its sole discretion and without limitation of ACR’s right to pursue other available legal or equitable remedies, pursue any of the remedies set forth in the Reversal Risk Mitigation Agreement.

B.8 LIMITATION OF LIABILITY; INDEMNIFICATION

I. **LIMITATION OF LIABILITY.** In no event shall ACR, its owners, affiliates or subsidiaries, and their respective officers, directors, independent contractors, employees, agents, or donors (the "ACR Parties") be liable for damages arising out of or in connection with these Buffer Pool Terms, except to the extent caused by the ACR's negligence or willful misconduct.

UNDER NO CIRCUMSTANCES SHALL ANY ACR PARTY BE LIABLE FOR LOST PROFITS OR ANY SPECIAL, INCIDENTAL OR CONSEQUENTIAL DAMAGES ARISING OUT OF OR IN CONNECTION WITH THESE BUFFER POOL TERMS. NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT, IN NO EVENT SHALL THE AGGREGATE LIABILITY OF THE ACR PARTIES TO PROJECT PROPONENT OR ANY THIRD PARTIES UNDER OR IN CONNECTION WITH THESE BUFFER POOL TERMS EXCEED THE AMOUNT OF FEES PAID BY PROJECT PROPONENT TO THE REGISTRY UNDER THE ACR MEMBER AGREEMENT.

Project Proponent acknowledges and agrees that the foregoing limitations are independent of any remedy and will remain in full force and effect notwithstanding the failure of the essential purposes of any such remedy. The provisions of this section shall apply regardless of the form of action, damage, claim, liability, cost, expense, or loss, whether in contract, statute, tort (including, without limitation, negligence), or otherwise.

II. **INDEMNIFICATION.** Project Proponent agrees to indemnify and hold the ACR Parties harmless from any losses, damages, liabilities, judgments, settlements, fines, taxes, liens, impositions, encumbrances, penalties, claims, suits, costs and expenses, including reasonable attorneys' fees, arising out of or related to: (i) Project Proponent's breach of these Buffer Pool Terms; or (ii) violation by Project Proponent of any law or regulation, or the rights of a third party.

B. 9 MODIFICATIONS

ACR reserves the right, in its sole discretion, to augment, segment, reformat, reconfigure, delete elements of, or otherwise modify at any time these Buffer Pool Terms or create new types or versions thereof. ACR shall provide Project Proponent with at least thirty (30) days' prior notice of material modifications to the Buffer Pool Terms. Such modifications shall be effective upon the date set forth in the notice. Continued use of the American Carbon Registry® by Project Proponent after the effective date set forth in the notice shall constitute acceptance of such modifications.

B.10 NOTICE

All notices and other communications required, made or permitted hereunder shall be made in the manner set forth in the Reversal Risk Mitigation Agreement. ACR also may provide notices of changes to the ACR Standard, the Buffer Pool Terms or other matters by displaying notices or links to notices to Project Proponents generally on the American Carbon Registry® website.

APPENDIX C: NORMATIVE REFERENCES

The ACR Standard is based on the foundation laid by the normative reference standards and documents listed in Table 5 below. These documents assisted ACR to articulate its own requirements and specifications for the quantification, monitoring, and reporting of GHG project-based emissions reductions and removals, verification, project registration, and issuance of project-based offsets.

In particular, the ACR Standard builds on the ISO technical specifications for GHG accounting, GHG assertions and verification, and verifier accreditation as set forth in the ISO 14064 Parts 1-3:2006 and ISO 14065:2013, Specifications. To the ISO specifications, ACR adds its own mandatory requirements as detailed in the ACR eligibility criteria, additionality determination process, sector standards, and approved methodologies and tools. In the event of conflicts between the ACR Standard and the ISO technical specifications or other normative references, the ACR Standard shall take precedence.

Table 5: Normative References for the ACR Standard

AUTHORING BODY	DOCUMENT OR STANDARD	RELATIONSHIP TO ACR
International Standardization Organization (ISO)	• ISO 14064:2006 Parts 1-3: A set of international standards that address the quantification, reporting, and verification of GHG emissions and project reductions • ISO 14065:2013: Verifier accreditation requirements	ISO 14064:2006 provides a foundation for the ACR Standard with technical specifications for GHG accounting and reporting for projects and verification assertions. ISO 14065: 2007 specifies requirements for verifier accreditation.
Intergovernmental Panel on Climate Change (IPCC)	• Guidelines for National GHG Inventories • Good Practice Guidance • Fourth Assessment Report	Identification of best practices and options for GHG emission inventory development; methodological guidance and primary seed document for more specific guidance materials and standards

AUTHORING BODY	DOCUMENT OR STANDARD	RELATIONSHIP TO ACR
Clean Development Mechanism (CDM)	• Project-level baseline and monitoring tools and methodologies • Tool for the Demonstration and Assessment of Additionality • GHG sources and sinks significance test	ACR generally accepts approved CDM methodologies for baselines and monitoring. The CDM additionality tool informs ACR additionality tests and may assist Project Proponents in formulating additionality arguments.

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Methodology for GHG Emission Reductions through Truck Stop Electrification

Version 1.1

July 2013



A nonprofit enterprise of

WINROCK INTERNATIONAL

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This methodology was developed by ACR and IdleAir, and approved through the public comment and expert peer review process. ACR wishes to thank Ethan Garber and Cynthia Perthuis of IdleAir, as well as the three anonymous peer reviewers.

IdleAir wishes to express its gratitude to Neil Cohn of N-Flex and Seth Baruch of Carbonomics.

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1. BACKGROUND AND APPLICABILITY

1.1 Background on Truck Stop Electrification

Approximately 680,000 long-haul trucks[1] stop for extended periods (e.g. overnight) at truck stops and other locations during layover (rest) periods that are mandated by the U.S. Department of Transportation[2]. During this time, drivers will idle their engines to maintain a comfortable temperature in their cab compartments and to provide power to devices such as televisions, refrigerators, laptops, and microwaves. Extended engine idling results in the consumption of large amounts of diesel fuel and the release of greenhouse gases (GHGs), as well as other hazardous air pollutants. According to the U.S. Environmental Protection Agency (USEPA), freight trucks contribute approximately 21 percent of all GHG emissions in the transportation sector.[3] Currently only a small percentage of drivers utilize anti-idling technologies to prevent extended idling. The intent of this methodology is to create immediate incentives and sources of revenues to fund this critical technology transition.

There are a number of different technologies that can reduce idling. These include the following[4]:

- On-board equipment
- Automatic engine stop-start controls
- Auxiliary power units (APU) and similar devices
- Diesel-fired cab and block heaters
- Air-conditioners powered with battery or thermal storage[5]
- Electrified parking spaces at truck stops

Electrified parking spaces at truck stops include single-system electrification systems that require no on-board equipment and dual-system (shore power) options that allow drivers to plug in on-board equipment.

Installation of truck stop electrification (TSE) technologies is an idling reduction solution for locations where extended idling occurs. These technologies allow a driver to shut down the main propulsion engine of the diesel truck, eliminating all of the emissions associated with diesel engine idling. The type of TSE system eligible under this methodology draws power from the electric grid in order to provide heating, air conditioning, and electric power for in-cab devices. Even after deducting the emissions from electricity generation (project emissions), TSE systems can deliver substantial reductions when

[1] Figure based on US Census Bureau. 2002 Economic Census: Vehicle Inventory and Use Survey-- Geographic Area Series-- United States: 2002; EC02TV-US; U.S. Census Bureau: Washington, DC, December 2004.
[2] Federal Highway Administration Hours of Service ("HOS") regulations state that drivers may not drive beyond the 14th consecutive hour after coming on duty, following 10 consecutive hours off duty. See http://www.fmcsa.dot.gov/rules-regulations/topics/hos/index.htm.
[3] Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2008, USEPA, April, 2010.
[4] See http://www.transportation.anl.gov/pdfs/EE/605.PDF and http://www.transportation.anl.gov/pdfs/TA/536.pdf
[5] See Gaines, L. 2009. Sleep Cheap: How to Minimize Overnight Costs with Idling-Reduction Equipment. Presentation to the SAE Commercial Vehicle Engineering Congress and Exhibition, Rosemont, IL.

compared to the carbon dioxide (CO_2) produced from an idling engine. In addition, TSE systems improve in-cab air-quality, providing ancillary health benefits for occupants.[6]

General industry acceptance is that a Class 8 diesel truck burns around 1 gallon of fuel for each hour of idling. Further studies have shown that while this is the case on average, actual fuel consumption rates vary greatly depending upon engine model, size, and the throttle level (RPM) set during idling. For this reason, a temperature-sensitive model has been developed that accounts for the differing levels of engine RPM required to maintain a comfortable cab temperature. The model used in this methodology is based on daily high or low temperatures at the TSE location and is used to determine emission levels that occur in the absence of the TSE project.

To date, expansion of TSE locations has been limited. At the time of publication of this methodology, a total of 56 TSE stations in 17 states are listed by the US Department of Energy.[7] This equates to only 2,240 TSE equipped spaces out of the nearly 500,000 available spaces in the U.S. (see Section 3.2 and Table 2 for additional details of truck parking estimates). One of the major roadblocks to current TSE technology expansion is the upfront capital costs required to install the infrastructure-based technology. It is expected that the ability to generate and claim tradable carbon credits would strongly impact TSE financing options, and TSE could play a small but measureable role in mitigating GHG impacts from truck freight movement.

1.2 Methodology Objectives

This methodology addresses boundary definition, baseline determination, additionality, quantification of baseline and project GHG emissions, leakage, uncertainty, data collection and monitoring requirements, quality assurance/quality control, ownership of emission reductions, and permanence for a TSE offset project. A TSE Project refers to a carbon offset project registered on a voluntary GHG program, and may include a single TSE facility or many individual TSE facilities grouped into one project. See definitions in 1.4 and project boundary in 2.1.

The methodology provides the necessary guidance for a TSE Project Proponent to submit to ACR a GHG Project Plan that provides a complete description of the TSE project and a true and accurate representation of its net GHG emission reductions. This documentation shall be sufficient for ACR to certify the GHG Project Plan, for successful third-party validation and verification of the project, and ultimately for project registration and issuance Emission Reduction Tons (ERTs).

1.3 Applicability Conditions

In order to use this methodology a TSE project must meet all of the following conditions:

- The methodology is applicable to installation and use of single-system electrification technologies, and excludes dual-system electrification and on board anti-idling equipment such as cab or bunk heaters, coolant heaters, and auxiliary power units.

[6] See: "In-Cab Air Quality of Trucks Air Conditioned and Kept in Electrified Truck Stop" by Doh-Won Lee, Josias Zietsman, Mohamadreza Farzaneh, and Wen-Whai Li,Hector A. Olvera, John M. E. Storey, and Laura Kranendonk: http://tse.tamu.edu/pdfs/InCab_TRR.PDF.

[7] www.afdc.energy.gov/afdc/progs/tse_listings.php

- The TSE system must use grid-connected electrical power, and must operate with the truck's main propulsion (diesel) engine fully shut off. This methodology does not account for project emissions from the truck, only those from generation of electricity powering the TSE system.
- The methodology is not applicable to projects using electrified parking spaces for vehicles other than long-haul diesel engine trucks.
- The methodology is currently only applicable in the United States due to its use of U.S.-specific references and emission factors (e.g. for electric power emissions). Future versions may expand applicability outside the U.S.
- The project must result in a reduction of direct emissions through identifiable actions by the Project Proponent (provision of TSE services that result in a clear and measurable reduction in diesel engine idling hours).
- Emission reductions must be surplus to any reductions effectively required by existing enforced regulations, and additional to business-as-usual as demonstrated through application of a common practice-based performance standard (see Section 3).
- Both baseline (diesel engine idling) and project (electricity consumption) emissions must be quantified using accepted, transparent, and replicable measurement and calculation tools and techniques (see Section 4). Raw data must be available to verify measurements and calculations. The project proponent should also provide calibration records, and other quality control/assurance information, to support the level of certainty and significance of the data.
- Ownership of GHG emission reductions must be clearly demonstrable by contract or written agreement. TSE facility owners, TSE users and any other parties involved in the project must be identified (see Section 6).
- Measurement uncertainty, permanence, and leakage must be addressed and where necessary quantified and deducted from net GHG emission reductions.
- Community and environmental impacts must be net positive as defined in the *ACR Standard*, with the option of further certifications of environmental, social and sustainable development benefits.

1.4 Definitions and Acronyms

All definitions in the latest version of the *ACR Standard* apply and are not repeated here. This methodology uses the following additional terms:

AILEF	Anti-Idling Law Enforcement Factor Index
ASOS	Automated Surface Observing Systems maintained by the Federal Aviation Administration
eGRID	USEPA's Emissions & Generation Resource Integrated Database
EGC	Electricity Generating Company (used in eGRID)
EMFAC	California Air Resources Board's Motor Vehicle Emissions Inventory (EMFAC) model

ERT	Emission Reduction Tonne (ACR unit of exchange, equal to a verified GHG reduction of one metric tonne CO_2 equivalent)
kWh	kilowatt hours
MADIS	Meteorological Assimilation Data Ingest System managed by the National Oceanic and Atmospheric Administration
NERC	North American Electric Reliability Corporation
PCA	Power Control Area, a level of aggregation in eGRID
PWS	Personal Weather Stations
RPM	Revolutions per minute
SIP	State Implementation Plan
SSRs	Greenhouse gas sources, sinks and reservoirs
TSE	Truck Stop Electrification
TSE system	One or more units that allow drivers to link into an electrical connection to provide power to the truck.
TSE facilities	The entire truck stop equipped with TSE systems, which will have many single parking places or spots for individual trucks.
TSE project	The TSE carbon project registered on a voluntary GHG program. A TSE project may include a single TSE facility or many individual TSE facilities grouped into one project.
USDOT	U.S. Department of Transportation
USEPA	U.S. Environmental Protection Agency

1.5 Periodic Reviews and Revisions

ACR may require revisions to this methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project's activities. This methodology may also be periodically updated to reflect regulatory changes, common practice adoption rates, emission factor revisions, or expanded applicability criteria including new models of eligible TSE technologies. Before beginning a project, the Project Proponent should ensure that they are using the latest approved version of this methodology.

Once a GHG Project Plan is certified, it remains valid for the duration of the project Crediting Period regardless of methodology updates.

An Annual Attestation by the Project Proponent is required. Validation is required once per Crediting Period, and verification is required prior to any new issuance of ERTs, as described in the *ACR Standard*. ACR will review Annual Attestations and periodic verification statements and notify the Project Proponent of any required adjustments or corrections to these documents. Once a GHG Project Plan has been certified by ACR, the project may be listed. Once ACR has accepted a verification statement, ACR will register verified emission reductions as ERTs.

2. PROJECT BOUNDARIES

ACR defines the GHG offset project boundary to include a project's physical boundary, temporal boundary, and GHG assessment boundary (i.e. GHG sources, sinks and pools accounted for in the baseline and project scenarios).

2.1 Physical Boundary

The project boundaries will be confined to all TSE systems installed by a single Project Proponent in a continuous time frame or in contiguous phases. A single TSE project may include multiple TSE facilities, each with multiple TSE systems (parking spaces), provided the included facilities are clearly described in the GHG Project Plan.

Key data to calculate baseline and project emissions will be centrally managed and stored by the Project Proponent. The project boundary will be the physical area encompassing the TSE systems deployed by the Project Proponent within a timeframe specified in the GHG Project Plan.

2.2 Temporal Boundary

Per the *ACR Standard,* the project Start Date is the date on which the project began to reduce GHG emissions against its baseline. For TSE projects, the Start Date corresponds to each TSE facility's first operating hour.

Projects completing validation within one year of approval of this methodology may select a project start date up to three calendar years prior to the year in which validation is completed.[8]

Completed projects are eligible to earn ERTs as long as they comply with ACR guidelines on additionality and start date.

Per the *ACR Standard,* the project Crediting Period is the length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. TSE projects using this methodology will have a Crediting Period of ten (10) years. Crediting Periods may be renewed by re-submitting the GHG Project Plan in compliance with current ACR standards and criteria; re-evaluating the project baseline; demonstrating additionality; using ACR-approved baseline methods, emission factors, tools and methodologies in effect at the time of Crediting Period renewal; and undergoing validation and verification, as required.

2.3 GHG Assessment Boundary

The GHG assessment boundary encompasses all primary effects and significant secondary effects associated with the project. The GHG assessment boundary is used to identify the GHG emission sources, sinks and reservoirs (SSRs) that must be examined to quantify a project's GHG reductions, as well as SSRs that may be excluded from accounting either because they are insignificant or because exclusion is conservative (i.e. will lead to an underestimate of net GHG reductions).

For TSE projects, the two primary GHG effects to be evaluated are (1) the reduction of GHG emissions from idling of diesel engines and (2) indirect emissions from the off-site production of electricity

[8] And may include GHG reductions for the entirety of that calendar year.

consumed by TSE systems. Emissions from manufacture and installation of TSE facilities are excluded as insignificant relative to the project's net GHG reductions over the project lifetime.

Baseline emissions from diesel engine idling are quantified using emission factors derived from the California Air Resources Board's EMFAC model, as described in section 4.2. Project emissions from electricity consumption by TSE systems are quantified using USEPA Emissions & Generation Resource Integrated Database (eGRID) emission factors, as described in section 4.3.

Life-Cycle Emissions from Avoided Diesel Use. This methodology classifies as baseline emissions only the direct emissions from diesel combustion by truck engines. It does not attempt to estimate the full life-cycle emissions from diesel, including upstream emissions from production, refining and transport, and credit these to the TSE project. In doing so it would be difficult or impossible to ensure no double-counting, since the TSE project proponent does not have title to the upstream emissions, and therefore could not prevent the upstream sources responsible for diesel production, refining and transport from claiming those emission reductions from reduced diesel. Considering the difficulties in both quantification and title, and considering that not including the upstream emissions in the quantification of baseline emissions is conservative – will result in lower-than-actual baseline emissions, and thus lower-than-actual emission reductions credited to the TSE project activity – upstream emissions are excluded, consistent with the ISO 14064-2 principle of conservativeness.[9]

The GHG assessment boundary for TSE projects is shown in Table 1.

[9] International Organization for Standardization ISO) 14064-2:2006(E) - Greenhouse gases. Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements.

Table 1. GHG sources included in and excluded from the GHG assessment boundary.

	Gas	Included / Excluded	Justification
Baseline	CO_2	Included	CO_2 (carbon dioxide) is the major GHG emitted from diesel fuel combustion.
	CH_4	Excluded	While there are minor CH_4 (methane) emissions from diesel fuel combustion, no credit will be claimed for this reduction in order to ensure that the project emission reduction claims are conservative.
	N_2O	Excluded	While there are minor N_2O (nitrous oxide) emissions from diesel fuel combustion, no credit will be claimed for this reduction in order to ensure that the project emission reduction claims are conservative.
Project	CO_2	Included	CO_2 is the major GHG emitted from electricity generation.
	CH_4	Excluded	CH_4 represents a *de minimis* proportion of the emissions from electric power generation, in CO_2 equivalent terms, based on eGRID data.
	N_2O	Excluded	N_2O represents a *de minimis* proportion of the emissions from electric power generation, in CO_2 equivalent terms, based on eGRID data.

3. BASELINE SCENARIO AND ADDITIONALITY

3.1 Baseline Description

Per the *ACR Standard*, the GHG project baseline is a counterfactual scenario that forecasts the likely stream of emissions or removals to occur if the Project Proponent does not implement the project, i.e., the "business as usual" case.

In this methodology the baseline is defined by existing actual or historical emissions, i.e. the continued engine idling of long-haul trucks during extended periods of rest at rates typical of prevailing practice in the industry. The overwhelming majority of trucks are not equipped with a climate control system that can be operated without using the main propulsion engine.

The typical long-haul driver travels about 306 days a year.[10] When away from home, the long-haul driver rests in the truck. During most of these resting hours the engine is idled to provide the amenities necessary for a comfortable resting environment. Factors that influence the rate of idling include seasonal climate variation, industry structure, driver habits, company policy, etc. During periods of temperature extremes (summer and winter) drivers will idle their engines throughout the entire resting period to provide a comfortable in-cab temperature. During more moderate weather, drivers may elect to turn off the engine periodically for fuel savings.

3.2 Additionality Assessment

Emission reductions from the TSE project must be additional, or deemed not to occur in the business-as-usual scenario. Assessment of the additionality of a project shall be made based on passing two tests:

1. Regulatory Surplus Test, and
2. Practice-based Performance Standard

These two tests require the Project Proponent to demonstrate that the TSE project activity is surplus to regulations, i.e. the emission reductions achieved by idling reduction are not effectively required by any applicable and enforced regulation; and that the TSE project activity reduces emissions below the level established, through the practice-based performance standard as defined below, to represent common practice for the long-haul trucking industry in the United States.[11]

3.2.1 Regulatory Surplus Test

In order to pass the regulatory surplus test, the GHG emission reductions achieved by the project must not be effectively mandated by existing and enforced laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect as of the project Start Date.

[10] Based on a proprietary study by IdleAir Technologies Corporation, a survey of fleets with a total of more than 300,000 trucks indicated long-haul drivers were away from home on average 306 days per year and idling 11 hours per day during extended resting periods.

[11] Completed projects are acceptable as long as they comply with the *ACR Standard* requirements on additionality and start date.

The Project Proponent must demonstrate in the GHG Project Plan that there is no existing enforced regulation (federal, state or local) that mandates the project or effectively requires the GHG emission reductions associated with anti-idling technologies. The Project Proponent should consult the latest version of the *Idling Regulations Compendium* maintained by the American Transportation Research Institute as a reference for anti-idling regulations.[12]

Some states and municipalities have anti-idling regulations but provide exemptions to long-haul trucks for required rest periods, sleeper cabs, health and safety reasons, etc. In other jurisdictions regulations are "on the books" but routinely not enforced. Therefore there are four potential regulatory scenarios under this methodology:

- The jurisdiction (state, county, municipality etc.) where the TSE facility is located has an enforced anti-idling regulation → TSE systems are not eligible for crediting; these systems and associated GHG emissions must be excluded from the project.
- The jurisdiction where the TSE facility is located has an anti-idling regulation, but the trucks using TSE systems are exempted from the regulation → TSE systems are eligible for crediting, and application of the Anti-Idling Law Enforcement Factor (AILEF) in 3.2.2 is not required.
- The jurisdiction where the TSE facility is located has an anti-idling regulation, and no exemptions apply, but the Project Proponent believes there is systematic non-enforcement of the regulation → TSE systems may be eligible for crediting, but application of the AILEF is required.
- The jurisdiction where the TSE facility is located has no anti-idling regulation → TSE systems are eligible for crediting. Application of the AILEF is not required.

3.2.2 Demonstrating Non-Enforcement: AILEF Index

This methodology recognizes that prohibiting offset projects in all states that have anti-idling regulations "on the books," even if routinely non-enforced, will prevent the mechanism of carbon offset revenues from functioning to provide incentives for truck drivers and trucking companies to reduce idling. Prohibiting projects in such states would have the perverse result that the GHG reductions are achieved neither through voluntary actions nor regulations.

In jurisdictions where anti-idling regulations exist but are systematically not enforced, the methodology allows Project Proponents to work with an independent third-party nongovernmental organization (NGO) to develop and regularly update an *Anti-Idling Law Enforcement Factor (AILEF)* index reflecting the level of anti-idling enforcement in a particular state or region and discounting baseline emissions by this index. Discounting baseline emissions will reduce net emission reductions credited to projects.

The AILEF index will take into account all local and state data available on enforcement of anti-idling rules. Project Proponents will also work with an appropriate, independent NGO that will collect data, and/or verify data collected by the Project Proponent, to demonstrate non-enforcement. Project Proponents will specify before project commencement in the GHG Project Plan what data will be

[12] *Idling Regulations Compendium*. This compendium is continually updated by ATRI; the latest update must be used. May be viewed at http://www.atri-online.org/

collected and vetted by the NGO. The NGO will issue a letter at each verification saying what the enforcement level was during the period to be verified. Data will be based on public records such as truck miles, estimated rest time, citations issued and fines levied. The AILEF would be calculated as a percentage (e.g. 20% enforced) and that percentage will be used to discount baseline emissions for all TSE projects in the area where the AILEF applies (e.g. municipality or state). When enforcement is over 50% according to the AILEF, no more credits would be issued for the project. The AILEF must be updated annually.

To provide an example, Project Proponents and the third-party NGO could gather evidence, such as: total truck miles driven, number of trucks traveling through a state, hours of truck drivers resting and other overall measures of usage. That data can be compared with analysis on the numbers of citations issues and other evidence, including:

- Interviews with law-enforcement and other relevant public agencies to identify fines levied to vehicle operators violating anti-idling regulations.
- Interviews and/or studies and data from law-enforcement, transportation authorities and other public agencies, non-governmental organizations, universities, research institutes and other groups that have data on idling practices in states with anti-idling regulations.
- Interviews with fleet operators of trucks with records of all enforcement fines levied on their drivers.

This data will be used to compile an assessment, approved by the third-party NGO, on the level of non-enforcement and appropriate AILEF index. If the data suggests that tickets are issued for 5% of total trucks committing infractions, then AILEF would be 5% and baseline emissions would be discounted by 5%.

The AILEF deduction is applied in Equation (4) in section 4.2.4.

3.2.3 Practice-Based Performance Standard

Project proponents shall also demonstrate that TSE installations are not common practice. Such practice-based performance standards evaluate the penetration rates of a particular technology or practice within a relevant industry, sector or region. If penetration rates of a particular technology are especially low (e.g. 5% or less), it can generally be concluded the project activity is not common practice and, having been shown to be surplus to enforced regulations, is deemed additional.[13] The analysis below demonstrates that as of the time of methodology adoption, the market penetration of TSE technology is considerably below 5%, in fact less than 1%.

[13] For reference, EPA's Climate Leaders Program stated that "offset projects are required to achieve a level of performance with respect to emission reductions and/or removals that is significantly better than business-as-usual. EPA determines a performance threshold for additionality specific to each project type, by examining data sets of similar, recently undertaken or planned practices, activities or facilities in the same geographic region. This level of performance is presented in the form of an emissions rate, a technology standard, or a practice standard, as selected by EPA based on the characteristics of the data examined. The performance standard approach minimizes the risk of accepting a project that is not additional or rejecting a project that is additional. A performance standard approach also reduces the complexity, cost, and subjectivity of constructing individual project-specific reviews."

Since technology adoption rates change over time, the practice-based performance standard must be updated at appropriate intervals by re-examining data on penetration rates, so that a GHG program does not continue crediting a project activity that has become essentially business-as-usual.

This practice-based performance standard compares the number of heavy-duty truck parking spaces with TSE technology installed to the estimated total number of truck parking spaces, to derive a common practice (business-as-usual) market penetration rate of TSE technologies.

According to the USDOE TSE Site Locator[14], 56 truck stop locations, with 2,240 individual spaces, are equipped with TSE technology at the time of methodology adoption.

A 2002 *Study of Adequacy of Commercial Truck Parking Facilities*, completed by the Federal Highway Administration,[15] estimates a total of 3,382 commercial truck stop and travel plaza facilities along interstates, with an estimated total of 284,601 parking spaces, in addition to 1,771 public rest area facilities along interstates, with an estimated total of 31,249 parking spaces.

The same study estimates an annual growth rate of 5.1% for truck parking spaces at public rest areas and 6.5% for parking spaces at commercial facilities. Applying these projected growth rates through 2010 would yield an estimate of 471,013 parking spaces at commercial facilities and 46,522 parking spaces at public facilities by 2010. However these growth rates are likely to be overestimated, considering downturns in the economy since the study was published in 2002. It should be noted that state-level data is difficult to obtain, and the only national data is from 2002 – thus precise, up-to-date figures are not readily available.

Simply dividing the number of heavy-duty truck parking spaces currently equipped with TSE technology (2,240) by the estimated total number of parking spaces in 2002 (315,850) yields a penetration rate estimate for TSE technologies of 0.7%. Accounting for growth since 2002 in the number of total heavy-duty truck parking spaces, even if the actual growth rates have been less than the 5.1% and 6.5% projected by the Federal Highway Administration, would only decrease the estimated percentage penetration rate of TSE-equipped spaces.

Data for calculation of the performance standard is shown in Table 2.

Table 2. Estimates of TSE-equipped versus total heavy-duty truck parking spaces (nationwide)

	Locations	Spaces
TSE-equipped, based on USDOE TSE Site Locator	56	2,240
Total commercial facilities as of 2002, based on FHA *Study of Adequacy of Commercial Truck Parking Facilities*	3,382	284,601

[14] See Department of Energy, Alternative Fuels and Advanced Vehicle Data Center. At time of publishing this methodology, the AFDC has its website at http://www.afdc.energy.gov/afdc/vehicles/idle_reduction_stations.html.

[15] *Study of Adequacy of Commercial Truck Parking Facilities*. Published by the Federal Highway Administration. At the time of this methodology's publishing, the report can be accessed at http://www.fhwa.dot.gov/publications/research/safety/01158/index.cfm.

Total public facilities as of 2002, based on FHA study	1,771	31,249
Total commercial + public as of 2002	5,153	315,850
Conservative estimate of TSE penetration (today's TSE-equipped spaces divided by 2002 totals)		0.7%
Total estimated commercial facilities in 2010, based on 6.5% annual growth rate		471,013
Total estimated public facilities in 2010, based on 5.1% annual growth rate		46,522
Total commercial + public, 2010 estimate		517,535
Estimate of TSE penetration (today's TSE-equipped spaces divided by 2002 totals projected forward to 2010 at FHA-estimated annual growth rates)		0.4%

This analysis shows that as of methodology adoption, the market penetration rate of TSE technologies is between 0.4% and 0.7%. We can conservatively estimate that the penetration rate is *at most* 0.7%, which is based on dividing today's number of TSE-equipped parking spaces by the 2002 number of total parking spaces. Any growth in the number of total parking spaces -- even if at less than the 5.1% and 6.5% annual rates, for public and commercial respectively, projected by the Federal Highway Administration in 2002 -- would cause the calculated percentage penetration rate for TSE technologies to be lower than 0.7%.

This indicates that the installation of TSE technologies at travel centers is not common practice. Therefore TSE projects meeting the applicability conditions of this methodology are deemed "beyond business-as-usual" and thus additional, provided they pass the Regulatory Surplus test. Project Proponents must show that the project is surplus to enforced regulations, including application of the AILEF index if required, but need not document project-specific financial, institutional, or technological implementation barriers.

Projects that are certified under this version of the methodology need not reassess additionality during the Crediting Period. However, since additional TSE installations will increase the market penetration rate, the practice-based performance standard must be reassessed periodically after significant changes to the market, or at a minimum every 10 years, to re-evaluate the penetration rate of TSE installations at travel centers. If the penetration rate of TSE systems reaches 5% of total parking spaces in the country, then new projects started after that 5% level is reached will be considered to not have met the Performance Standard.

ACR reserves the right to review the common practice assessment as necessary to ensure additionality of future projects. All new GHG Project Plans, and all applications for Crediting Period renewal on

existing projects, shall apply the regulatory surplus and practice-based performance standard tests in the latest approved revision of this methodology in effect at the time of GHG Project Plan submission or application for Crediting Period renewal.

4. QUANTIFICATION OF BASELINE AND PROJECT EMISSIONS

Please see Appendix A for a worked example of the baseline, project, and net GHG reductions calculations in this chapter.

4.1 Activity Data

The quantification of baseline and project emissions using emission factors depends on reliable and complete measurement of activity data – in this case the usage of TSE systems by participating long-haul truckers. The Project Proponent must describe in the GHG Project Plan a system for accurately monitoring, recording, and storing data on customer usage of the TSE systems included in the project boundary, thereby validating hours of usage by location for emission reduction calculations.

An acceptable system is one that monitors electric power usage at the truck stop facility. TSE usage will be measured by a mechanism separate from electricity metering. The truck will drive up to the TSE unit, open a module to swipe a credit or member card. Then the billing will start hourly. When the driver disconnects, another time stamp will occur, which is logged into a database. This is how TSE usage monitoring will occur. Kilowatt-hours will be calculated through traditional utility meters with the power company sending bills at the end of the month with kWh usage. If Smart Meters are available, the TSE facility will be able to have time-of-day usage data as well.

If on-site power meter records are not available, for example in the early stages of project implementation, utility receipts may be used. In these instances, electric power consumption from the utility receipt should be pro-rated into the appropriate calendar periods to match the time frame of the accumulated TSE usage hours.

Activity data will be spot-checked by the verifier.

4.2 Baseline Emissions

4.2.1 Emission Factors

A 2002 EPA study concludes that during an hour of idling, a heavy-duty diesel engine consumes between 0.4 and 1.65 gallons of diesel fuel and releases anywhere between 4,000 and 16,000 grams of CO_2. The EPA study, along with other studies, shows that fuel consumption and resulting emissions are most directly affected by engine RPM settings. For this reason, this methodology uses a temperature-adjusted emissions model that accounts for the differing levels of engine RPM that would be necessary to maintain a comfortable cab temperature, in the absence of idle reduction technology, based upon daily high or low temperature at the TSE location. This model is applied to the actual hours of TSE system usage at a site to derive baseline CO_2 emissions.

The baseline emission factors used in this methodology are derived from an October 2002 EPA publication as well as more recent data from the California Air Resources Board's Motor Vehicle

Emissions Inventory (EMFAC) model.[16] In the 2002, two-year study, 42 tests were conducted on nine Class-8 trucks of various model years. The study concludes that:

- During an hour of idling, a heavy-duty diesel engine consumes between 0.4 and 1.65 gallons of diesel fuel, depending strongly on the throttle setting (RPM);
- It is general practice to idle a diesel engine up to and, in some cases, higher than 1,000 RPM when accessory loads are present, such as to provide heating or air conditioning to the cab;
- Truckers can reasonably be expected to operate their heaters on days when the temperature is below 50 degrees Fahrenheit and operate the air conditioning on days when the temperature is above 70 degrees Fahrenheit;
- Based on the arithmetic mean for all tests, irrespective of engine RPM, 8,224 grams of CO_2 are released in each hour of diesel engine idling;
- The average rate of CO_2 released from idling trucks (grams/hour) tested at a low RPM (600-800) and tested at a high RPM (1,000-1,200) are 5,805 grams/hr and 11,815 grams/hr, respectively.

The key results of the study are summarized in Table 3.

Table 3. High, Low, and Average CO_2 Emissions and Fuel Consumption Rates for Class 8 Trucks (Han Lim 2002)

	CO_2 (g/hr)	Gal/hr
High Value	16,578	1.65
Low Value	3,915	0.39
Average Value	8,224	0.82
Standard Deviation	3,571	0.40
Coefficient of Variation	0.43	0.43
Low RPM Average (600-800 RPM)	5,805	0.58
High RPM average (1,000-1,200 RPM)	11,815	1.18

[16] U.S. EPA (Han Lim). October 2002. *Study of Exhaust Emissions from Idling Heavy-Duty Diesel Trucks and Commercially Available Idle-Reducing Devices*. This study generated preliminary emissions values of 144 grams/hr NOx, 8,224 grams/hr CO_2, and fuel consumption of 0.82 gal/hr.

In addition to this data, the California Air Resources Board recently published updated data from the Motor Vehicle Emissions Inventory (EMFAC) model related to heavy duty diesel trucks (HHDDT). Table 4 gives updated NO_x and CO_2 idle emission rates for HHDDT.

Table 4. NO_x and CO_2 idle emission rates (g/hour) based on CARB EMFAC model

Model Year Group	NOx			CO2		
	Low Idle	High Idle for Summer	High Idle for Winter	Low Idle	High Idle for Summer	High Idle for Winter
Pre-1987	45.7	95.9	82.2	4,271	9,822	7,687
1987-1990	70.2	147	126	4,507	10,365	8,112
1991-1993	78.4	165	141	4,610	10,603	8,298
1994-1997	85.3	179	153	4,713	10,840	8,483
1998-2002	92.1	193	166	4,846	11,145	8,722
2003-2006	95.5	201	172	4,934	11,349	8,882
2007-2009	30.0	63.0	54.0	4,934	11,349	8,882
EPA2007	30.0	63.0	54.0	4,934	11,349	8,882

Source: EMFAC 2011, Technical Documentation, Sept. 2011, California Air Resources Board, p. 122.

Based on these data the high-idle rate is 11,349 gCO_2/hour and the low-idle rate is 4,934 gCO_2/hour. The methodology therefore adopts these numbers as the baseline emissions factors because they are based on more recent information and are more conservative (i.e. will result in slightly lower baseline emissions, and therefore a lower estimate of net GHG reductions credited to the TSE project activity) as compared to the Lim 2002 numbers.

It should be noted that fuel consumption during extended idling depends on RPM, accessory loads (e.g., compressor), and hotel loads (HVAC, in-cab appliances). There are very large differences in fuel consumption among trucks, even under similar loading. This indicates that there will be some evolution in emission factors over time. Additional studies have also been published.[17,18]

4.2.2 Survey of TSE Clients

For conservative crediting, it is important to ensure that the baseline emission rates (gCO_2/hour) from diesel engine idling are not overestimated. This version of the methodology uses recent (EMFAC 2011) baseline emissions rates, which show a slight improvement in diesel engine efficiency compared to the 2002 EPA study. Besides tracking efficiency improvements over time, collecting data on the actual TSE system users can help determine whether their trucks are systematically more or less efficient than the average trucks on which the gCO_2/hour baseline emission rates are based.

The Project Proponent shall collect truck model year information for a representative sample of TSE customers when they register in the Project Proponent's member database. The survey will require ±10% precision at a 90% confidence interval. If the sample size does not reach this level of precision, then the actual uncertainty (i.e. margin of error) will be deducted from the baseline emissions. For

[17] Stodolsky, Gaines, and Vyas. *Analysis of technology Options to Reduce the Fuel Consumption of Idling Trucks.* June 2000.
[18] Lambert, Vojtisek-Lom, and Wilson. *Roadside Emissions Study – Preliminary Results for Stationary and On-Road Testing of Diesel Trucks in Tulare, CA.* Clean Air Technologies, April 2002.

example, if the margin of error is ±3% based on the survey, then $BE_{project}$ in Equation (4) will be discounted by 3%.

Using data from the survey of TSE customers, the Project Proponent shall conduct an annual assessment whether the average age of TSE customers' trucks is less than five (5) years. If the average age is less than 5 years, the baseline emission rates above will be discounted by 5% (in addition to any margin-of-error deduction) based on the conservative assumption that these trucks may be more efficient (lower-emitting) than the average trucks on which the EMFAC emission rates are based. Thus:

- If the survey indicates that average age of trucks using the TSE systems is less than 5 years, the high-idle rate of 11,349 gCO_2/hour will be replaced with 10,782 gCO_2/hour, and the low-idle rate of 4,934 gCO_2/hour will be replaced with 4,687 gCO_2/hour.
- If the survey indicates that average age of trucks using the TSE systems is 5 years or greater, the EMFAC rates of 11,349 gCO_2/hour high-idle and 4,934 gCO_2/hour low-idle will be used for all trucks.

4.2.3 Temperature Adjustment

Because TSE systems are a stationary technology, it is possible to determine the daily temperature at each TSE location. Projects can also use differing emission factors that result from variations in engine RPM. Therefore by correlating engine RPM to average daily temperatures, it is possible to calculate baseline CO_2 emissions from diesel idling to maintain a comfortable cab temperature and operation of accessories. Climate control is the main reason drivers idle their engine, followed by the need to operate electrical accessories.[19]

To portray the temperature experienced during idling periods, average daily low or high temperatures are used. Low temperatures typically correspond with overnight lows, which are the times in which the majority of drivers lay over at truck stops, and also the time that idle reduction equipment experiences the highest usage.

For days when the daily low temperature is below 50 degrees Fahrenheit, or the daily high temperature is above 70 degrees Fahrenheit, this methodology assumes drivers are operating climate control equipment as well as electrical accessories and therefore idle their engines at the higher 1,000-1,200 RPM rate, emitting on average 11,349 g CO_2/hr (per the California Air Resources Board EMFAC data). During days when the daily low and high temperature is between 50 and 70 degrees, the methodology assumes drivers are only operating electrical accessories and therefore idle their engines at the lower 600-800 RPM rate, emitting on average 4,934 g CO_2/hr).

4.2.4 Baseline Emissions Equations

If the daily low temperature during day *X* at TSE location *Y* is below 50 degrees Fahrenheit, or above 70 degrees Fahrenheit, then:

$$BE_{dayX,locY} = (EF_{high} * Hours_{TSE}) / 1{,}000{,}000 \quad \textbf{(1)}$$

[19] Lutsey, Brodrick, Sperling and Oglesby. *Heavy-Duty Truck Idling Characteristics – Results from a Nationwide Truck Survey*. Submitted to TRB 2004.

Where:

$BE_{dayX,locY}$ Baseline emissions during day *X* at TSE location *Y*; metric tons CO_2

EF_{high} "High-idle" emission factor from California Air Resources Board Motor Vehicle Emissions Inventory (EMFAC) model = 11,349 gCO_2/hour (or 10,782 gCO_2/hour if survey of TSE customers per 4.2.2 indicates average age of trucks is less than 5 years)

$Hours_{TSE}$ Hours TSE systems were used, based on measured activity data, during day *X* at location *Y*

1,000,000 Conversion from grams to metric tons CO_2

If the daily low or high temperature during day *X* at TSE location *Y* is between 50 and 70 degrees Fahrenheit, then:

$$BE_{dayX,locY} = (EF_{low} * Hours_{TSE}) / 1{,}000{,}000 \quad \textbf{(2)}$$

Where:

$BE_{dayX,locY}$ Baseline emissions during day *X* at TSE location *Y*; metric tons CO_2

EF_{low} "Low-idle" emission factor from California Air Resources Board Motor Vehicle Emissions Inventory (EMFAC) model = 4,934 gCO_2/hour (or 4,687 gCO_2/hour if survey of TSE customers per 4.2.2 indicates average age of trucks is less than 5 years)

$Hours_{TSE}$ Hours TSE systems were used, based on measured activity data, during day *X* at location *Y*

1,000,000 Conversion from grams to metric tons CO_2

Then summing across days and across TSE facility locations included in the project:

$$BE_{locY} = \sum_{day=1}^{365} BE_{dayXlocY} \quad \textbf{(3)}$$

And

$$BE_{project} = \sum_{Y=1}^{n} BE_{locY} \times (1 - (AILEF / 100)) \times (1 - ME_{survey}) \quad \textbf{(4)}$$

Where:

BE_{locY}	Baseline emissions at TSE location *Y*, summed over the year; metric tons CO_2
$BE_{dayX,locY}$	Baseline emissions during day *X* at TSE location *Y*; metric tons CO_2
$BE_{project}$	Baseline emissions across all TSE locations included in project, summed over the year; metric tons CO_2
Y	1, 2, 3 ... *n* locations included in the TSE project
AILEF	Anti-Idling Law Enforcement Factor Index (percentage), as described in 3.2.2. Set AILEF = 0 if there is no anti-idling regulation, or the trucks using TSE systems are exempted from the anti-idling regulation. If the AILEF exceeds 50%, no emission reductions will be credited to the TSE Project
ME_{survey}	Margin of error of the survey of TSE customers, per 4.2.2, if the target of +/- 10% precision at a 90% confidence interval is not met. If this target is met, set ME_{survey} = 0.

4.3 Project Emissions

4.3.1 Emission Factors

The TSE systems eligible under this methodology allow the truck driver to shut down the main propulsion engine completely. Thus in the project scenario there is no need to measure emissions from the truck's diesel engine. Only emissions from electricity generation, used to power the TSE system, are quantified and deducted from baseline emissions to derive the calculation of net GHG emission reductions.

The CO_2 emissions from power generation are estimated using data from the USEPA's Emissions & Generation Resource Integrated Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of electric power generated in the United States, including emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide, net generation, resource mix, and other attributes.[20] As of adoption of this methodology, the latest release is eGRID2012 version 1.0, containing data through 2009. The latest published version of eGRID shall always be used.

eGRID2012 provides data organized by power control area (PCA), North American Electric Reliability Corporation (NERC) region, eGRID subregion, U.S. state, and other levels of aggregation. The PCA, eGRID subregion, and NERC region data are based on electricity generation, transmission and distribution areas so effectively represent the emissions associated with the mix of GHG-emitting and non-emitting resources used to serve electricity loads in those areas.

The Project Proponent shall use emission factors from the latest version of eGRID available. The Proponent should download, from the eGRID website, the data files spreadsheet. For eGRID2012 Version 1.0, this is called "eGRID2012 year 2009 data files.xls". Note the "Contents" tab shows the various levels of aggregation included in the other spreadsheet tabs.

[20] See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

To calculate CO_2 emissions from the electric power consumed by TSE systems included within the project boundary, the Project Proponent will multiply total kWh consumed for that TSE location and reporting period by one of the following eGRID emission factors, drawn from the data spreadsheet.

Note: The data aggregation levels are to be used in the order of preference below; i.e. if the PCA can be identified the emission factor from this tab must be used. Only if it is not possible to use the preferred level of aggregation is it permitted to move to the next level.

1. In eGRID2012 version 10, the **PCAL09** tab has data for 119 Power Control Areas across the United States. This methodology considers those PCA emission factors to be the most precise representation of emissions caused by TSE systems and thus requires the PCA emission rate to be used as long as the PCA can be identified. In the **PCAL09** tab, look up the appropriate PCA in the left-hand column and scroll across to the column giving the **PCA annual CO_2 total output emission rate** in lb/MWh.
2. *Only if the PCA is not known*, use the eGRID subregion data in the **SRL09** tab. This includes emission factors for 26 eGRID subregions covering the United States (see "eGRID2012_eGRID subregion representational map," reproduced in Annex B). Look up the appropriate eGRID subregion in the left-hand column and scroll across to the column giving the **eGRID subregion annual CO_2 total output emission rate** in lb/MWh.
3. *Only if the PCA is not known **and** it is not feasible to place the TSE facility definitively in an eGRID subregion* (e.g. because it is located near a boundary between two subregions), use the data aggregated by U.S. state in the **ST09** tab. This will be the least precise because electricity generation, transmission and distribution regions do not follow state boundaries. Look up the state where the TSE facility is located in the left-hand column and scroll across to the column giving the **State annual CO_2 total output emission rate** in lb/MWh.

4.3.2 Project Emissions Equations

Calculate project emissions using the following equation:

$$PE_{dayX,locY} = (kWh / 1{,}000) * (Rate_{eGRID} / 2{,}205) \quad \textbf{(5)}$$

Where:

$PE_{dayX,locY}$	Project emissions from electricity consumed during day *X* at TSE location *Y*; metric tons CO_2
1,000	Conversion from kWh to MWh
$Rate_{eGRID}$	eGRID emission rate for CO_2, by (in order of preference) PCA, eGRID subregion, or State; lb/MWh
2,205	Conversion from lb/MWh to metric tons/MWh

Then summing across days and across TSE facility locations included in the project:

$$PE_{locY} = \sum_{day=1}^{365} PE_{dayXlocY} \quad \textbf{(6)}$$

And

$$PE_{project} = \sum_{Y=1}^{n} PE_{locY} \quad \textbf{(7)}$$

Where:

PE_{locY}	Project emissions at TSE location *Y*, summed over the year; metric tons CO_2
$PE_{dayX,locY}$	Project emissions during day *X* at TSE location *Y*; metric tons CO_2
$PE_{project}$	Project emissions across all TSE locations included in project, for the year; metric tons CO_2
Y	1, 2, 3 ... *n* locations included in the TSE project

4.4 Leakage

Leakage is defined as an increase in emissions outside the project boundary attributable to the implementation of the project. In cases where leakage occurs, it must be accounted for and subtracted from the reported net GHG emission reductions for the verification period.

Potential types of leakage include activity shifting (a shifting of GHG-emitting activities outside the project boundaries due to the project) and market effects (an increase in GHG-emitting activities due to unchanged market demand for a good or service whose supply is decreased due to project activities).

In this case because reduction in idling and use of TSE systems does not increase idling outside the project boundaries, nor affect the quantity of goods and services produced, nor cause any other expected significant increases in emissions outside project boundaries, leakage is assumed to be zero.

4.5 Emission Reductions

Net GHG emission reductions achieved by the TSE project, prior to accounting for uncertainty, are calculated as:

$$ER_{prelim} = (BE_{project} - PE_{project}) * (1 - LK) \quad \textbf{(8)}$$

Where:

ER_{prelim}	Preliminary calculation of net emission reductions across all TSE locations included in project, for the year, prior to accounting for uncertainty; metric tons CO_2
$BE_{project}$	Baseline emissions across all TSE locations included in project, summed over the

	year, as derived in Equation (4); metric tons CO_2
$PE_{project}$	Project emissions across all TSE locations included in project, summed over the year, as derived in Equation (7); metric tons CO_2
LK	Leakage discount; here LK = 0 as described in section 4.4

4.6 Uncertainty

4.6.1 Sources of Uncertainty

The emission reduction calculations in this methodology are designed to minimize the possibility of overestimation and over-crediting of GHG emission reductions due to various uncertainties, primarily associated with emission factors and representative sampling populations.

There are several uncertainties related to estimates of GHG emission reductions from TSE projects. Some of these uncertainties are more easily quantified than others. These include:

- *Emission factors.* CO_2 emissions from the idling of diesel engines are estimated using the emission factors in the 2011 EMFAC data cited in section 4.2.1. CO_2 emissions from the generation of electricity consumed by TSE systems are estimated using eGRID emission factors by PCA, eGRID subregion, or aggregated State-level data.
- *Activity data.* The measurement of TSE activity is not a source of uncertainty. The TSE operator is assumed to track precisely the duration of system usage and kWh consumption, and this data will be collected, verified, recorded, and reported as an integral part of the TSE project activity.
- *Induced Demand.* In the early stages of adoption of an innovative technology, encouraging trial and adoption is a critical challenge. Drivers must be induced to adjust longstanding behaviors and attitudes. To encourage driver trial and adoption, some TSE companies have packaged numerous benefits and services along with their HVAC services. This potentially could induce drivers to use the TSE system when they would not have idled their trucks otherwise. However this sort of use would be costly to the driver and/or their employer, and would not return fuel savings to the truck owner. During this phase in the evolution of the idle reduction industry, TSE operators generally do not perceive “gratuitous use” to be a driving factor. The impact of local weather on TSE usage is direct evidence that primary demand (the direct substitution of idling) is far greater than induced demand.
- *Life-Cycle Emissions from TSE system deployment.* TSE facility life-cycle emissions could be potentially reduced if the process of manufacturing and deploying TSE systems was itself carbon intensive. For the purposes of this methodology, since TSE operators generally do not manufacture their systems and lack reliable information about the carbon intensiveness of systems built and installed by contractors, emissions from construction are ignored and assumed to be *de minimis* relative to the overall emission reductions over the full TSE facility life.
- *Environmental influences and operating errors.* The variation in TSE system efficiency due to environmental influences or operating practices may also contribute to overall uncertainty.

Operating malfunctions of the project, if any, shall be recorded and the project activity data shall be adjusted to correct for faulty or missing data. The contribution of this variation to overall uncertainty expected to be small.

- *Survey of Truck Owners*: Project Proponents will survey TSE customers per 4.2.2 to determine the age of their trucks. There is some inherent uncertainty in any statistical sample, and this survey will require a 10% precision and a 90% confidence factor. If the sample size does not reach this level of precision, then the actual uncertainty, specifically the margin of error, will be deducted from $BE_{project}$ in Equation (4).

These potential sources of uncertainty, and the associated QA/QC program elements designed to minimize them, are summarized in Table 5.

Table 5. Uncertainties and Mitigation Procedures

Data Parameter	Uncertainty Level of Data	QA/QC Procedures Risk Mitigation
Number of TSE systems	Very low	TSE operator will have comprehensive records of the number of TSE systems installed, in operation, and used by truckers.
Operating time of TSE systems (hours)	Very low	TSE operator will track precisely the duration of system usage. Usage will be time-stamped, allowing the operator to know during which day usage occurred and apply the correct emission factor based on average daily low or high temperature at the TSE location.
Daily low or high temperatures	Very low	Weather data will be acquired from publicly available sources, originating from weather stations in the closest proximity to project locations. Data sources include historical weather station readings from: 1) Automated Surface Observing Systems (ASOS) stations maintained by the Federal Aviation Administration,[21] Meteorological Assimilation Data Ingest System (MADIS) stations managed by the National Oceanic and Atmospheric Administration,[22] and other Personal Weather Stations that have certified quality controls (PWS Network).
Electricity consumed by TSE systems (kWh)	Very low	TSE operator will track precisely the electricity consumed by TSE users. Electricity meters will be subject to a regular maintenance and testing regime to ensure accuracy. Their readings will be checked by the electricity distribution company. Any faulty or missing activity data shall be adjusted and corrected to ensure that net GHG emission reductions are not overestimated.

[21] See http://www.faa.gov/air_traffic/weather/asos/.
[22] See http://madis.noaa.gov/.

Data Parameter	Uncertainty Level of Data	QA/QC Procedures Risk Mitigation
Emission factors (baseline)	Low/medium	Variation and uncertainty does exist in the 2011 EMFAC emission factors for diesel engine idling. The CO_2 numbers are very similar to those in Han Lim 2002, indicating that CO_2 emission rates per hour of diesel engine idling have changed little in recent years. In the absence of more comprehensive studies, these emission factors are accepted as the best available. CO_2 emissions are most strongly affected by idle RPM, which this methodology addresses by including two different RPM levels to represent typical baseline idling for different daily low or high temperatures.
Emission factors (project)	Low	The eGRID emission factors used to estimate CO_2 emissions from generated electricity are based on extensive electric sector data collected by USEPA and the U.S. Department of Energy - Energy Information Administration.[23] While these emission factors do have some embedded uncertainties, this methodology does not require the Project Proponent to account for uncertainties in the eGRID emission factors. The methodology does require the Project Proponent to use the most specific eGRID emission factor available. If the PCA is known, the eGRID factor for this PCA must be used. Otherwise the emission factor for the eGRID subregion or State where the TSE facility is located (in declining order of preference) may be used. The eGRID factors do not enable consideration of the resource mix generating electricity (i.e. dispatch order) at

[23] See the eGRID 2012 Technical Support Document, included in the eGRID download at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html, for eGRID data sources and methodology. eGRID is developed from a variety of data collected by the U.S. Environmental Protection Agency (EPA), and the Energy Information Administration (EIA). Federal data sources include EPA, Clean Air Markets (EPA/CAMD) Annual and Ozone Season Emissions data (EPA, 2010); EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008; EIA, EIA-860: Annual Electric Generator Report (EIA, 2008a); EIA, EIA-861: Annual Electric Power Industry Report (EIA, 2008b); EIA, EIA-923 Schedule 3B: Power Plant Operations Report, Prime Mover Fuel Consumption (EIA, 2008c); EIA, EIA-923 Schedule 2: Power Plant Operations Report, Plant Cost and Quality of Fuel Receipts (EIA, 2008d); EIA, Electric Power Monthly, Plants Sold and Transferred (EIA, 2007-2010); and the North American Electric Reliability Corporation (NERC). Data displayed in eGRID are derived from the above data sources; EPA does not collect data directly from electric generators for eGRID. Inconsistencies between data sources, missing data, and ambiguous data occasionally necessitate adjustments to values of individual data elements. When necessary, EPA substitutes data from secondary sources or default values. EPA also updates ownership, corporate affiliation, and grid configuration data.

Data Parameter	Uncertainty Level of Data	QA/QC Procedures Risk Mitigation
		the time of day when TSE facilities are used. This would require tracking not just electricity consumption but also the time of day consumed, combined with time of day-specific emission factors accounting for which plants are dispatched at that time.

4.6.2 Uncertainty Deduction

The Project Proponent should address, in the GHG Project Plan, sources and magnitude of uncertainties relevant to both the baseline and with-project scenarios.

The *ACR Standard* requires that total uncertainty be no more than 10% of the mean estimated net emission reductions at 90% confidence. If the Project Proponent cannot meet the targeted ±10% of the mean at 90% confidence, then the reportable amount shall be the mean minus the lower bound of the 90% confidence interval.

Total uncertainty should be estimated by summing estimated baseline and project uncertainty:

$$UNC = \sqrt{\text{UNCERTAINTY}_{\text{BSL}}{}^2 + \text{UNCERTAINTY}_{\text{P}}{}^2} \quad \textbf{(9)}$$

Where:

UNC Total uncertainty for the TSE project; %

UNCERTAINTY_{BSL} Total uncertainty estimated for baseline scenario; %

UNCERTAINTY_{P} Total uncertainty estimated for project scenario; %

If *UNC* ≤ 10% of ER_{prelim}, then no deduction for uncertainty is required.

If *UNC* > 10% of ER_{prelim}, then the value of $ER_{project}$ shall be adjusted to account for uncertainty:

$$ER_{project} = ER_{prelim} * (1 - UNC) \quad \textbf{(10)}$$

Where:

$ER_{project}$ Net emission reductions across all TSE locations included in project, adjusted for uncertainty; metric tons CO_2

ER_{prelim} Preliminary calculation of net emission reductions across all TSE locations included in project, for the year, prior to accounting for uncertainty, as calculated in Equation (8); metric tons CO_2

UNC Total uncertainty for the TSE project; %. If *UNC* ≤ 10% of ER_{prelim}, set *UNC* = 0.

4.7 Calculation of ERTs

The Project Proponent shall include in the GHG Project Plan an *ex ante* estimation of Emission Reduction Tonnes (ERTs) over the duration of the approved Crediting Period. Actual ERT issuance will be based on *ex post* verified emission reductions.

$$ERT_t = \left(ER_{project,t_2} - ER_{project,t_1}\right) * \left(1 - BUF\right) \quad \textbf{(11)}$$

Where:

ERT_t Number of Emission Reduction Tonnes at time $t = t_2 - t_1$

$ER_{project,t2}$ Cumulative total net GHG emissions reductions up to time t_2, adjusted for uncertainty per Equation (10)

$ER_{project,t1}$ Cumulative total net GHG emissions reductions up to time t_1, adjusted for uncertainty per Equation (10)

BUF Percentage of project ERTs contributed to the ACR buffer pool; here BUF = 0 since emission reductions from avoidance of diesel idling are irreversible.[24]

Note that the calculation of ERTs accounts for uncertainty, but there are no required deductions for leakage (see Section 4.4) or non-permanence (see Section 6.4).

[24] Emission reductions achieved through the avoidance of fossil fuel combustion cannot be reversed subsequent to crediting. In contrast emission reductions achieved through some project types – e.g. forest carbon and other types of sequestration – can be reversed, for example through fire or harvest, and for that reason ACR requires these types of projects to mitigate reversal risk by depositing ERTs in a buffer pool or using other ACR-approved risk mitigation mechanisms. No buffer deduction is required for TSE projects since there is no reversal risk.

5. DATA COLLECTION AND MONITORING

It is critical for the accuracy and transparency of calculating, monitoring and verifying GHG reductions that:

- Measurements of operating hours and electricity consumption be undertaken with reliable equipment that is regularly calibrated;
- Average daily low and high temperatures be accurately recorded using data from the closest weather station (ASOS, MADIS, etc.);
- Multiple data cross-checks and internal validation be performed; and
- Measurement and calibration equipment and processes and changes thereto be clearly described as part of the CO_2 emissions reporting process.

5.1 Monitoring Plan Guidelines

A monitoring plan is a working document that describes procedures for collecting activity data, baseline and project emissions data, and for ensuring and controlling the quality of the collected data. The TSE project monitoring plan will be updated whenever the methodologies used to measure project activity or baseline emissions are changed.

Some of the key GHG accounting principles that should drive the design of data collection and monitoring include:[25]

- *Relevance*: levels of accuracy and uncertainty associated with monitoring methods should reflect the intended use of the data and the objectives of the offset project. Some intended uses may require greater accuracy than others.
- *Accuracy*: measurements, estimates, and calculations should be unbiased, and uncertainties reduced as far as practical. Calculations and measurements should be conducted in a manner that minimizes uncertainty.
- *Conservativeness*: where there are uncertainties in monitored data, values used to quantify GHG reductions should err on the side of underestimating rather than overestimating reductions.

5.2 Data Measurements

Implementation of the quantification methodology described in section 4 requires measurement of the following activity data:

- Operating hours of the TSE systems (equal to hours of diesel idling avoided)
- Electricity consumption of the TSE systems and any office buildings

[25] Based on World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), *GHG Protocol for Project Accounting*, November 2005 and International Organization for Standardization ISO) 14064-2:2006(E) - Greenhouse gases. Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements.

- Average daily low and high temperatures (for the temperature-adjusted baseline emissions model), based on data from approved sources (ASOS, MADIS or certified PWS)

Records of all data shall be recorded and archived electronically in a database maintained by the Project Proponent. Data aggregations of hourly, daily, and annual data totals should be available by querying the database. All database reports and calculations to support the CO_2 emission reduction estimates must be archived to facilitate *ex post* verification.

Table 6 lists the key data and parameters to be monitored and recorded for the purposes of capturing activity data, calculating emission reductions, conducting internal cross-checking, and providing data for third-party validation and verification. All project data should be stored electronically and centrally in a format that is easily accessible for validation and verification.

Table 6. Parameters for Monitoring and Emission Reduction Calculations

Parameter	Unit	Description	Source of data	Used in equations	Monitoring frequency	Proportion of data monitored
Number of TSE facilities included in project	#	Total TSE facilities included in the GHG project boundary	Project Proponent records	-	Once per Crediting Period	100%
Number of TSE spots per facility / per total project	#	Total TSE parking spots included in the GHG project boundary	Project Proponent records	-	Once per Crediting Period	100%
Locations of TSE facilities	Loca-tions	Geographic location (by zip code) of each TSE facility included in the project, necessary to determine average daily low and high temperatures (baseline emissions calculation) and appropriate eGRID emission factor (project emissions calculation)	Project Proponent records	-	Once per Crediting Period	100%

Parameter	Unit	Description	Source of data	Used in equations	Monitoring frequency	Proportion of data monitored
Operating hours for each TSE system spot	Hours	Hours of operation, by day, for each TSE system spot at each included facility, necessary for calculating hours of avoided idling (baseline emissions calculation)	Project Proponent records	1, 2	Continuous	100%
Daily low and high temperatures	^{o}F	Low and high temperatures for each day	Weather data from ASOS, MADIS, or certified PWS	1, 2	Measured daily,	100%
Electricity consump-tion of the TSE systems and office buildings	kWh	Electricity consumed by TSE systems included in the project boundary, necessary for calculating emissions from generation of electricity consumed by TSE systems (project emissions calculation)	Project Proponent records / electric distribution company bills	5	Continuous	100%

5.3 Quality Assurance/Quality Control (QA/QC) Measures

The Project Proponent should maintain a QA/QC program including measures such as:

- Accurate metering and cross-checks: TSE system usage measured by visit duration hours (from operations data collection), and by the quantity sold (or billable hours, from financial/revenue transactions). These two independent measures of activity should be reviewed and updated, as necessary, as well as used as a cross-check against each other.
- Calibrations on key monitoring instrumentation are made at least annually, and more frequently if any QA/QC issues are indicated.
- Responsible entities: field personnel and corporate data system manager shall be responsible for data capture, to ensure data are properly recorded into the database.
- A designated corporate QA/QC officer shall be responsible for the following:

- Development, implementation, and oversight of QA/QC procedures for measurement, calibration, and data collection of CO_2-related data;
- Assess calculation results to ensure data have been properly processed; and
- Strategies for identifying and managing missing or poor-quality data, and making any necessary adjustments to data based on findings from the QA/QC measures.

- Daily log sheets, calibration and maintenance records, 3rd party analytical results, utility bills/receipts, and other electronic and hard copy data records shall be archived for a minimum of three (3) years to support future auditing and verification activities.
- Emission reduction estimates shall be made so as to overstate project emissions and understate baseline emissions, thereby erring on the side of understating net GHG emission reductions.

5.4 Validation and Verification Interval

Per the *ACR Standard*, validation of the GHG Project Plan will occur once per Crediting Period.

Verification of GHG assertions is at the discretion of the Project Proponent, provided it conforms to ACR requirements. Verification must occur prior to any new issuance of ERTs. ERTs may be created and issued annually, or at the Proponent's request, more or less frequently. At each request for issuance of new ERTs, the Project Proponent must submit a verification statement from an approved verifier based on a desk audit. No less than once every five years, Proponents must submit a verification statement based on a full verification including a field visit and an adequate sample of the TSE facilities included in the TSE project, as determined in the verifier's professional judgment, necessary for the verifier to provide a reasonable level of assurance that the GHG assertion is without material discrepancy.[26]

[26] Reasonable level of assurance, and materiality, are defined in the *ACR Standard* and *ACR Validation/Verification Guideline for GHG Projects*.

6. EMISSIONS OWNERSHIP AND QUALITY

6.1 Real

TSE project emission reductions should represent a recognizable action that directly resulted in reductions of anthropogenic CO_2 emissions, which would have been released to the atmosphere in the absence of the TSE project. Emission reductions must be demonstrated to have actually taken place and to be attributable to TSE use, as monitored using a comprehensive data collection, storage, and management system.

Emission reductions must have occurred and been verified prior to ERT issuance. ACR will not forward issue nor forward register a projected stream of future offsets.

6.2 Surplus

Emission reductions are surplus if they are not required by law. While several states have enacted anti-idling regulations with the goal of reducing criteria pollutant (NOx, CO, PM, VOC) emissions, no state or federal laws require truck drivers or fleets to reduce GHG emissions.

Substantial problems with compliance and enforcement have occurred in every area that has enacted an anti-idling regulation. Because of these concerns, the majority of state environmental agencies – as well as their respective EPA Regional Offices – are not convinced these regulations create real emission reductions, and have not incorporated these emission reductions in their State Implementation Plans (SIPs). Among the jurisdictions that do not claim these emission reductions within the state SIP are the states of New York, Pennsylvania, Arizona, Nevada, and New Hampshire, as well as the cities of Denver, Colorado; Washington, D.C.; St. Louis, Missouri; and Philadelphia, Pennsylvania.

There are also several jurisdictions that have made provisions for incorporating idling emission reductions within the SIP, but have specifically exempted long-haul trucks with sleepers. These jurisdictions include the states of California, Arizona, and Illinois, and Salt Lake City, Utah. Since California's anti-idling regulation (implemented January 2005) exempts sleeper trucks at travel centers, it does not affect TSE emission reductions. It should be pointed out that this regulation was developed to reduce airborne toxics and was not intended to regulate GHG emissions.

Only the emission reductions from TSE sites located within areas where there are no anti-idling regulations, where the anti-idling regulations include provisions specifically exempting long-haul trucks with sleepers, or where the Project Proponent presents evidence suitable to the validator/verifier that anti-idling regulations are routinely not enforced, are eligible for crediting under this methodology. See section 3.2.2 for a description of how routine non-enforcement may be documented and demonstrated to a validator/verifier.

6.3 Unique

Emission reduction accounting must ensure that there is no double counting, double crediting or double selling. The Project Proponent's accounting system must record each visit, TSE system use, and track

this usage by driver, fleet, parking space, facility, city, and state. Any double counting in systems use and emissions reduction calculations can thus readily be identified.

ERTs registered on ACR will be issued unique serial numbers that link the verified emission reduction to a specific project or source, geographic identifier, and vintage year, guarding against the possibility of multiple sales. This also provides the ability to track all transfers, trades, retirements or cancellations of ERTs. Market participants can track individual emission reductions from cradle to grave using the on-line transaction log.

6.4 Permanent

The CO_2 emission reductions from avoided diesel idling are irreversible because the emissions are avoided from trucks not idling, and which would have idled in the absence of the TSE project. Once the TSE system has operated and the truck has not idled, the emission reduction has occurred and cannot reversed subsequent to crediting.

6.5 Verifiable

The data sources used to create the ERTs claimed in any GHG assertion must be readily verifiable by a competent independent third party validation/verification body. Measurement data records and electricity consumption data shall be maintained by the Project Proponent and be readily available for audit. The Project Proponent shall maintain its own QA/QC system and internal cross-checks to identify, diagnose and correct for any apparent data anomalies. The Project Proponent's data system shall record fine-grained data about locations (parking space, facility, city, county, state), visits (e.g., date and time of the start and end of each session), and drivers. This information shall be maintained in a database format that is routinely evaluated for programming errors and data anomalies. Data audits should be readily supported.

6.6 Direct Emission Reductions

The emission reductions from a TSE project will represent direct emissions reduced by the project activity (through the avoidance of diesel engine idling) at clearly identified and controlled sources. None of the emission reductions claimed by the project will be indirect emission reductions.

The Project Proponent shall include in its Annual Attestation that all emission reductions are direct reductions.

6.7 Ownership of GHG Reductions

The emissions from diesel engines are “owned” by the owner/operators of the trucks, unless signed over contractually to another party. These owner/operators must sign over to the Project Proponent all rights to the environmental attributes, including GHG reductions, inherent in their use of the Project Proponent's TSE facilities. The Project Proponent should provide to ACR a sample agreement with participating truckers indicating they have relinquished ownership of the GHG reductions to the Project Proponent.

Other entities with a potential or hypothetical claim on GHG reductions could include:

- *Travel centers hosting the TSE facilities*. Travel centers will generally own the real estate on which TSE systems are deployed, but do not contribute either technology or investment toward the achievement of TSE emission reductions. Travel centers may receive a percentage of the TSE operator's gross receipts as their inducement to allow the TSE operator to install systems. If the travel center operator has signed an agreement conferring rights to GHG emission reductions to the Project Proponent as lessee, the Project Proponent should provide such sample agreement to ACR.
- *Granting agencies*. In certain instances, the TSE operator's ownership of CO_2 emission credits has been, or may in the future be, limited by regulations established by federal or state agencies that provided funding to finance a portion of the TSE system installation costs. Granting federal agencies could potentially have a claim on carbon dioxide reductions that could limit the TSE operator's right to sell ERTs. The focus of these funding agencies (primarily the U.S. EPA and the U.S. Department of Transportation) is on the reduction of criteria pollutant emissions. These funding programs generally make no provisions concerning greenhouse gases, nor do they generally prohibit the TSE operator from selling NOx and VOC reductions.
- *State agencies*. Individual states may have their own criteria that can affect either emission credit ownership, or the extent to which such emission credits may be sold. If state mandates (and/or state funding programs) are directed toward criteria pollutant or particulate matter reductions, but do not address GHG emission reductions, the Project Proponent may argue that GHG emission reduction ownership is unaffected by these mandates.

The Project Proponent shall address in the GHG Project Plan any potential conflicting claims, and if necessary provide supporting evidence that they have title or contractual rights to the claimed emission reductions and that no other entity has a conflicting claim, prior to ACR registration. In addition, Project Proponents shall review available material from the users of TSE systems (both fleets and their owners) to ensure that none are claiming reductions in their own carbon footprint from the use of TSE systems. If such claims are made, the Project Proponent shall request the truck fleets or their owners remove such claims from public materials, whether a website, sustainability report or other publication. In addition Project Proponents shall review available material from state or local government to ensure that public agencies are not claiming reductions from the use of TSE systems within their territories. If such claims are made, the Project Proponent shall request these agencies have such claims removed from public materials, whether a website, sustainability report or other publication.

6.8 Community and Environmental Impacts

Per the *ACR Standard*, community and environmental impacts must be net positive overall. Project Proponents shall document in the GHG Project Plan a mitigation plan for any foreseen negative community or environmental impacts, and shall disclose in their Annual Attestations any negative environmental or community impacts or claims by community members of negative environmental and community impacts.

TSE projects may not have significant community and environmental impacts. If there are any significant impacts from the TSE installation and/or operation, Project Proponents should take into account ACR's Community and Environmental Impacts criteria when applying this methodology to

specific projects. These criteria require analysis of any adverse environmental or social impacts on the communities affected by a project. If there are any adverse impacts that may result from the project, Project Proponents should conduct stakeholder meetings with community groups or other appropriate stakeholders to ensure that any concerns associated with the project are addressed.

TSE projects will however cause positive environmental co-benefits in the form of reductions in criteria pollutant emissions (e.g., NOx, PM, CO, and VOC), as well as environmental/community benefits such as noise reduction, job creation, etc. The Project Proponent is encouraged to quantify such benefits in the GHG Project Plan and consider additional optional certifications.

6.9 Warranties

The Project Proponent shall include in the GHG Project Plan the following warranty:

"I hereby warrant that all information provided by [Project Proponent] in this GHG Project Plan is true and factual, and all matters affecting the validity of this GHG Project Plan or consequent emission reduction credit claims have been fully disclosed. This project has not been previously registered with any other emission reduction program or regulatory agency. [Project Proponent] has title to the GHG emission reductions created by this project, and warrants that no security has been granted over those rights, and said rights are valid. Any ERT delivery risks associated with lack of statutory rights, governmental agency recognition, or future emission reduction creation operations commensurate with potential ERT forward option volumes will be mitigated by [Project Proponent] via clearing house, registry, and/or insurance instruments, as appropriate."

6.10 Annual Attestations

The Project Proponent shall submit Annual Attestations, as required in the *ACR Standard*, in a format to be provided by ACR. The Annual Attestations address continued undisputed ownership of emission reductions, any claims of negative environmental or community impacts, and a mitigation plan in the case of such claims.

7. APPENDIX A: WORKED EXAMPLE FOR CALCULATING EMISSION REDUCTIONS

In this worked example of the emission calculations in Chapter 4, we calculate baseline and project emissions, net GHG reductions, and *ex ante* estimated ERTs for a hypothetical TSE facility located in Dallas, Texas. The TSE project is assumed to include only this one TSE facility.

1. Activity data

Assume the following monthly average low temperatures, TSE usage hours, and electricity consumption at the Dallas TSE facility:

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average low temp (^{o}F)	36	41	49	56	65	73	77	76	69	58	47	39
TSE usage hours at location	20,299	18,723	18,529	20,270	23,089	25,020	29,960	30,772	24,184	22,877	18,739	16,901
Electricity consumption (kWh)	30,449	28,085	27,794	30,405	34,634	37,530	44,940	46,158	36,276	34,316	28,109	25,352

2. Baseline emissions

For January, February, March, June, July, August, November, and December, average temperatures are either below 50^{o}F or above 70 ^{o}F, so we assume truckers would be idling at the 1,000-1,200 RPM level to power both climate control equipment and electrical accessories. We use Equation (1). For example for January: (NOTE: calculations will be made by day, but for simplicity, we are using monthly temperatures in this example)

$BE_{dayX,locY}$ = (11,349 gCO_2/hour * 20,299 hours) / 1,000,000 = 230.4 metric tons CO_2

For April, May, September, and October, average temperatures are between 50^{o}F and 70 ^{o}F, so we assume truckers would be idling at the 600-800 RPM level to power electrical accessories only. We use Equation (2). For example for April:

$BE_{dayX,locY}$ = (4,934 gCO_2/hour *20,270 hours) / 1,000,000 = 100.01 metric tons CO_2

Repeating this calculation for each month yields:

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Emission factor (gCO2/hr)	11,349	11,349	11,349	4,934	4,934	11,349	11,349	11,349	4,934	4,934	11,349	11,349
Baseline emissions for month (metric tons CO2)	230.4	212.5	210.3	100.0	113.9	284.0	340.0	349.2	119.3	112.9	212.7	191.8

Summing across months using Equation (3) gives a total of 2,477 metric tons CO_2. Because there is only one TSE facility in this hypothetical project, 2,477 metric tons CO_2 is the total baseline emissions for the year, assuming an AILEF index of zero (i.e. no anti-idling regulation, or zero enforcement of anti-idling regulations).

3. Project emissions

Imagine the power control area (PCA) is not known, but the TSE facility location (Dallas) clearly places the project in eGRID subregion ERCT. Having downloaded the eGRID2012 Version 1.0 files, we go to the **SRL09** tab, look up ERCT at the left, and scroll across to find the **eGRID subregion annual CO_2 total output emission rate** for ERCT is 1,181.73 lb/MWh. This will be the emission factor used for electricity generation. (NOTE: calculations will be made by day, but for simplicity, we are using monthly temperatures in this example)

For January, applying Equation (5) yields:

$PE_{dayX,locY}$ = (30,449 kWh / 1,000) * (1,181.73 lb/MWh / 2,205 lbs per metric ton) = 16.3 metric tons CO_2

Repeating this calculation for each month yields:

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Emission factor (lb/MWh)	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73	1,181.73
Baseline emissions for month (metric tons CO2)	16.3	15.1	14.9	16.3	18.6	20.1	24.1	24.7	19.4	18.4	15.1	13.6

Summing across months using Equation (6) gives a total of 216.5 metric tons CO_2. Because there is only one TSE facility in this hypothetical project, 216.5 metric tons CO_2 is the total project emissions for the year.

4. Emission reductions

Applying Equation (8), and considering that leakage is assumed to be zero,

$ER_{prelim} = (BE_{project} - PE_{project}) * (1 - LK)$

= (2,477 – 216.5) * (1 – 0)

= 2,260.4 metric tons CO_2

5. Uncertainty deduction

Assume that total uncertainty, when estimated and aggregated across the baseline and project scenarios, is less than 10% of ER_{prelim}. Therefore no deduction for uncertainty is required. Equation (10) is not used and $ER_{project}$ is the same as ER_{prelim}.

6. Calculation of ERTs

Assume this is the first year of the project so there are no prior t_1 cumulative emission reductions to subtract. *BUF* is set to zero since the emission reductions are irreversible. Applying Equation (11),

$$ERT_t = \left(ER_{project_{t_2}} - ER_{project_{t_1}}\right) * \left(1 - BUF\right)$$

= (2,260.4 – 0) * (1 – 0)

= 2,260.4

2,260 metric tons CO_2 are the ERTs projected *ex ante* to be registered for the first year of the project, once verified by an approved third party verifier.

8. APPENDIX B: EGRID SUBREGIONS AND EMISSION RATES

The following map and table show the eGRID subregions and GHG emission rates, used in section 4.3 to calculate CO_2 emissions from TSE use. Note these eGRID subregion rates may only be used in the case that the Power Control Area is not known. See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

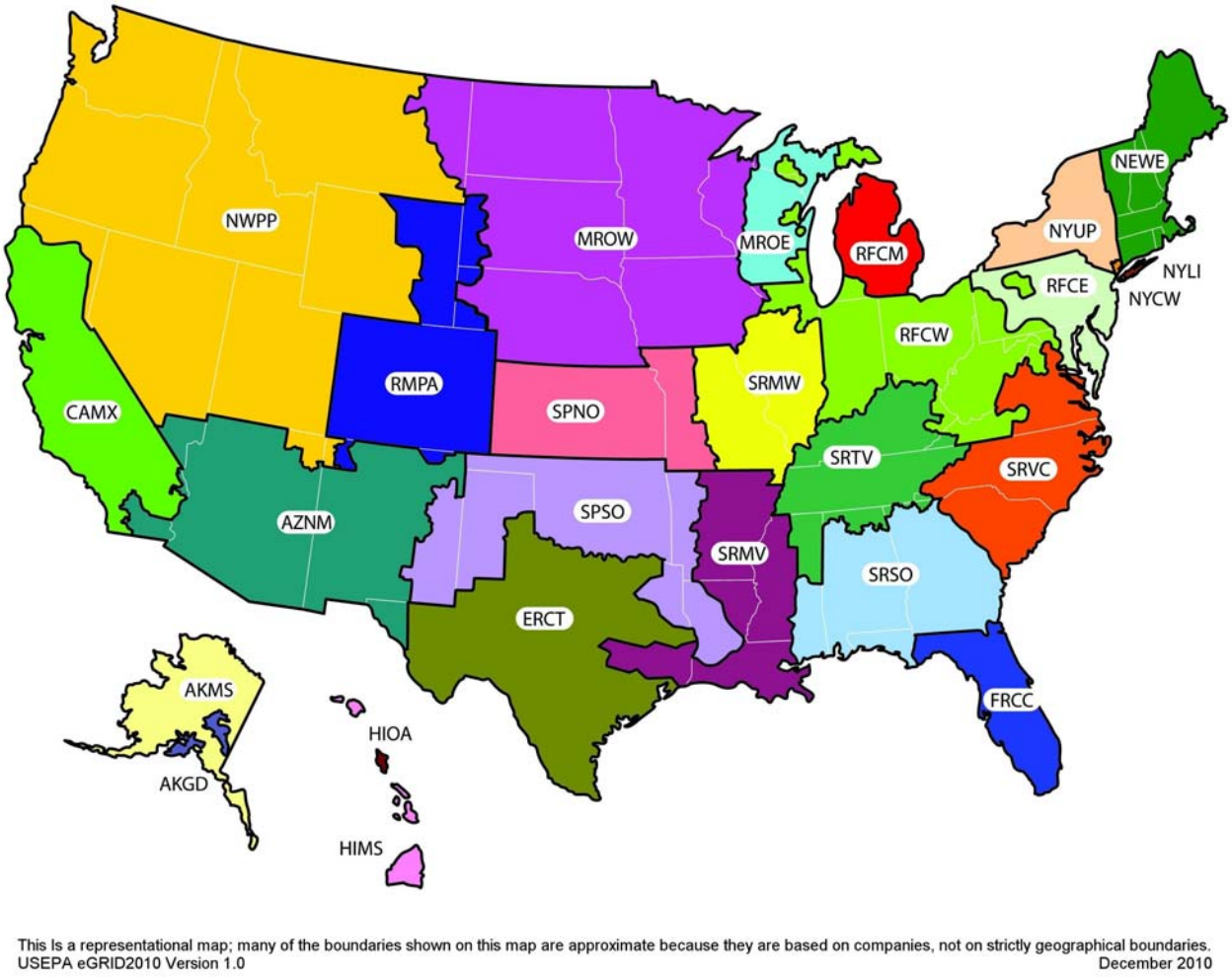


Figure AB-1. eGRID subregions.

Table AB-1. Annual GHG output emission rates for 2009 from eGRID2012 v1.0.

eGRID subregion acronym	eGRID subregion name	Annual total output emission rates			Annual non-baseload output emission rates		
		Carbon dioxide (CO_2) (lb/MWh)	Methane (CH_4) (lb/GWh)	Nitrous oxide (N_2O) (lb/GWh)	Carbon dioxide (CO_2) (lb/MWh)	Methane (CH_4) (lb/GWh)	Nitrous oxide (N_2O) (lb/GWh)
AKGD	ASCC Alaska Grid	1,280.86	27.74	7.69	1,320.75	33.16	6.34
AKMS	ASCC Miscellaneous	521.26	21.78	4.28	1,469.44	61.53	12.10
AZNM	WECC Southwest	1,191.35	19.13	15.56	1,187.67	22.25	9.12
CAMX	WECC California	658.68	28.94	6.17	993.89	33.52	4.07
ERCT	ERCOT All	1,181.73	16.70	13.10	1,155.44	19.66	7.59
FRCC	FRCC All	1,176.61	39.24	13.53	1,301.40	36.04	11.91
HIMS	HICC Miscellaneous	1,351.66	72.40	13.80	1,615.98	91.06	17.19
HIOA	HICC Oahu	1,593.35	101.74	21.96	1,621.42	107.94	18.73
MROE	MRO East	1,591.65	23.98	27.04	1,868.23	29.40	30.40
MROW	MRO West	1,628.60	28.80	27.79	2,114.93	61.83	37.41
NEWE	NPCC New England	728.41	75.68	13.86	1,157.44	61.72	14.43
NWPP	WECC Northwest	819.21	15.29	12.50	1,404.55	38.56	18.79
NYCW	NPCC NYC/Westchester	610.67	23.75	2.81	1,118.06	22.47	2.31
NYLI	NPCC Long Island	1,347.99	96.86	12.37	1,336.59	30.78	3.51
NYUP	NPCC Upstate NY	497.92	15.94	6.77	1,347.12	41.08	16.87
RFCE	RFC East	947.42	26.84	14.96	1,628.97	32.94	22.46
RFCM	RFC Michigan	1,659.46	31.41	27.89	1,834.66	35.17	29.15
RFCW	RFC West	1,520.59	18.12	25.13	2,001.76	24.56	32.10
RMPA	WECC Rockies	1,824.51	22.25	27.19	1,756.62	23.54	22.51
SPNO	SPP North	1,815.76	21.01	28.89	2,147.53	26.32	31.82
SPSO	SPP South	1,599.02	23.25	21.79	1,513.73	25.22	15.11
SRMV	SERC Mississippi Valley	1,002.41	19.45	10.65	1,201.66	25.72	7.11
SRMW	SERC Midwest	1,749.75	19.57	28.98	2,192.85	25.04	35.89
SRSO	SERC South	1,325.68	22.27	20.78	1,622.00	27.22	23.50
SRTV	SERC Tennessee Valley	1,357.71	17.28	22.09	1,921.12	25.16	30.61
SRVC	SERC Virginia/Carolina	1,035.87	21.51	17.45	1,677.35	38.55	25.56
U.S.		**1,216.18**	**24.03**	**18.08**	**1,555.48**	**30.83**	**19.76**

American Carbon Registry
AT WINROCK INTERNATIONAL

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ACKNOWLEDGEMENTS

This methodology was developed by:

Dentons, U.S., LLC

EOS Climate

In cooperation with:

Susan Wood Consulting

True Manufacturing

ACRONYMS AND DEFINITIONS

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry (ACR) Standard apply.

TERM	ACRONYM (if applicable)	DEFINITION
Ammonia	NH_3	A chemical compound composed of nitrogen and hydrogen. Can be used as a low-GWP refrigerant.
Advanced refrigeration system		A refrigeration system deploying advanced technology that uses low-GWP refrigerants instead of CFCs, HCFCs, or HFCs as a refrigerant.
Carbon Dioxide	CO_2	A chemical compound composed of two oxygen atoms and a single carbon atom. Can be used as a low-GWP refrigerant.
Carbon dioxide equivalent	CO_2e	A standard unit of measure to express the impact of each different greenhouse gas in terms of the amount of CO_2 that would create the same amount of global warming.
Carbon offset credits	Offsets	A carbon offset is a reduction in emissions of carbon dioxide or greenhouse gases made in order to compensate for or to offset an emission made elsewhere.
Cascade Refrigeration System		Similar to a secondary refrigeration system, a cascade system employs dual cycles, and utilizes a heat exchanger and two types of refrigerants. This enables the system to achieve colder temperatures that may not be

TERM	ACRONYM (if applicable)	DEFINITION
		achievable through primary or secondary refrigerant systems.
Chlorofluorocarbon	CFC	A class of compounds of carbon, hydrogen, chlorine, and fluorine that are commonly used as refrigerants.
End-of-Life	EOL	Emissions resulting from the disposal of refrigeration products and refrigerant.
GHG Source, Sink, or Reservoir	SSR	• GHG Source – Physical unit or process that releases a GHG into the atmosphere • GHG Sink – Physical unit or process that removes a GHG from the atmosphere • GHG Reservoir - Physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store or accumulate a GHG removed from the atmosphere by a GHG sink or captured from a GHG source.
Global warming potential	GWP	An index that attempts to integrate the overall climate impacts of a specific action (e.g., emissions of CH_4, NO_x or aerosols). It relates the impact of emissions of a gas to that of emission of an equivalent mass of CO_2.
Hydrocarbon	HC	A class of compounds containing only hydrogens and carbons (e.g. propane, isobutene, propylene). Certain HCs can be used as low-GWP refrigerants.

TERM	ACRONYM (if applicable)	DEFINITION
Hydrochlorofluorocarbon	HCFC	A class of compounds of carbon, hydrogen, chlorine, and fluorine that are commonly used as refrigerants.
Hydrofluorocarbon	HFC	A class of compounds that contain carbon, fluorine, and hydrogen that are commonly used as refrigerants, as well as solvents, aerosol propellants, and foam blowing agents.
Hydrofluoroolefins	HFO	A class of compounds composed of hydrogen, fluorine, and carbon. This class of compounds can be used as low-GWP refrigerants. Some HFO refrigerants are comprised of a mix of HFOs, referred to as an HFO blend.
HFC Refrigerant		Refrigerant comprised of either a mix of hydrofluorocarbons (HFCs) referred to as an “HFC blend”, or a single HFC.
Large Commercial Refrigeration		Equipment used to store and display chilled and frozen goods for commercial sale such as in food retailers, supermarkets, convenience stores, bakeries, and restaurants. For the purposes of this methodology, this includes commercial refrigeration units with an initial charge of 50 lbs or more of refrigerant.
Low-GWP		For the purposes of this methodology, a GWP <15 is considered low-GWP.
Project activity		Projects that avoid the emissions of CFC, HCFC, or HFC gases through the

TERM	ACRONYM (if applicable)	DEFINITION
		deployment of an advanced refrigeration system using a SNAP approved low-GWP refrigerant in Large Commercial Refrigeration or Stand-alone Commercial Refrigeration systems. See Applicability Conditions in Section 1.2.
Project Start Date		The date that the advanced refrigeration system(s) became operational and, therefore began to reduce GHG emissions against the baseline.
Refrigeration equipment		An Appliance[1], or component parts of a system, that uses refrigerant to provide cooling under controlled conditions.
Secondary Loop Refrigeration System		An advanced refrigeration system where a heat transfer medium (e.g. glycol) is used in conjunction with a primary refrigerant.
Significant New Alternative Policy	SNAP	The U.S. Environmental Protection Agency's (EPA) SNAP program implements section 612 of the amended Clean Air Act of 1990, which requires EPA's continuous review of alternatives to find those that pose less overall risk to human health and the environment. Through these evaluations, SNAP generates lists of acceptable and unacceptable substitutes for each of the major industrial use sectors. The intended effect of the SNAP program is to promote a smooth transition to safer alternatives.

[1] Per 40 CFR §82.3, an "Appliance" is defined as "any device which contains and uses a refrigerant, and which is used for household or commercial purposes, including, without limitation, any refrigerator, chiller, or freezer."

TERM	ACRONYM (if applicable)	DEFINITION
Stand Alone Commercial Refrigeration		Refrigerators, freezers, reach-in coolers (either open or with doors), and refrigerated food processing and dispensing equipment where all refrigeration components are integrated, and, for the smallest types, the refrigeration circuit is entirely brazed or welded. These systems are fully charged with refrigerant at the factory and typically require only an electricity supply to begin operation.

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1 BACKGROUND AND APPLICABILITY

1.1 SUMMARY DESCRIPTION OF THE METHODOLOGY

Modern society is dependent on refrigeration to process, store and transport food, as well as on air conditioning in the built environment and motor vehicles. Reliable and cost-effective cooling is also critical for other commercial and industrial processes, such as in pharmaceutical and chemical production, oil refining, aerospace and defense technologies, data servers, and ice rinks. These diverse applications typically rely on refrigerants, the chemical coolants that can reach low temperatures and transfer heat by undergoing a phase change between liquid and gas (through condensation).

Up until the mid-1990s, chlorofluorocarbons (CFCs) were in widespread use as refrigerants. CFCs destroy the Earth's protective ozone layer and are also powerful greenhouse gases (GHGs). Under the Montreal Protocol and United States Clean Air Act, nearly all CFC production ended in the United States in 1996.[2] As a result, many applications transitioned to using hydrochlorofluorocarbon (HCFC) refrigerants, which also contribute to ozone depletion and climate change, although to a lesser extent than CFCs. With the phase out of HCFCs currently underway, the most commonly used refrigerants today are hydrofluorocarbons (HFCs). HFCs, while safe for the ozone layer, are also powerful GHGs when released to the atmosphere.

Across the various refrigeration and air conditioning applications, there are a number of approaches that can be used to reduce GHG emissions from both new and installed equipment. This Methodology focuses on reductions from new equipment, as described below.

For limited applications, some businesses are using alternatives to HFC refrigerants with little or no global warming potential (GWP) as they manufacture and install new refrigeration systems. These alternatives include hydrocarbons, ammonia, carbon dioxide, and hydrofluoroolefins (HFOs). In some advanced commercial refrigeration systems, these alternatives completely replace the use of HFC refrigerants, while in other advanced systems these alternatives are used in combination with HFCs. For example, secondary loop and cascade refrigeration systems used in supermarkets often use HFC refrigerants in combination with refrigerants that

[2] After 1996, the Montreal Protocol authorized limited production of CFCs for "essential uses" as propellants in medical devices (metered dose inhalers relied upon by asthmatics) and for laboratory and analytical uses. Production for essential medical uses ended in the U.S. on January 1, 2012. The exemption for de minimis CFC production essential laboratory and analytical uses remains in effect.

have lower GWPs (such as carbon dioxide) or heat transfer medium (such as glycol). These types of systems are eligible under this Methodology.

Table 1: Eligible Refrigerant Sectors and Segments[3]

Segment	ELIGIBLE SEGMENTS IN SECTOR
Large Commercial Refrigeration	Equipment used to store and display chilled and frozen goods for commercial sale such as in supermarkets, convenience stores, bakeries, and restaurants. For the purposes of this methodology, this includes commercial refrigeration units with an initial charge of 50 lbs or more of refrigerant.
Stand-Alone Commercial Refrigeration	Refrigerators, freezers, reach-in coolers (either open or with doors), and refrigerated food processing and dispensing equipment where all refrigeration components are integrated, and, for the smallest types, the refrigeration circuit is entirely brazed or welded. These systems are fully charged with refrigerant at the factory and typically require only an electricity supply to begin operation.

This Methodology provides the quantification framework for the creation of carbon offset credits from the reductions in GHG emissions resulting from transitioning to advanced refrigeration systems in the eligible sectors. The Methodology is intended to be used as an incentive within the relevant industries to increase these activities.

This Methodology is based on a robust data set, including the United Nations Environment Programme Technical Options Committee for Refrigeration, Air Conditioning and Heat Pumps, the United States EPA Vintaging Model, the 2016 ICF Accounting Tool to Support Federal Reporting of Hydrofluorocarbon Emissions, the United States EPA GreenChill Partnership, and the 2006 International Panel on Climate Change Guidelines for Greenhouse Gas Inventories.

1.2 APPLICABILITY CONDITIONS

For the purposes of this Methodology, projects that avoid the emissions of CFC, HCFC, or HFC gases in the following activity are considered a “project activity”:

[3] For a general discussion of advanced refrigeration systems, see the United States EPA discussion here: http://www2.epa.gov/greenchill/advanced-refrigeration

- Deployment of an advanced refrigeration system using a SNAP-approved low-GWP refrigerant in Large Commercial Refrigeration or Stand-alone Commercial Refrigeration systems.

For purposes of this Methodology, a project activity may comprise of (i) the complete replacement of CFC, HCFC or HFC-based equipment (including all components) with an advanced refrigeration system at an existing facility, (ii) the installation of an advanced refrigeration system as a new and additional system at an existing facility, or (iii) the installation of an advanced refrigeration system in new construction.

In addition to satisfying the latest ACR program eligibility requirements as found in the ACR Standard, project activities must satisfy the following conditions for this Methodology to be applicable:

I. The project is located in North America.
II. The project is within a sector and segment which has a low adoption rate for the relevant project activity ("Eligible Project Activity" & "Eligible Refrigerant Sector/Segment" (see Table 1)).
III. For a project activity that involves replacement of CFC, HCFC, or HFC-based equipment with an advanced refrigeration system where the original equipment is decommissioned, any CFCs or HCFCs in the original equipment must be recovered and destroyed in accordance with ACR or the California Air Resource Board ODS Destruction Methodology and any HFCs must be managed in accordance with EPA regulations (40 CFR Part 82, Subpart F) under Section 608 of the Clean Air Act[4].
IV. Any refrigerant used in the advanced refrigeration system must be an acceptable substitute according to United States EPA Significant New Alternatives Policy (SNAP) program for use in commercial refrigeration end-uses and be used in accordance with SNAP use conditions.[5]

1.3 REPORTING PERIODS

- A project shall have one reporting period that shall not exceed more than 12 months in length.
- The Reporting Period begins on the Project Start Date.

[4] EPA regulations (40 CFR Part 82, Subpart F) under Section 608 of the Clean Air Act restrict the resale of used ozone depleting and HFC refrigerant to a new owner unless it has been reclaimed by an EPA-certified refrigerant re-claimer. Refrigerant that has been recovered and/or recycled can be returned to the same system or other systems owned by the same person without being reclaimed.
[5] http://www.epa.gov/ozone/snap/refrigerants/index.html

1.4 CREDITING PERIOD

A Crediting Period is the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. The crediting period for all project activities shall be ten years. The crediting period begins on the Project Start Date.

1.5 PERIODIC REVIEWS AND REVISIONS

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project's activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the Methodology.

2 PROJECT BOUNDARIES

2.1 GEOGRAPHIC BOUNDARY

The project boundary, depicted by the figure below, includes the physical and geographical site where the advanced refrigerant system is installed, as well as the locations involved in disposal of the older technology, including management of any previously used HFC or destruction of the CFC or HCFC refrigerant in the older system that is replaced.

Figure 1: Project Boundary Diagram for Advanced Refrigeration Systems

The GHG emission sources included within the project boundary are depicted in the dark blue boxes in Figure 1. They include emissions from the operation of the refrigeration equipment, emissions resulting from the recharging and servicing of that equipment, and end-of-life (EOL) / disposal emissions. Table 2 lists the GHG sources included and excluded depending on whether the sources are inside or outside project boundaries.

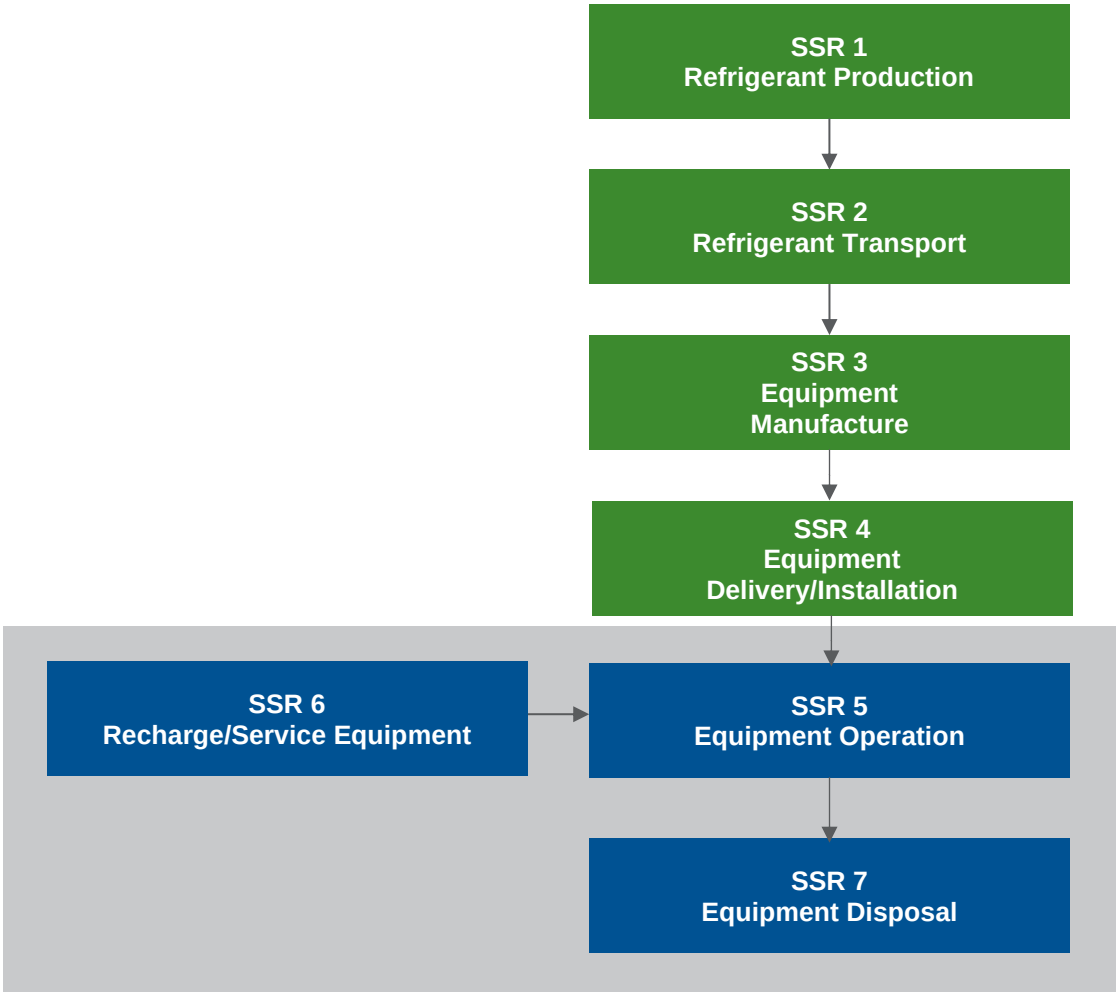


Table 2: Greenhouse Gases and Sources

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFICATION METHOD
1 Refrigerant Production	Fossil fuel emissions from the production of refrigerants	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	Refrigerant leaks during production	HFC	E	N/A
		Low GWP Refrigerant	E	N/A
2 Refrigerant Transport	Fossil fuel emissions from transport of refrigerants	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	Refrigerant leaks during transport	HFC	E	N/A
		Low GWP refrigerant	E	N/A
3 Equipment Manufacture	Fossil fuel emissions from the operation of the refrigeration system in the baseline and the project.	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
4 Equipment Delivery and Installation	Fossil fuel emissions from the delivery and installation of the advanced refrigeration system.	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
5 Equipment Operation	Fossil fuel emissions from the operation of the refrigeration system in	CO_2	E	N/A
		CH_4	E	N/A

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFICATION METHOD
	the baseline and the project.	N_2O	E	N/A
	Refrigerant leaks from the operation of the refrigeration system in the baseline and the project.	CFC	I	See Table 4
		HCFC	I	See Table 4
		HFC	I	See Table 4
		Low GWP refrigerant	I	See Table 4
6 Equipment Service/ Recharges	Fossil fuel emissions from servicing refrigeration or A/C equipment or system to replace leaked refrigerant	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	Refrigerant emissions occurring from servicing refrigeration or A/C equipment or system to replace leaked refrigerant	HFC	I	See Table 4
		Low GWP Refrigerant	I	See Table 4
7 EOL/ Equipment Disposal	Emissions from the disposal of the equipment at end-of-life (EOL), including destruction of refrigerant.	CO_2	E	N/A
		CH_4	E	N/A
		CFCs	I	See Table 4
		HCFC	I	See Table 4
		HFCs	I	See Table 4

3 BASELINE DETERMINATION AND ADDITIONALITY

3.1 BASELINE DETERMINATION

The baseline for a project activity is determined utilizing industry standards and represents the most commonly used practices and technologies.

Food retailers rely heavily on various types of refrigeration systems such as centralized compressor racks that provide cooling throughout the stores via an extensive network of pipes and valves, distributed racks, walk-in coolers, stand-alone units, and beverage refrigerators. Refrigeration systems are "charged" with refrigerant, either at the manufacturing plant, or at the facility where a system is installed (e.g., a supermarket or other food retailer). These systems tend to leak and release refrigerant during normal operations and servicing. The leak rate is dependent upon the type of refrigeration system and is the basis for determining the annual emission rate used in this Methodology.

Under normal operating conditions, depending on the type of equipment and the location, between 1 and 50% of the refrigerant in stationary refrigeration systems leaks each year (ICF 2016; IPCC, 2006; RTOC 2010; EPA, 2015; ACR ODS Destruction Methodology 2017). Even with active leak detection and aggressive maintenance efforts, it is difficult to eliminate leaks completely. Consequently, to maintain proper performance, leaky equipment and systems require periodic servicing to replace the lost refrigerant. Additionally, refrigerants are released at EOL if the refrigerants are not recovered prior to destruction.

For the purposes of determining the annual leak rates, data from the EPA Vintaging Model and from Table 3.3 of the 2016 ICF Accounting Tool to Support Federal Reporting of Hydrofluorocarbon Emissions is used.

Both EPA's Vintaging Model and the 2016 ICF Accounting Tool assume an industry-wide average annual leak rate of 25% for large commercial refrigeration units and a 1% annual leak rate for stand-alone-units. Additionally, according to Table 3.3 of the 2016 ICF Accounting Tool, 25% of stand-alone-units and 85% of large commercial refrigeration units recover refrigerant prior to EOL destruction. Due to the significant amount of refrigerant that leaks at EOL, this methodology includes EOL emissions by amortizing EOL refrigerant losses over the 10-year crediting period.

To date, the industry has relied on R-404a, R-407a, and HFC-134a. In a small number of cases, supermarkets and food retailers have installed systems with non-HFC refrigerants with zero or low-GWP such as CO_2, HCs, and ammonia (see Table 3).

Table 3: Select Low-GWP Alternatives

LOW-GWP SNAP-APPROVED REFRIGERANT	GLOBAL WARMING POTENTIAL
R-290 (propane)	3
R-600a (isobutane)	3
R-1270 (propylene)	1.8
R-744 (CO_2)	1
R-717 (ammonia)	0

These new systems encompass a wide variety of designs, including use of one refrigerant throughout the entire system, or for example, secondary loop systems where the compressor uses a relatively small charge of HFC refrigerant, and the piping throughout the store is filled with heat exchange fluid such as glycol.

This Methodology includes scenarios where advanced refrigeration systems are installed in both new and existing commercial facilities. A measure of the penetration rate of these newer technologies is the number of food retailers certified by EPA's GreenChill Partnership as having a "platinum" rating. The GreenChill platinum certification does not meet the definition of an advanced refrigeration system, as defined by this Methodology, due to the 150 GWP refrigerant threshold[6]. However, it is demonstrative of the low market adoption rate of low-GWP refrigerants. As of June 2018, of the more than 38,500 food retailers in the U.S., only seventy-four (74), or 0.19%, are certified as platinum by GreenChill. Table 4 lists the default baseline factors in projects involving new commercial refrigeration systems that are installed at new facilities. These default assumptions shall be applied in Equations 1 and 2 of Section 4.1.

[6] Food retailers qualify for GreenChill platinum certification by either 1) having a refrigeration system that uses a refrigerant with a GWP less than 150, or 2) having a very small HFC refrigerant charge (less than 0.5 lbs per MBTU/hr total evaporator heat load) and achieving an annual leak rate of 5% or less.[6]

Table 4: Baseline Default Assumptions for Advanced Refrigeration Projects

SEGMENT	EQUIPMENT	CHARGE SIZE (KG)[7]	BASELINE REFRIGERANT[8]	ANNUAL AMORTIZED EMISSION RATE[9]
Large Commercial Refrigeration	Commercial Refrigeration with initial refrigerant charge size of 50 lbs or more.	1.16 kgs refrigerant per MBTU/hr of cooling capacity of the new system	R-407-A (50%) and R-404A (50%) (GWP = 3,014)	25.75%
Stand-Alone Commercial Refrigeration	Vertical Closed Refrigerators	1.3	R-404a (25%) and HFC-134a (75%) (GWP = 2,053)	7.75%
	Vertical Closed Freezers	1.7		
	Vertical Open Refrigerators	1.1		
	Horizontal Open Refrigerator	0.8		
	Horizontal Open Freezer	1.0		
	Deli Cases Refrigerator	0.6		
	Drink Dispensing	0.85		

[7] P&S Research provided the market research for charge sizes (see Appendix A, Table 6).

[8] The potential future applicability of EPA's SNAP 20 and SNAP 21 shall be considered in light of EPA rulemaking following the decision by the Court of Appeals for the District of Columbia in No. 15-1328, 866 F3rd 451 (2017 and Executive Order 13783 (March 28, 2017, 82 FR 16093-97) and any other state or local regulations (such as those being considered by the State of California), with respect to refrigerant use limitations, and addressed through addendums or revisions to this methodology, as needed.

[9] The annual amortized emission rate includes the EOL emissions by amortizing EOL refrigerant losses over the 10-year crediting period. See Appendix A “Baseline Systems Data”.

SEGMENT	EQUIPMENT	CHARGE SIZE (KG)[7]	BASELINE REFRIGERANT[8]	ANNUAL AMORTIZED EMISSION RATE[9]
	Ice Machines	0.85		
	Soft Serve Ice Cream and Frozen Beverages	1.125		
	Food Prep Tables	0.55		
	Blast Chillers	1.25		

For Large Commercial Refrigeration projects that replace an existing system, the actual refrigerant used in the system that was replaced and the refrigerant charge size of the replaced system shall be used. For these projects, data from regulatory compliance reporting or other verifiable historical operating records shall be used in Equations 1 and 2 of Section 4.1 to establish the appropriate baseline refrigerant, charge size, and annual amortized leak rates.

3.2 ADDITIONALITY ASSESSMENT

Emission reductions from the project must be additional, or deemed not to occur in the "business-as-usual" scenario. Assessment of the additionality of a project will be made based on passing the two tests cited below. These two tests require the project proponent to demonstrate that the project activity is surplus to regulations and reduces emissions below the level established in the Methodology.

- Regulatory Surplus Test, and
- Practice-Based Performance Standard

3.2.1 Regulatory Surplus Test

In order to pass the regulatory surplus test a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect as of the project start date that directly or indirectly affect the credited GHG emissions associated with a project. The project proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated with installing advanced refrigeration technologies.

There are no requirements in the United States that require installation of advanced refrigeration technology. EPA issued a regulation that would have prohibited the use of several HFC blends, including R404A and R507A – in new commercial refrigeration installations beginning August 2017, but it was declared invalid by the Court of Appeals for the D.C. Circuit.[10] Therefore, R404A and R507A currently remain available for use.

3.2.2 Practice-Based Performance Standard

In order for a project to qualify for offset credits under this Methodology it must be demonstrated that the sector has a low market adoption rate for advanced refrigeration technology. A market adoption analysis, and hence the additionality demonstration under Applicability Condition 1.2(II), was conducted for the relevant sectors and segments (see Table 1).

A review of US EPA's GreenChill Partnership program data (see Appendix A) indicate that both large commercial and stand-alone commercial refrigeration have low market adoption rates for advanced refrigeration technology. Therefore, project activities within these sectors qualify for offset credit creation under this Methodology.

[10] 80 FR 42869; July 20, 2015; Mexichem Fluor Inc. v. Environmental Protection Agency, D.C. Cir No. 15-1328 (August 2017). A rehearing on that decision was denied on January 25, 2018.

4 QUANTIFICATION OF GHG EMISSION REDUCTIONS

Quantification of project emission reductions requires calculation of baseline emissions and project emissions.

4.1 BASELINE EMISSIONS

Other than for Large Commercial Refrigeration projects that are replacing an existing system, Project Proponents shall use the default emission rates, charge rates, and GWP values listed in Table 4.

For Large Commercial Refrigeration projects that are replacing an existing system, project proponents shall use historical system-specific data for refrigerant type, charge rate of system, and annual emission rates. This data can be generated from regulatory compliance reporting and other verifiable, historical operating documentation.

Baseline emissions will be calculated according to the following formula:

Equation 1

$$\mathbf{BE_y = \sum_i [(Q_{BR,j,i} \times ERA_{REF,j} \times 10)] / 1000 \times GWP_{REF,j}]}$$

WHERE

BE_y	Baseline emissions in year **y** (MT CO_2e)
$Q_{BR,j,i}$	Quantity of refrigerant **j** in equipment **i** used in baseline system (Charge Size of equipment in kgs). Other than for Large Commercial Refrigeration projects where an existing system is being replaced, use the Refrigerant Charge Size default values in Table 4. For Large Commercial Refrigeration projects where existing equipment is being replaced, use regulatory compliance reporting or verifiable historical operating records to establish the charge size of the replaced baseline system.

$ERA_{REF,j}$	Annual amortized emission rate of refrigerant **j** in baseline system (%). Other than for Large Commercial Refrigeration projects where an existing system is being replaced, use the Annual Emission Rate default values in Table 4. For Large Commercial refrigeration projects where existing equipment is being replaced, use regulatory compliance reporting or verifiable historical operating records to establish the annual leak rate of the replaced baseline system which shall be based on the average of the previous two years of baseline system operation prior to installation of advanced refrigeration system.
10	Number of years in the crediting period[11]
$GWP_{REF,j}$	Global warming potential of baseline refrigerant **j.** Other than for Large Commercial Refrigeration projects where an existing system is being replaced, use the GWP default values in Table 4. For Large Commercial refrigeration projects where existing equipment is being replaced, use regulatory compliance reporting or verifiable historical operating records to establish the type of refrigerant historically used.[12]

4.2 PROJECT EMISSIONS

Project emissions will be calculated according to the following formula:

Equation 2

$$\mathbf{PE_y = \sum_i \left[AR_{k,i} \times ERA_{REF,k} \times 10\right] \div 1000 \times GWP_{REF,k}}$$

WHERE

PE_y	Project emissions in year **y** (MT CO_2e)
$AR_{k,i}$	Charge size of alternative refrigerant **k** used in project system from manufacturer specifications **i** (kgs) [13]

[11] All offsets for a project over the 10-year crediting period will be issued following verification.
[12] For installation of a Large Commercial Refrigeration system at an existing facility, project proponents shall use the GWP of the refrigerant used in the system that is replaced. Project proponents shall apply the 100-year value for refrigerant GWPs found in the IPCC Fourth Assessment Report for the historical refrigerant used.
[13] For secondary loop systems, the parameter $AR_{k,i}$ should only include the quantity of primary refrigerant used in the system.

$ERA_{REF,k}$	Annual emission rate of alternative refrigerant **k** set equal to emission rate for baseline system (% per year).
10	Number of years in the crediting period
$GWP_{REF,k}$	Global warming potential of alternative refrigerant **k** used in the project.

4.3 LEAKAGE

By installing an advanced refrigeration system, a project is not increasing overall market demand for refrigeration systems. Thus, there would be no "market-shifting" associated with this project type. Regarding "activity-shifting" leakage, implementation of a project at an existing facility may result in the recovery of refrigerant used in the system that was replaced. However, per applicability conditions 1.2 (III) and 1.2 (IV) any refrigerant recovered in the old system must be destroyed (if CFC or HCFC) or managed in accordance with EPA regulations (40 CFR Part 82, Subpart F) under Section 608 of the Clean Air Act (if HFC). Thus, for this Methodology, leakage can be disregarded.

4.4 PROJECT EMISSION REDUCTIONS

Equation 3

$$\mathbf{ER_y = [BE_y - PE_y]}$$

WHERE

ER_y	Emission reductions in year **y** (MT CO_2e)
BE_y	Baseline emissions in year **y** (MT CO_2e)
PE_y	Project emissions in year **y** (MT CO_2e)

5 MONITORING AND DATA COLLECTION

Each project shall include a monitoring, reporting and verification plan sufficient to meet the requirements of the ACR Standard. The plan shall collect all data required to be monitored and in a manner which meets the requirements for accuracy and precision of this Methodology.

5.1 DESCRIPTION OF THE MONITORING PLAN

These are expanded upon in the sections below. The project proponent must prepare a monitoring plan describing (for each separately) the following: a) project implementation; b) technical description of the monitoring task; c) data to be monitored and collected; d) overview of data collection procedures; e) frequency of the monitoring; f) quality control and quality assurance procedures; g) data archiving; and h) organization and responsibilities of the parties involved in all the above.

The rationale of monitoring project implementation is to document all project activities implemented by the project that could cause an increase in GHG emissions compared to the baseline scenario.

5.2 DATA COLLECTION AND PARAMETERS TO BE MONITORED

The process for monitoring the project's emission reduction parameters includes:

- Identifying and logging the equipment/systems to be installed
- Documentation of the charge size of the alternative refrigerant used in the project from manufacturer specifications.
- For Large Commercial Refrigeration projects that are replacing existing systems, regulatory compliance reporting or verifiable historical operating records to establish the annual leak rate of the replaced baseline system which shall be based on the average of the previous two years of baseline system operation prior to installation of advanced refrigeration system.
- For Large Commercial Refrigeration projects that are replacing CFC or HCFC-based systems, documentation showing proof of destruction for the displaced CFC and HCFC. This documentation shall include the following:

- Bills of lading for shipments of CFC or HCFC from the facility to a destruction facility[14]
- Attestation from project proponent and signed by representatives from the project proponent and the destruction facility that the volume of displaced CFC or HCFC from the baseline system was destroyed including the dates of destruction.

- For Large Commercial Refrigeration projects that are replacing HFC-based systems, documentation showing proof of management in accordance with EPA regulations (40 CFR Part 82, Subpart F) under Section 608 of the Clean Air Act. This documentation shall include the following:
  - Documentation of the recovery of the HFC (i.e. receipts or invoices documenting recovery by service technician) and subsequent management in accordance with EPA regulations.
  - Attestation from project proponent that the volume of displaced HFC from the baseline system was managed in accordance with EPA regulations.

5.2.1 Parameters Monitored

PARAMETER	$Q_{BR,j,i}$
UNITS	kg
DESCRIPTION	Quantity of refrigerant **j** in equipment **i** used in baseline system (charge size of equipment in kgs). Other than for Large Commercial Refrigeration projects where an existing system is being replaced, use the Refrigerant Charge size default values in Table 4. For Large Commercial Refrigeration projects where existing equipment is being replaced, use regulatory compliance reporting or verifiable historical operating records to establish the charge size of the replaced baseline system.
RELEVANT SECTION	4.1
RELEVANT EQUATION(S)	1
SOURCE OF DATA	Table 4, installation, regulatory compliance, or operating records

[14] Destruction shall be conducted at either an approved hazardous waste combustor subject to the Resource Conservation and Recovery Act (RCRA) that maintains a current RCRA permit that states an ODS destruction efficiency of at least 99.99% or at a destruction facility that meets the Montreal Protocol's Technology and Economic Assessment Panel standard that a destruction facility must demonstrate a destruction and removal efficiency of 99.99%.

MEASUREMENT FREQUENCY	Determined once

PARAMETER	$AR_{k,i}$
UNITS	kg
DESCRIPTION	Quantity of alternative refrigerant **k** used in project system **i.**
RELEVANT SECTION	4.2
RELEVANT EQUATION(S)	2
SOURCE OF DATA	Manufacturer specifications
MEASUREMENT FREQUENCY	Determined once

PARAMETER	$ERA_{REF,j}$
UNITS	% per year
DESCRIPTION	Annual amortized emission rate of refrigerant **j** in baseline system (%). Other than for Large Commercial Refrigeration projects where an existing system is being replaced, use the annual amortized emission rate default values in Table 4. For Large Commercial refrigeration projects where existing equipment is being replaced, the annual amortized emission rate is determined using actual annual leak rates based on the average of the verifiable operating records from the previous two years of baseline system operation prior to installation of advanced refrigeration system.
RELEVANT SECTION	4.1

RELEVANT EQUATION(S)	1
SOURCE OF DATA	Table 4, installation, regulatory compliance, or operating records
MEASUREMENT FREQUENCY	Determined once

PARAMETER	$ERA_{REF,k}$
UNITS	% per year
DESCRIPTION	Annual emission rate of alternative refrigerant k used in project system
RELEVANT SECTION	4.2
RELEVANT EQUATION(S)	2
SOURCE OF DATA	Set equal to the emission rate of the baseline system.
MEASUREMENT FREQUENCY	Determined once

PARAMETER	$GWP_{REF,k}$
UNITS	Global Warming Potential (GWP)
DESCRIPTION	GWP of alternative refrigerant **k** used in project system.
RELEVANT SECTION	4.2
RELEVANT EQUATION(S)	2
SOURCE OF DATA	IPCC, published governmental reference (e.g., EPA SNAP), or scientific, peer reviewed publication
MEASUREMENT FREQUENCY	Determined once

APPENDIX A: PERFORMANCE STANDARD DEVELOPMENT AND BASELINE DATA INPUTS

A.1 Performance Standard Development

Section 3.1 summarizes trends in the adoption of advanced refrigeration systems. A measure of the penetration rate of these newer technologies is the number of food retailers certified by EPA's GreenChill Partnership as having a "platinum" rating. The GreenChill platinum certification does not meet the definition of an advanced refrigeration system, as defined by this Methodology, due to the 150 GWP refrigerant threshold[15]. However, it is demonstrative of the low market adoption rate of low-GWP refrigerants. As of June 2018, of the more than 38,500 food retailers in the U.S., only seventy-four (74), or 0.19%, are certified as platinum by GreenChill.[16] There may be additional stores in the United States that have advanced refrigeration systems that have not yet been recognized by the EPA GreenChill Partnership. However, under any scenario, currently the percentage of supermarkets and food retailers in the United States with advanced refrigeration systems is negligible.

A.2 Baseline System Data

Table 5 presents default refrigerants, charge size, and annual emission rates for Large Commercial Refrigeration and Stand-Alone Commercial Refrigeration derived from four sources –the US EPA Vintaging Model, the 2006 IPCC Guidelines for National GHG Inventories, the 2016 ICF Accounting Tool to Support Federal Reporting of Hydrofluorocarbon Emissions, and P&S Market Research. Charge sizes are based on actual market data gathered by P&S Market Research (Table 6).

For the purposes of determining the annual amortized emission rates, data from the EPA Vintaging Model and from Tables 3.3 (Table 7) and 3.6 (Table 8) of the 2016 ICF Accounting Tool are used. For large commercial refrigeration units, the annual amortized emission rate of 25.75% is calculated using an annual leak rate of 25%, a product lifetime of 18 years, 90% of refrigerant remaining at EOL, and a 15% refrigerant disposal rate at EOL. For stand-alone commercial refrigeration, an annual amortized emission rate of 7.75% is calculated using a 1%

[15] Food retailers qualify for GreenChill platinum certification by either 1) having a refrigeration system that uses a refrigerant with a GWP less than 150, or 2) having a very small HFC refrigerant charge (less than 0.5 lbs per MBTU/hr total evaporator heat load) and achieving an annual leak rate of 5% or less.
[16] http://www2.epa.gov/greenchill/greenchill-store-certification-awards

annual leak rate, a 10-year product lifetime, 90% of refrigerant remaining at EOL, and a 75% refrigerant disposal rate.

Large Commercial Refrigeration Annual Amortized Emission Rate Calculation

- 25% annual leak rate (see Table 7)
- 18-year equipment lifetime (see Table 8)
- 25% annual leak rate * 18 years = ***450% lifetime refrigerant loss***[17]
- 90% refrigerant remaining at EOL (see Table 7)
- 15% disposal rate (85% is recovered) (see Table 7)
- 90% * 15% = ***13.5% refrigerant loss at EOL***
- (450% refrigerant loss + 13.5% EOL refrigerant loss) /18 years = ***25.75% annual amortized emission rate***

Stand-Alone Commercial Refrigeration Annual Amortized Emission Rate Calculation

- 1% annual leak rate (see Table 7)
- 10-year equipment lifetime (see Table 8)
- 1% annual leak rate * 10 years = ***10% lifetime refrigerant loss***
- 90% refrigerant remaining at EOL (see Table 7)
- 75% disposal rate (25% is recovered) (see Table 7)
- 90% * 75% = ***67.5% refrigerant loss at EOL***
- (10% refrigerant loss + 67.5% EOL refrigerant loss) /10 years = ***7.75% annual amortized emission rate***

[17] Large commercial refrigeration units are re-charged on a regular basis.

Table 5: Baseline System Charge Size and Emission Rates

SEGMENT	PRODUCT	CHARGE SIZE (KGS)[18]	BASELINE REFRIGERANT[19]	ANNUALIZED EMISSION RATE[20]
Large Commercial Refrigeration	Commercial refrigeration with initial refrigerant charge size of 50 lbs or more.	1.16 kgs refrigerant per MBTU/hr of cooling capacity of the new system	R-407-A (50%) and R-404A (50%) (GWP = 3,014)	25.75%
Stand-Alone Commercial Refrigeration	Vertical Closed Refrigerators	1.3	Refrigerant: R-404a (25%) and HFC-134a (75%) (GWP = 2,053)	7.75%
	Vertical Closed Freezers	1.7		
	Vertical Open Refrigerators	1.1		
	Horizontal Open Refrigerator	0.8		
	Horizontal Open Freezer	1.0		
	Deli Cases Refrigerator	0.6		
	Drink Dispensing	0.85		
	Ice Machines	0.85		

[18] P&S Research provided the market research for stand-alone commercial refrigeration charge sizes (see Table 6)
[19] The potential future applicability of EPA's SNAP 20 and SNAP 21 shall be considered in light of EPA rulemaking following the decision by the Court of Appeals for the District of Columbia in No. 15-1328, 866 F3rd 451 (2017 and Executive Order 13783 (March 28, 2017, 82 FR 16093-97) and any other state or local regulations (such as those being considered by the State of California), with respect to refrigerant use limitations, and addressed through addendums or revisions to this methodology, as needed.
[20] The annualized emission rate includes the EOL emissions by amortizing EOL refrigerant losses over the 10-year crediting period. See Appendix A "Baseline Systems Data".

SEGMENT	PRODUCT	CHARGE SIZE (KGS)[18]	BASELINE REFRIGERANT[19]	ANNUALIZED EMISSION RATE[20]
	Soft Serve Ice Cream and Frozen Beverages	1.125		
	Food Prep Tables	0.55		
	Blast Chillers	1.25		

Table 6: P&S Market Survey Data on Charge Size

PRODUCT	CHARGE RANGE (KGS)
Vertical Closed Refrigerators	1.2 – 1.4
Vertical Closed Freezers	1.5 – 1.9
Vertical Open Refrigerators	1.0 – 1.2
Horizontal Open Refrigerator	0.7 – 0.9
Horizontal Open Freezer	0.9 – 1.1
Deli Cases Refrigerator	0.4 – 0.8
Drink Dispensing	0.7 – 1.0
Ice Machines	0.6– 1.1
Soft Serve Ice Cream and Frozen Beverages	1.05 – 1.2
Food Prep Tables	0.4 – 0.7
Blast Chillers	1.1 – 1.4

Table 7: ICF 2016 Accounting Tool Table 3.3

Table 3-3. Default F-gas Emission Factors for Refrigeration and A/C Equipment

Equipment Type	Installation Emission Factor [a] k (% of capacity)	Operating Emission Factor x (% of capacity/yr)	Refrigerant Remaining at Disposal y (% of capacity)	Recovery Efficiency z (% of remaining)
Room A/C		0.9%	94%	21%
Other residential A/C and heat pumps		8%	80%	50%
Other commercial A/C and heat pumps		8%	80%	70%
Chillers	0.5%	2%	95%	85%
Household refrigerators and/or freezers		0.5%	91%	31%
Stand-alone retail refrigerators and freezers		1%	90%	25%
Walk-in refrigerators and freezers	2.0%	12%	90%	70%
Supermarket refrigeration and condensing units	2.0%	25%	90%	85%
Medium cold storage	1.0%	25%	80%	80%
Large cold storage	1.0%	25%	80%	80%
Refrigerated transport - land		20%	50%	60%
Refrigerated transport - marine		20%	50%	60%
Passenger car A/C		8.9%	50%	20%
Light-duty or heavy-duty truck A/C		8.9%	50%	20%
Bus A/C		10%	50%	40%

Table 8: ICF 2016 Accounting Tool Table 3.6[21]

Table 3-6. Default Refrigerant Types and Charge Sizes for Refrigeration and A/C Equipment

Equipment Type	Equipment Charge Size (kg)	Equipment Lifetime (yrs)	Default Refrigerant[a]	Refrigerant F-Gas Composition	GWP (SAR)	GWP (AR4)	Percent Containing HFCs in 2014
Household refrigerators and/or freezers	0.15	14	R-134a	100% HFC-134a	1,300	1,430	100%
Stand-alone retail refrigerators and freezers	0.4	10	R-134a	100% HFC-134a	1,300	1,430	100%
Walk-in refrigerators and freezers	10	20	R-404A	44% HFC-125; 4% HFC-134a; 52% HFC-143a	3,260	3,922	50%
Supermarket refrigeration	1,360	18	R-404A	44% HFC-125; 4% HFC-134a; 52% HFC-143a	3,260	3,922	50%
Refrigerated transport - land	6	12	R-134a	100% HFC-134a	1,300	1,430	100%
Refrigerated transport - marine	6	12	R-134a	100% HFC-134a	1,300	1,430	100%
Medium cold storage	565	25	R-404A	44% HFC-125; 4% HFC-134a; 52% HFC-143a	3,260	3,922	50%
Large cold storage	7,546	25	R-404A	44% HFC-125; 4% HFC-134a; 52% HFC-143a	3,260	3,922	50%
Chillers	500	23	R-134a	100% HFC-134a	1,300	1,430	30%
Room A/C	0.5	12	R-410A	50% HFC-32; 50% HFC-125	1,725	2,088	40%
Other residential A/C and heat pumps	5	15	R-410A	50% HFC-32; 50% HFC-125	1,725	2,088	40%
Other commercial A/C and heat pumps	13	25	R-410A	50% HFC-32; 50% HFC-125	1,725	2,088	30%
Passenger car A/C	0.6	12	R-134a	100% HFC-134a	1,300	1,430	100%
Light-duty or heavy-duty truck A/C	0.8	12	R-134a	100% HFC-134a	1,300	1,430	100%
Bus A/C	5	12	R-134a	100% HFC-134a	1,300	1,430	90%

[21] Per the ICF report, the HFC default refrigerant presented in Table 8 is the one assumed to represent the single highest share of installed refrigerants for a particular equipment type according to the U.S. EPA Vintaging Model. In this methodology, ACR has chosen to be more precise in its representation of default refrigerants and therefore have included blended baseline refrigerants based on market research and expert review. These are presented in Tables 4 and 5.

APPENDIX B: REFERENCES

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American Carbon Registry
AT WINROCK INTERNATIONAL

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

CERTIFIED RECLAIMED HFC REFRIGERANTS

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September 2018

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ACKNOWLEDGEMENTS

This methodology was developed by:

EOS Climate

Financial support for the development of this methodology was provided by:

A-Gas Americas

Diversified Pure Chem

Hudson Technologies

ACRONYMS AND DEFINITIONS

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry (ACR) Standard apply.

TERM	ACRONYM (if applicable)	DEFINITION
Aerosol Product		A product pressurized by a propellant that expels its contents from a canister through a nozzle. Propellants include compressed gases and liquefied gases. Liquefied gases include HFCs, including HFC-134a, which can be recovered and reclaimed for re-use as a refrigerant, at which point it is considered a reclaimed HFC refrigerant.
Certified reclaimed HFC refrigerant		Used (recovered) HFC that has been reclaimed by an EPA-certified reclaimer to meet the AHRI 700-2015 Standard for Specifications for Fluorocarbon Refrigerants[1] by an EPA certified reclaimer, and tested by an AHRI certified refrigerant testing laboratory to meet the AHRI Standard.
Chlorofluorocarbon	CFC	A class of compounds of carbon, hydrogen, chlorine, and fluorine that are commonly used as refrigerants.
GHG Source, Sink, or Reservoir	SSR	• GHG Source – Physical unit or process that releases a GHG into the atmosphere • GHG Sink – Physical unit or process that removes a GHG from the atmosphere

[1] Air Conditioning, Heating, and Refrigeration Institute (AHRI) 700-2015 Standard for *Specifications for Fluorocarbon Refrigerants.* www.ahrinet.org

TERM	ACRONYM (if applicable)	DEFINITION
		• GHG Reservoir - Physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store or accumulate a GHG removed from the atmosphere by a GHG sink or captured from a GHG source.
Hydrochlorofluorocarbon	HCFC	A class of compounds of carbon, hydrogen, chlorine, and fluorine that are commonly used as refrigerants.
Hydrofluorocarbon	HFC	A class of compounds that contain carbon, fluorine, and hydrogen that are commonly used as refrigerants, as well as solvents, aerosol propellants, and foam blowing agents.
HFC Refrigerant		Refrigerant comprised of either a mix of hydrofluorocarbons (HFCs) referred to as an "HFC blend", or a single HFC.
Project activity		• The reclamation and use of certified reclaimed HFC refrigerants to service existing refrigeration and air conditioning equipment, • The reclamation and use of certified reclaimed HFC refrigerants in newly manufactured refrigeration or air conditioning equipment
Refrigeration or air conditioning equipment		An Appliance[2], or component parts of a system, that uses refrigerant to provide cooling under controlled conditions.

[2] Per 40 CFR §82.3, an "Appliance" is defined as "any device which contains and uses a refrigerant and which is used for household or commercial purposes, including, without limitation, any air conditioner, refrigerator, chiller, or freezer."

TERM	ACRONYM (if applicable)	DEFINITION
Use of certified reclaimed HFC refrigerant		Production by the reclaimer, plus transfer/return/sale of certified reclaimed HFC refrigerant to refrigerant distributors, wholesalers, original equipment manufacturers, service technicians, or refrigerant end-users who are in the business of selling or using HFC refrigerant for use in refrigeration or air conditioning equipment.

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1 BACKGROUND AND APPLICABILITY

1.1 SUMMARY DESCRIPTION OF THE METHODOLOGY

Modern society is dependent on refrigeration to process, store and transport food, as well as on air conditioning in the built environment and motor vehicles. Reliable and cost-effective cooling is also critical for other commercial and industrial processes, such as in pharmaceutical and chemical production, oil refining, aerospace and defense technologies, data servers, and ice rinks. These diverse applications typically rely on refrigerants, the chemical coolants that can reach low temperatures and transfer heat by undergoing a phase change between liquid and gas (through condensation).

Up until the mid-1990s, chlorofluorocarbons (CFCs) were in widespread use as refrigerants. CFCs destroy the Earth's protective ozone layer and are also powerful greenhouse gases (GHGs). Under the Montreal Protocol and United States Clean Air Act, nearly all CFC production ended in the United States in 1996.[3] As a result, many applications transitioned to using hydrochlorofluorocarbon (HCFC) refrigerants, which also contribute to ozone depletion and climate change, although to a lesser extent than CFCs. With the phase out of HCFCs currently underway, the most commonly used refrigerants today are hydrofluorocarbons (HFCs). HFCs, while safe for the ozone layer, are also powerful GHGs when released to the atmosphere.

Across the various refrigeration and air conditioning applications, there are a number of approaches that can be used to reduce GHG emissions from both new and installed equipment.

1.1.1 Use of Certified Reclaimed HFC refrigerants

For the large installed base of HFC equipment and infrastructure that will continue to operate, there are a number of ways that emissions can be reduced, including:

- Monitoring and timely leak repair for systems that are inherently prone to leaks,

[3] After 1996, the Montreal Protocol authorized limited production of CFCs for "essential uses" as propellants in medical devices (metered dose inhalers relied upon by asthmatics) and for laboratory and analytical uses. Production for essential medical uses ended in the U.S. on January 1, 2012. The exemption for de minimis CFC production essential laboratory and analytical uses remains in effect.

- Proper training and practices by professional engineers and contractors that install and service equipment, and
- Refrigerant management practices throughout the lifecycle of the refrigerant, from production, distribution, recovery, reclamation, and end-of-life disposal.

Another opportunity to mitigate emissions is by filling refrigeration equipment with reclaimed HFC refrigerants. Typically, virgin (newly produced, never previously used) refrigerant is used to "charge" refrigeration and A/C systems and various types of equipment when they are manufactured and installed, and when the systems leak during normal operations. Re-using previously used HFC that has been recovered[4], and reclaimed[5] to virgin-grade refrigerant purity, either to "recharge" existing systems that require servicing, or in newly manufactured equipment, displaces new production of virgin refrigerant that would otherwise be manufactured to meet that demand.

This Methodology focuses only on HFCs, and does not address HCFC-22, which is being phased out of production[6].

Table 1: Eligible Refrigerant Sectors and Segments

Sectors that are eligible under this Methodology.

PROJECT ACTIVITY	REFRIGERANT SECTOR	ELIGIBLE SEGMENTS IN SECTOR
Use of Certified	Domestic Refrigeration	Residential refrigerators and freezers

[4] Refrigerant that is recovered from refrigeration or air conditioning equipment is removed/extracted by a certified technician using certified recovery equipment from appliances during servicing or at end-of-life. HFCs can also be recovered from other sources including discarded aerosol cans, and reclaimed for re-use as refrigerant.

[5] Reclaimed refrigerant is used (recovered) refrigerant that has been processed to remove impurities and tested by an EPA certified reclaimer and certified to meet the AHRI 700-2015 Standard for Specifications for Fluorocarbon Refrigerants.

[6] Production and import of R-22 is regulated in the United States by annual allocations issued by the EPA, in accordance with the phasedown schedule established in the Montreal Protocol and United States Clean Air Act. Until the complete phase-out in 2020, R-22 can only be produced/imported, and used, to service equipment manufactured prior to 2010. This methodology makes a conservative assumption that 100% of the remaining EPA allocations will be filled, i.e., the same quantity of R-22 will be produced/imported and ultimately used regardless of whether individual facilities or manufacturers choose to use reclaimed R-22 instead of virgin R-22. While not accounted for in this methodology, greater use of reclaimed R-22 absolutely has positive environmental benefit that was accounted for by the United States EPA in determining the annual R-22 allocations. In contrast, there are no controls in the United States on production/import of HFC refrigerants so increased use of reclaimed HFC refrigerant to meet demand has a direct impact on the volumes of HFC refrigerants that would otherwise be produced/imported.

PROJECT ACTIVITY	REFRIGERANT SECTOR	ELIGIBLE SEGMENTS IN SECTOR
Reclaimed HFC Refrigerants	Commercial Refrigeration, also known as Retail Food Refrigeration	Equipment used to store and display chilled and frozen goods for commercial sale such as in supermarkets, convenience stores, bakeries, and restaurants. This equipment includes centralized supermarket systems, remote condensing units, and stand-alone equipment (e.g., beverage vending machines, stand-alone display cases).
	Cold Storage Warehouses	Storage for meat, produce, dairy products, and other perishable goods.
	Industrial Process Refrigeration	Chemical, pharmaceutical, petrochemical and manufacturing industries, industrial ice machines and ice rinks.
	Transport Refrigeration	Refrigerated truck trailers, railway freight cars, ship holds, and other shipping containers.
	Mobile Air Conditioning	Automobiles, trucks, buses, and other motor vehicles.
	Stationary Air Conditioning	Comfort cooling for homes and commercial buildings, including multi-family buildings, office buildings, hospitals, universities, shopping malls, airports, sports arenas.

This Methodology provides the quantification framework for the creation of carbon offset credits from the reductions in GHG emissions resulting from the use of certified reclaimed HFCs. The Methodology is intended to be used as an incentive within the relevant industries to increase these activities.

1.2 APPLICABILITY CONDITIONS

Projects that avoid the emissions of refrigerant gases in the following activities are considered a "project activity":

- The reclamation and use of certified reclaimed HFC refrigerants to service existing refrigeration and air conditioning equipment, and

- The reclamation and use of certified reclaimed HFC refrigerants in newly manufactured refrigeration or air conditioning equipment.

For purposes of this Methodology, "reclamation and use" of certified reclaimed HFC refrigerant refers specifically to the production of such refrigerant (by a certified refrigerant reclaimer) and the subsequent sale, title transfer or return to a refrigerant distributor, refrigerant wholesaler, or an end-user (either through direct sale, title transfer or return to an end user or through installation conducted via service technician) for use in refrigeration or air conditioning equipment.

In addition to satisfying the latest ACR program eligibility requirements as found in the ACR Standard, project activities must satisfy the following conditions to be applicable:

I. The project is located in North America.
II. The project is within a sector and segment which has a low adoption rate for the relevant project activity ("Eligible Project Activity" & "Eligible Refrigerant Sector/Segment" (see Table 1)).
III. The refrigerant must meet the definition of certified reclaimed HFC refrigerant found in this Methodology.

1.3 REPORTING PERIODS

- Projects shall have one reporting period which must not exceed 12 months in length.
- Emission reductions shall be quantified for a period not to exceed 12 months based on the total amount of certified reclaimed HFC produced and the subsequent sale, title transfer or return to a refrigerant distributor, refrigerant wholesaler, or an end-user (either through direct sale, title transfer or return to an end user or through installation conducted via service technician) for use in refrigeration or air conditioning equipment.
- A reporting period begins on the date that the initial volume of certified reclaimed HFC is sold, title transferred, or returned to a refrigerant distributor, refrigerant wholesaler, or and end-user (either through direct sale, title transfer or return to an end user or through installation conducted via service technician) for use in refrigeration or air conditioning equipment.

1.4 CREDITING PERIODS

A Crediting Period is the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. The crediting period for all project activities shall be ten years.

1.5 PERIODIC REVIEWS AND REVISIONS

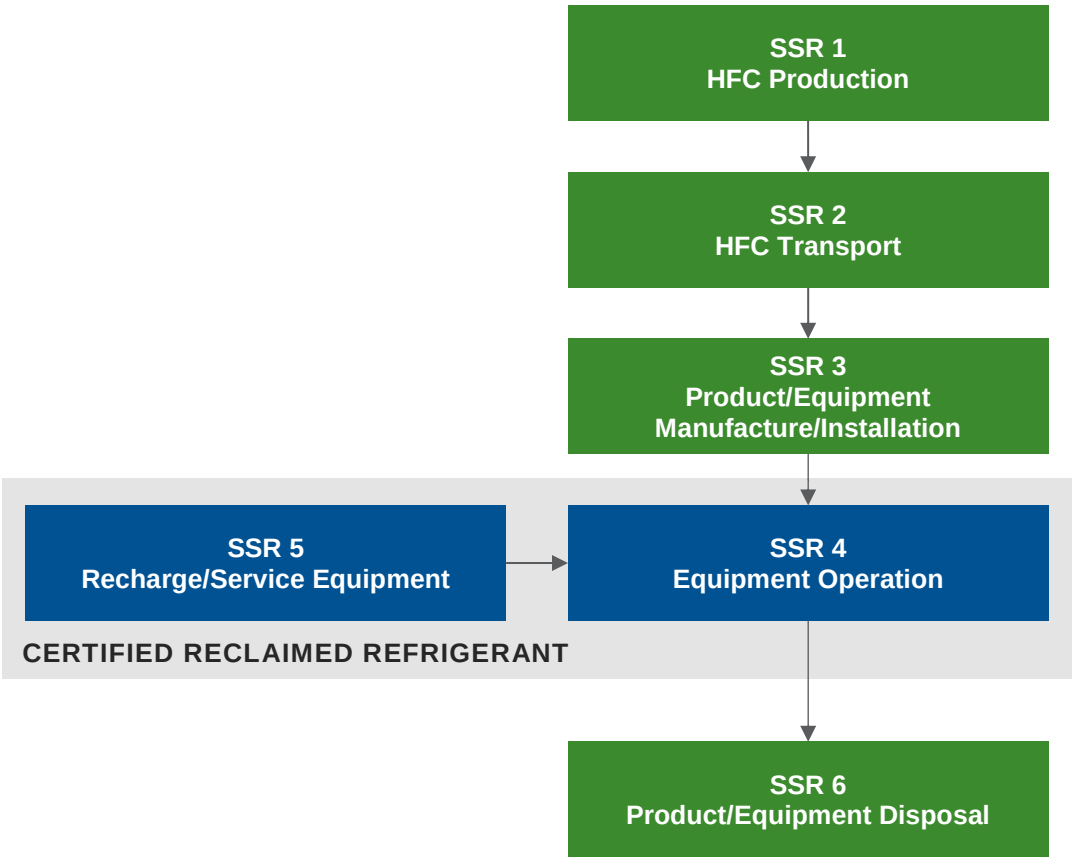
ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project's activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the Methodology.

2 PROJECT BOUNDARIES

2.1 GEOGRAPHIC BOUNDARY

For projects using certified reclaimed HFC refrigerant, the project boundary, depicted by the light grey box in Figure 1, is the physical and geographical site where the reclaimed HFC refrigerant is produced in the project by a certified refrigerant reclaimer, for use in equipment operations and servicing/recharging to replace refrigerant that leaks or to charge newly manufactured refrigeration or air conditioning equipment.

Figure 1: Project Boundary Diagram for Certified Reclaimed Refrigerant



Within the boundaries, the sources of GHG emissions are from the operations of the refrigeration and air conditioning equipment, including recharging equipment that has leaked. Table 2 lists the GHG sources included and excluded depending on whether the sources are within or outside project boundaries.

Table 2: Greenhouse Gases and Sources

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFI-CATION METHOD
1 HFC Production	Fossil fuel emissions from the production of HFCs	CO_2	E	N/A
		CH_4	E	N/A
	HFC leaks during HFC production	HFCs	E	N/A
2 Refrigerant Transport	Fossil fuel emissions from transport of HFCs	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	HFC leaks during transport	HFCs	E	N/A
3 Equipment Manufacture and Installa-tion	Emissions of HFCs during manufacture or installation of refrigeration or A/C equip-ment or system or product	HFCs	E	N/A
4 Equipment Operations	Fossil fuel emissions from the operation of the refriger-ation or A/C equipment or system	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	HFC leaks from the opera-tion of the refrigeration or A/C equipment or system or product	HFCs	I	Equation 1
5 Service Equipment	Fossil fuel emissions from servicing refrigeration or A/C equipment or system to re-place leaked refrigerant	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFI-CATION METHOD
	HFC emissions from servic-ing refrigeration or A/C equipment or system to re-place leaked refrigerant	HFCs	I	Equation 1
6 Equipment Disposal	Emissions from the disposal of the equipment at end-of-life including destruction of refrigerant	HFCs	E	N/A

3 BASELINE DETERMINATION AND ADDITIONALITY

3.1 BASELINE DETERMINATION

The baseline for a project activity is determined utilizing industry standards and represents the most commonly used practices and technologies.

Refrigeration and air conditioning (A/C) appliances and other components that comprise a system are "charged" with refrigerant, either at the manufacturing plant, or at the facility where a system is installed, e.g., a supermarket.

Under normal operating conditions, depending on the type of equipment and the location, between 1 and 50% of the refrigerant in stationary and mobile air conditioning and refrigeration systems leaks each year (IPCC/TEAP, 2006; IPCC, 2006; RTOC 2010; EPA, 2014; ACR ODS Methodology). Even with active leak detection and aggressive maintenance efforts, it is difficult to eliminate leaks completely.[7] Consequently, to maintain proper performance, leaky equipment and systems require periodic servicing to replace the lost refrigerant.

In the majority of situations, virgin (newly produced, never previously used) refrigerant is used both to charge newly manufactured equipment and systems, and to "recharge" systems that leak during normal operations.

As an alternative, reclaimed refrigerant can be used. This is refrigerant that has been previously used, recovered from other air conditioning or refrigeration equipment or disposed aerosol products (e.g., cleaning and personal care products, office dusters, safety horns, asthma inhalers), and processed to remove impurities and restored to virgin-grade quality.[8] Using reclaimed refrigerant effectively displaces the use – and therefore avoids production and eventual emissions – of virgin refrigerant. Within the existing reclamation industry, there is capacity to significantly increase reclaimed refrigerant use (EPA, 2014). Thus, using reclaimed refrigerant would result in a net GHG reduction.

Reclaimed HFCs comprise a small proportion of the HFC refrigerants that are in use today in the United States. Unlike the strong incentive to reclaim CFC refrigerants and HCFC-22 that

[7] Refrigerants can also be released during equipment servicing or when the system is decommissioned.

[8] HFCs recovered from air conditioning or refrigeration equipment, or discarded aerosol products can be restored to virgin grade quality for re-use as refrigerant, whereupon the material becomes defined as "reclaimed HFC refrigerant". In other words, this Methodology allows credits for use of reclaimed HFC refrigerants sourced from both refrigeration and air conditioning equipment, and from discarded aerosol products.

have been or are being phased out, there is currently little incentive for recovery, reclamation, and re-sale of HFC refrigerants.

Appendix A.1 provides the basis for the rate by which HFCs are reclaimed in the United States under the baseline scenario in this Methodology.

To calculate baseline emissions of HFC refrigerants in the United States, emission factors for individual HFC refrigerants were calculated, as detailed in Appendix A.2. Table 3 lists the 10-year emission rates used in this Methodology for HFCs that are recovered from refrigeration, A/C equipment, or aerosol products (see Appendix A.3 for a discussion of the baseline emission factor for aerosol products).

All HFC refrigerants that are placed into commerce – either through sale or through any other method to transfer title – are used. For purposes of this Methodology, it is assumed that from the time that any reclaimed HFC refrigerant is sold or otherwise transferred from the reclaimer to a distributor, wholesaler, service technician, or an end-user (e.g., equipment manufacturer, supermarket) that refrigerant will be used.

Emissions of refrigerant that occur during equipment manufacturing or installation are less than 3% of the initial charge (IPCC, 2006) and are therefore considered negligible and not included in this Methodology.

Table 3: 10-Year Emission Rates for Predominant HFCs[9]

HFC RECOVERED FROM REFRIGERATION OR A/C EQUIPMENT	10-YEAR EMISSION RATE (%)
HFC-134a	76%
HFC-23	73%
HFC-32	64%
R-404A	89%
R-407A	89%
R-407C	68%
R-410A	66%
R-417C	86%

[9] See Appendices A.2 and A.3

HFC RECOVERED FROM REFRIGERATION OR A/C EQUIPMENT	10-YEAR EMISSION RATE (%)
R-422B	68%
R-422C	89%
R-422D	89%
R-507A	89%

HFC RECOVERED FROM DISCARDED AEROSOL PRODUCTS	10-YEAR EMISSION RATE (%)
HFC-134a	100%
HFC-152a	100%

As discussed in Appendix A.1, for purposes of this Methodology, the baseline reclamation rate for HFCs in the United States is set conservatively at 8.9% which is the R-22 reclaim rate from 2013 which is the most recent year in which there are EPA published data. As new data become available on R-22 reclamation, and eventually HFC reclamation, ACR will update this factor.

Table 4 lists the GWPs of the HFC refrigerants for both the baseline and project scenario calculations. As additional refrigerants become available through United States EPA SNAP listings[10] and market adoption, ACR will update this table.

[10] http://www.epa.gov/spdpublc/snap/refrigerants/lists/index.html

Table 4: GWPs of Predominant HFC Refrigerants

HFC REFRIGERANT	GLOBAL WARMING POTENTIAL[11]
HFC-152a	124
HFC-32	675
HFC-134a	1,430
R-407C	1,774
R-417C	1,820
R-410A	2,088
R-407A	2,107
R-422B	2,525
R-422D	2,730
R-422C	3,085
R-404A	3,922
R-507A	3,985
HFC-23	14,800

3.2 ADDITIONALITY ASSESSMENT

Emission reductions from the project must be additional, or deemed not to occur in the "business-as-usual" scenario. Assessment of the additionality of a project will be made based on passing the two tests cited below. These two tests require the project proponent to demonstrate that the project activity is surplus to regulations and reduces emissions below the level established in the Methodology.

- Regulatory Surplus Test, and

[11] IPCC, Fourth Assessment Report (100 year)

- Practice-Based Performance Standard

3.2.1 Regulatory Surplus Test

In order to pass the regulatory surplus test a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect as of the project start date that directly or indirectly affect the credited GHG emissions associated with a project. The project proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated with using certified reclaimed HFC refrigerant..

Currently, there are no restrictions in the United States or elsewhere in North America on the quantities of HFCs that can be produced, imported, or used. There are no requirements on the quantities of reclaimed HFC refrigerants that must be used for any application. Users are free to use virgin HFC, stockpiled HFC, or recycled or reclaimed HFC refrigerant in any amount of their choosing. There are regulatory requirements pertaining to certification of the equipment used to recover ODS refrigerants and the service technicians that handle ODS refrigerants, as well as certification requirements for refrigerant reclaimers. All regulatory requirements that apply to ODS refrigerants must be complied with as part of projects involving HFC refrigerants under this Methodology.

As discussed in Section A.1, because of the lack of production controls for HFCs, combined with the additional costs to recover, transport, and separate/process refrigerants back to virgin purity levels, there is currently little incentive for recovery, reclamation, and re-sale of HFC refrigerants. Based on U.S. EPA data on reclamation of HCFC-22 (for which there is a strong incentive to recover and reclaim), and industry information, the percentage of available HFCs that are reclaimed in the U.S. is extremely low. For purposes of this Methodology, a conservative assumption is made that the rate by which HFC refrigerants are reclaimed under the baseline scenario is the same (8.9%) as the R-22 reclaim rate based on the most recent data.

3.2.2 Practice-Based Performance Standard

In order for a project to qualify for offset credits under this Methodology it must be demonstrated that the sector has a low market adoption rate for certified reclaimed HFC refrigerant. A market adoption analysis, and hence the additionality demonstration under Applicability Condition 1.2 (II) was conducted for the relevant sectors and segments (see Table 1). A review of US EPA's reclamation data (see Appendix A.1) indicate that these sectors and segments have a low market adoption rate for using certified reclaimed HFCs. Therefore, project activities within these sectors and segments qualify for offset credit creation under this Methodology.

4 QUANTIFICATION OF GHG EMISSION REDUCTIONS

Quantification of project emission reductions requires calculation of baseline emissions and project emissions.

4.1.1 Baseline Emissions

This is the amount of baseline emissions that would take place without the use of certified reclaimed HFCs. It is equal to the total amount of reclaimed HFC refrigerant produced and the subsequent sale, title transfer or return to a refrigerant distributor, refrigerant wholesaler, or an end-user (either through direct sale, title transfer or return to an end user or through installation conducted via service technician) for use in refrigeration or air conditioning equipment during the reporting period. In the absence of the project, most of the refrigerant used to recharge the system would have come from virgin HFC production, and some would come from HFCs that would normally be reclaimed.

For projects using certified reclaimed HFC refrigerant, the baseline emissions are calculated by the following:

Equation 1

$$\mathbf{BE_{HFC_{rp}}} = \sum_{\mathbf{n}}^{\mathbf{y}} [(\mathbf{VR_{HFC,j,_{rp}}} \times \mathbf{ER10_{HFC,j}} \times \mathbf{GWP_{HFC,j}})] \times (\mathbf{1} - \mathbf{RR_{BL}}) \div \mathbf{1000}$$

WHERE

$BE_{HFC_{rp}}$	Baseline emissions during the reporting period (MT CO_2e)
$VR_{HFC,j,_{rp}}$	Total quantity of virgin HFC refrigerant **j** used to recharge equipment during the reporting period (kgs), derived from the quantity of monitored certified reclaimed HFC refrigerant that is documented according to the procedures in Section 3.1 and Section 5
$ER10_{HFC,j}$	The 10-year loss rate of HFC refrigerant **j** from equipment (%; see Table 3)
$GWP_{HFC,j}$	The global warming potential of HFC refrigerant **j** (see Table 4)

RR_{BL}	Baseline Refrigerant Reclamation Rate (% per year)[12]

4.1.2 Project Emissions

As discussed above in Section 3, by using previously used, reclaimed HFC refrigerants, project participants are displacing new production of virgin HFC. In this Methodology, any project related emissions from using reclaimed refrigerant, for example, from transport of certified reclaimed HFCs, are considered negligible and outside the project boundary. Thus, project activity emissions can be disregarded.

4.1.3 Leakage

In GHG project literature, leakage is a term that refers to secondary effects associated with where the GHG emission reductions of a project may be negated by shifts in market activity or shifts in materials, infrastructure, or other physical assets associated with the project. Projects involving certified reclaimed HFC refrigerant would not increase demand for refrigerant beyond current baseline demand, i.e., use of more reclaimed refrigerant would not cause an increase in virgin HFC production (to the contrary), or increase refrigerant emission rates. Therefore, for this Methodology, "leakage" can be disregarded.

4.1.4 Project Emission Reductions

Equation 2

$$\mathbf{ER_{rp} = BE_{HFC_{rp}}}$$

WHERE

ER_{rp}	Project emission reductions during reporting period (MT CO_2e)
$BE_{HFC_{rp}}$	Baseline emissions of HFC refrigerant during reporting period (MT CO_2e)

[12] Percentage of HFC refrigerant that would be reclaimed in the business-as-usual case, currently estimated to be 8.9% per year (see Appendix A.1)

5 MONITORING AND DATA COLLECTION

Each project shall include a monitoring, reporting and verification plan sufficient to meet the requirements of the ACR Standard. The plan shall collect all data required to be monitored and in a manner which meets the requirements for accuracy and precision of this Methodology.

5.1 DESCRIPTION OF THE MONITORING PLAN

These are expanded upon in the sections below. The project proponent must prepare a monitoring plan describing (for each separately) the following: a) project implementation; b) technical description of the monitoring task; c) data to be monitored and collected; d) overview of data collection procedures; e) frequency of the monitoring; f) quality control and quality assurance procedures; g) data archiving; and h) organization and responsibilities of the parties involved in all the above.

The rationale of monitoring project implementation is to document all project activities implemented by the project that could cause an increase in GHG emissions compared to the baseline scenario.

5.2 DATA COLLECTION AND PARAMETERS TO BE MONITORED

For a specific quantity of HFC refrigerants that are reclaimed, monitoring the emission reduction parameters includes:

- Where the HFC was recovered by service technicians in individual containers of 500 pounds gross refrigerant weight or more, documentation of the point of origin of the reclaimed HFC including:
  - Facility name and address where HFC was recovered;
  - Equipment/product (including, if available, manufacturer, model number, and serial number; if unavailable, a description of the equipment/product) from which HFC was extracted;
  - Date(s) of recovery;
  - The cylinder number, gross refrigerant weight, and net refrigerant weight of each container received by the EPA-certified reclaimer;
  - Date(s) received by the EPA-certified reclaimer;

- Attestation from EPA-certified reclaimer regarding the source of the HFC refrigerant that is reclaimed. Specifically, this attestation must document whether the reclaimer has previously obtained recovered HFC refrigerant from the source and, if so, the dates on which that HFC refrigerant was acquired; and
- Chain of custody and ownership of the recovered HFC must be demonstrated from the point of origin through the delivery of recovered HFC to the EPA-certified reclaimer. The following information must be provided to track chain of custody:
  - Names and addresses for all persons/entities buying and selling the recovered HFC;
  - The quantity of HFC purchased/sold at each transaction.

- Where HFCs were recovered by service technicians in individual containers of less than 500 pounds and aggregated with other recovered HFCs to greater than 500 pounds gross refrigerant weight in an individual container prior to delivery to an EPA-certified reclaimer, documentation of the point of origin of the reclaimed HFC including:
  - Name and address of the service company, wholesaler or distributor where recovered HFC was aggregated to individual containers of greater than 500 pounds;
  - If applicable, chain of custody and ownership of the recovered HFC must be demonstrated from the point of origin (location where recovered HFC was aggregated into individual containers to greater than 500 pounds) through to the delivery of recovered HFC to an EPA-certified reclaimer. The following information must be provided to track chain of custody:
    - Names and addresses for all entities buying and selling the recovered HFC;
    - The quantity of HFC purchased/sold at each transaction.
  - The cylinder number, gross refrigerant weight, and net refrigerant weight of each container received by the reclaimer; and
  - Date(s) received by the reclaimer.

- Where the HFC was recovered by service technicians in an individual container of less than 500 pounds gross refrigerant weight and delivered to a wholesaler or distributor, or delivered directly to an EPA-Certified reclaimer, documentation of the point of origin of the reclaimed HFC including:
  - Name and address of the service company, wholesaler or distributor that delivered the individual container of less than 500 pounds to the reclaimer;
  - The cylinder number, gross refrigerant weight, and net refrigerant weight of each container received by the EPA-certified reclaimer; and
  - Date(s) received by the EPA-certified reclaimer.

- For disposed aerosol products, documentation on the point of origin of the HFC including:

- Name and address of the entity that delivered the disposed aerosol products to the EPA-Certified reclaimer;
- The weight of the recovered HFC after processing by the EPA-certified reclaimer; and
- Date(s) received by the EPA-certified reclaimer.

- Tracking of the containers that are used for collection and transport to the reclaimer of the recovered HFC refrigerant (e.g. unique identification with serial number or barcode).
- Documentation on the type of HFC that is recovered from equipment or product and that is subsequently reclaimed.
- Documentation on the quantity of HFC refrigerant produced in the reclamation process, accounting for contaminants that are removed in the reclamation process.[13]
- Documentation that the same quantity of reclaimed HFC refrigerant (i.e. equal to the volume of HFC that was reclaimed during the reporting period) is transferred, sold, or returned to a refrigerant wholesaler, distributor, or end-user (either through direct sale, title transfer or return to an end user or through installation conducted via service technician).
- Documentation demonstrating that the reclaimer is an EPA-Certified reclaimer and reclaimed the refrigerant using equipment listed with the EPA, including:
  - The most recent equipment list provided to the EPA by the EPA Certified reclaimer; and
  - The physical address where the reclamation was conducted.
- Documentation showing that used HFC refrigerant processed by the EPA-Certified reclaimer is tested by an AHRI certified refrigerant testing laboratory to meet the AHRI 700-2015 Standard for Specification for Fluorocarbon Refrigerants.

5.2.1 Parameters Monitored

PARAMETER	$VR_{HFC,j,rp}$
UNITS	kg
DESCRIPTION	Total quantity of virgin HFC refrigerant j that would have been used to recharge equipment during the reporting period (kgs), derived from the quantity of monitored certified reclaimed HFC refrigerant that is documented according to the procedures in Section 3.1 and Section 5

[13] In any measurement of the quantity of refrigerant that involves weighing of a cylinder(s) (e.g., refrigerant recovered from equipment), the weight of the "empty" cylinder(s) (prior to filling with refrigerant) must be measured so that that any residual refrigerant (the cylinder "heel") is considered.

RELEVANT SECTION	4.1.1
RELEVANT EQUATION(S)	1
SOURCE OF DATA	Operating Records
MEASUREMENT FREQUENCY	Determined once for each project (which consists of only one reporting period).

APPENDIX A: BASELINE DATA INPUTS

A.1 RATE OF HFC RECLAMATION

Reclaimers in the United States are required to report to EPA the quantities of CFCs and HCFCs that they reclaim. Currently there are no reporting requirements for HFC reclamation. Because CFC production ended in 1996, reclaimed CFCs are essentially the only source of CFCs for CFC-based equipment still in use. Similarly, because HCFC-22 production is being phased out and will end in 2020, there is a strong incentive for system owners and service technicians to recover and re-use as much R-22 as possible to service equipment.

In contrast, there are no restrictions on production of HFCs, and because of the additional costs to recover, transport, and separate/process back to virgin purity levels[14] — unlike the strong incentive to reclaim CFCs and R-22 — there is currently little incentive for recovery, reclamation, and re-sale of HFCs. Thus, a conservative approach to estimate the amount of HFC refrigerant that is reclaimed in the baseline scenario is to use data from the United States EPA on R-22 reclamation, described below.

Table 5: Total reclaimed R-22 reported to EPA

Most recent data on the quantity of reclaimed R-22 in the U.S., as reported to the EPA.

YEAR	AMOUNT RECLAIMED IN POUNDS[15]
2010	7,985,289
2011	8,325,390
2012	9,401,446
2013	8,898,470

[14] http://ozone.unep.org/new_site/en/ozone_data_tools_reclaimation_facilities.php

[15] EPA (2014)

To calculate the R-22 reclaim rate (%) for a given year, the quantity of R-22 reclaimed is divided into the estimated quantity of R-22 being recovered from end-of-life equipment:

RR_{BL} = R-22 Reclaimed ÷ R-22 coming off-line

Based on data presented in an EPA report, for the most recent year (2013), it is estimated that 100 Million pounds of R-22 came "off-line":

- Estimated installed base of R-22 based refrigeration and air conditioning equipment contained 1.5 billion pounds of R-22 (ICF 2009; Tables A-1 and B-1)
- Assumed turnover rate of 7% per year on average (1/15 lifetime of equipment) (ICF, 2009; Table A-1)

The R-22 reclaim rate for 2013 is calculated as: **8.9 M ÷ 100 M = 8.9%**

Based on industry communications, the reclaim rate for HFC refrigerants is significantly lower than 8.9%. This is expected because R-22 production and import is being phased out and is tightly controlled under EPA's annual allocations. However, for purposes of this Methodology, a conservative assumption is made that the rate by which HFC refrigerants are reclaimed under the baseline scenario is the same (8.9%) as the R-22 reclaim rate based on the most recent data. As new data become available on R-22 reclamation, and eventually HFC reclamation, ACR will update this factor.

This Methodology also allows credits for use of HFCs that are recovered from discarded aerosol products and subsequently reclaimed for re-use as refrigerant. Since R-22 is not used as an aerosol propellant, the EPA data on R-22 reclamation would not reflect the baseline rate of reclamation of HFC aerosols. Industry information indicates that there may be very small quantities of HFCs in discarded medical aerosol products that are being recovered in the U.S. (e.g., less than a few thousand pounds per year) and that none of the non-medical aerosol products that are discarded in the U.S. are being managed at end-of-life such that none of the HFCs in those products are being recovered. Therefore, using the current reclamation rate of R-22 as a proxy for the baseline reclamation rate for HFCs that are recovered from aerosol products is an extremely conservative approach.

A.2 HFC REFRIGERANT EMISSION FACTORS

Under this Methodology, baseline emissions for reclaimed HFC refrigerant projects are estimated in reference to the emission loss rates of equipment into which virgin HFC refrigerants would have been installed. The calculation is based on the actual quantities of certified reclaimed HFC refrigerant that enter commerce through sale, transfer, or return to a refrigerant end-user or distributor. It would be difficult to track the exact equipment where the reclaimed

HFC refrigerant is ultimately used. Therefore, the baseline is defined for a specific HFC refrigerant by the weighted-average emission rate for the equipment where that refrigerant is typically used.

Some HFC refrigerants are used in predominantly single applications, e.g., R-404A in commercial multiplex refrigeration systems. In this example, the average emission rate used in this Methodology for R-404A would be the average emission leak rate for commercial refrigeration.

In contrast, other HFC refrigerants are used in a variety of applications, e.g., HFC-134a is used for automotive A/C, residential refrigerator-freezers, stand-alone commercial refrigerators, and large chillers. In this case, a weighted-average emission rate is calculated for the refrigerant based on its "market share" across the various end-uses (e.g., 30% of HFC-134a refrigerant is used for automotive A/C, 25% of HFC-134a refrigerant is used for residential refrigerator-freezers, etc.), multiplied by the average leak rates for those end-uses.

Table 8 presents average annual emission rates for the major refrigeration and air conditioning end-use categories, derived from two sources –the US EPA Vintaging Model and the 2006 IPCC Guidelines for National GHG Inventories. The EPA Vintaging Model outputs are publicly available (CAR, 2012; EPA, 2015). To be conservative, the values from the IPCC Guidelines are the low end of ranges presented in Table 7.9 of that report.

Table 9 presents the 10-year weighted-average leak rates incorporating the data in Table 8.[16]

Table 6: Emission Factors for Refrigeration and Air Conditioning Systems

REFRIGERANT SECTOR	SEGMENT	AVERAGE ANNUAL EMISSION RATE*
Domestic Refrigeration	Residential refrigerators and freezers	0.6%
Commercial or Retail Food Refrigeration	Equipment used to store and display chilled and frozen goods for commercial sale such as supermarkets, convenience stores, bakeries, and restaurants. This equipment includes centralized supermarket systems, remote condensing units, and stand-alone equipment	20% (all but stand-alone equipment) 8% (stand-alone equipment)

[16] 10-year emission rates are calculated from the annual emission rates using the following formula: 10 yr ER = 1-(1-Annual ER)^{10})

REFRIGERANT SECTOR	SEGMENT	AVERAGE ANNUAL EMISSION RATE*
	(e.g., beverage vending machines, stand-alone display cases).	
Cold Storage Warehouses		12.3-15%
Industrial Process Refrigeration	Chemical, pharmaceutical, petrochemical and manufacturing industries, industrial ice machines and ice rinks.	12.3-15%
Transport Refrigeration	Refrigerated truck trailers, railway freight cars, ship holds, and other shipping containers.	20.6-27.9%
Stationary Air Conditioning (including chillers)	Comfort cooling for homes and commercial buildings, including multi-family buildings, office buildings, hospitals, universities, shopping malls, airports, sports arenas.	2-11.8%
Mobile Air Conditioning	Automobiles and Trucks	18%**

* Unless otherwise noted, emission rates are from the US EPA Vintaging Model as reported in ICF (2009) and EPA (2015).

** Lowest value in range in Table 7.9 of the 2006 IPCC Guidelines.

Table 7: 10-Year Emission Rates for Individual HFC Refrigerants

REFRIGERANT	END-USE	DEPLOYMENT OF REFRIGERANT BY END-USE (%)	END-USE WEIGHTED EMISSION RATE (%/YEAR) *	10-YEAR EMISSION RATE (%)
HFC-134a	Mobile A/C	60%	18%	76%
	Commercial Refrigeration	5%	20%	
	Stand-Alone Commercial Refrigeration	15%	8%	
	Chillers	5%	6.5%	
	Domestic Refrigeration	15%	0.6%	
HFC-23	Industrial Process Refrigeration	85%	13.7%	74%
	Chillers	15%	6.5%	
HFC-32	Residential and Commercial A/C	85%	10.2%	64%
	Chillers	15%	6.5%	
R-404A	Commercial Refrigeration	80%	20%	84%
	Stand-alone Commercial Refrigeration	5%	8%	
	Industrial Process Refrigeration	15%	13.7%	
R-407A	Commercial Refrigeration	100%	20%	89%

REFRIGERANT	END-USE	DEPLOYMENT OF REFRIGERANT BY END-USE (%)	END-USE WEIGHTED EMISSION RATE (%/YEAR) *	10-YEAR EMISSION RATE (%)
R-407C	Residential and Commercial A/C	95%	10.2%	68%
	Commercial Refrigeration	5%	20%	
R-410A	Residential and Commercial A/C	100%	10.2%	66%
R-417C	Mobile A/C	100%	18%	86%
R-422B	Residential and Commercial A/C	95%	10.2%	68%
	Commercial Refrigeration	5%	20%	
R-422C	Commercial Refrigeration	100%	20%	89%
R-422D	Commercial Refrigeration	100%	20%	89%
R-507A	Commercial Refrigeration	100%	20%	89%
R-508B	Stand-Alone Commercial Refrigeration	100%	8%	57%

* Annual emission rates for specific refrigerant end-uses taken from Table 8. Where those emission rates are presented as ranges in Table 8, the midpoint of the range is used.

A.3 HFC AEROSOL EMISSION FACTOR

For projects conducted under this Methodology involving HFCs that are recovered from discarded aerosol products, and subsequently reclaimed for re-use as refrigerant, baseline emissions for reclaimed HFC refrigerant projects are estimated in reference to the emission loss rate of products in which virgin HFCs would have been used as aerosol propellants. The HFCs that are currently used in aerosol products are HFC-134a and HFC-152a, both of which could be re-used as refrigerants[17], and HFC-227ea, which is not used as a refrigerant.[18]

Unlike refrigeration and air conditioning equipment, which leak gradually under normal operations, aerosol products are designed to release their contents (including propellant) completely with each use. All HFCs used in aerosols are assumed to be emitted in the year of manufacture (EPA, 2015). The 10-year cumulative emission factor used in this Methodology for HFCs originating from aerosol products is 100%.

[17] In contrast to HFC-152a, HFC-134a is a commonly used refrigerant so the expectation is that a very large proportion of any HFC aerosols that will be recovered for re-use will be HFC-134a.

[18] In addition to its use as an aerosol propellant, HFC-227ea is also used in fire-fighting applications.

APPENDIX B: OTHER METHODOLOGY CONSIDERATIONS AND GUIDANCE

B.1 LIFECYCLE GHG REDUCTION OF CERTIFIED RECLAIMED REFRIGERANT

This Methodology provides the method to quantify GHG emission reductions over a 10-year "crediting period" associated with specific "project activities" within a specific project boundary, e.g., Company A uses X lbs of certified reclaimed HFC-404A in 2016 to re-charge a supermarket refrigeration system.

Another quantification approach is to measure the climate benefits of certified reclaimed HFC refrigerant over its full lifecycle. This approach is based on the fact that all refrigeration and A/C equipment leaks, and that in the absence of any incentive or requirement to destroy HFC refrigerants at equipment end-of-life, all HFC refrigerants are ultimately emitted. In other words, under current regulatory and economic conditions, the lifecycle of HFC refrigerants ends with release to the atmosphere, regardless of what equipment the refrigerants are used in, the annual leak rates of that equipment, how the equipment is serviced, and the lifetime of that equipment.

As described in this Methodology, using certified reclaimed HFC refrigerant displaces production of virgin refrigerant, and therefore, prevents the inevitable release of that virgin refrigerant to the atmosphere. To account for the fact that some amount of HFC refrigerant is being reclaimed under business as usual, the baseline rate of HFC reclamation cited in Section 3.1of this Methodology shall be applied.

Under this approach, the full lifecycle climate benefit of certified reclaimed HFC refrigerant is calculated by:

Equation 3

$$\mathbf{ER_y = \sum_i [Q_{HFC,Reclaimed,j} \times (1 - RR_{BL})] \times GWP_{HFC,j} \div 1000}$$

WHERE

ER_y	Emission reductions in year y (MT CO_2eq per year)
$Q_{HFC,Reclaimed,j}$	Total quantity of certified reclaimed HFC refrigerant j used to recharge equipment i in year y (kg per year).
RR_{BL}	Baseline Refrigerant Reclamation Rate (% per year)[19]
$GWP_{HFC,j}$	Global warming potential of refrigerant j used in the project (see Table 4)

B.2 BEST PRACTICES

Users of this Methodology should ensure that best practices for managing refrigerants are incorporated throughout their operations, and to the extent practicable, adopted by other companies in their supply chain or other network. This section focuses on two areas: (1) tracking refrigerants within the organization and (2) ensuring proper control of refrigerants off-site. For the second category, even though refrigerants may be under the control of an outside party, this section provides guidance to consider when selecting a contractor or other partner.

- If a system owner, facility operator, or other party that controls refrigeration or air conditioning operations (collectively referred to as the "organization") has refrigeration equipment or a cooling system that contains an operating charge of 50 lbs or more per circuit, the organization should have a refrigerant tracking system. A tracking system must enable the organization to quantify leaks, isolate leak sources, and manage and repair refrigerant leaks across multiple systems and facilities. The organization should use the tracking system to establish a benchmark against industry trends and set and meet leak reduction goals. The organization should set a goal in terms of maximum amount and rate of refrigerant leakage.
- Refrigerant tracking software should have the ability to view inventory in systems and storage, generate targeted compliance reports and track refrigerants or refrigerant assets (e.g., 1000 lbs of R-22 owned by Party A) across their lifespan, including use in equipment, recovery/processing/reclamation, and disposal/destruction. The tracking system should have the following minimum capabilities:
  - Record & track properties & location of refrigerants
  - Record & track properties & location of cylinders
  - Record & track properties & location of systems

[19] Percentage of refrigerant that would be reclaimed in the business-as-usual case, currently estimated to be 8.9% per year; see Appendix A.1.

- Record & track who owns each of the above assets wherever they are in the supply chain.
- Record & track when & who performed all maintenance/service events

- When refrigeration equipment reaches its end of life, or when equipment is serviced and evacuated, all refrigerant must be recovered and if either recycled or reclaimed, it must be done in conformance with EPA Section 608 requirements. Refrigerant should not simply be taken out and put back into another system (re-use) without removing impurities that can affect the performance of the equipment receiving the used refrigerant.
- Filling of the recovery cylinder should be done carefully by monitoring the mass of refrigerant added into the cylinder, thus the cylinder should be kept preferably on electronic balance throughout the entire procedure. Ensure that the cylinder does not overfill, that means the cylinder is not filled to more than 80% of its volume with liquid refrigerant. Similarly, the discharge pressure should also be monitored to ensure that the maximum allowable pressure of the recovery cylinder is never exceeded. After recovery has been completed, the recovery cylinder should be labelled with the type and mass of refrigerant it now contains; this information should be entered into the electronic tracking system.
- Refrigerant handlers must recover the existing refrigerant charge from the system into proper pressure-rated recovery cylinders as specified in AHRI Guideline K-2009 for Containers for Recovered Non-Flammable Fluorocarbon Refrigerants. Any refrigerant shipped must comply with all DOT regulations and be in DOT-approved cylinders. Cylinders must be weighed with scales that are calibrated annually at a minimum to ensure accuracy.
- For any refrigerants that are shipped offsite for reclamation, a monitoring system should be used that enables the project participants to track cylinders so its location can be viewed online.
- Refrigerants should be managed so that system owners can access information that shows the cylinder number, the location of the refrigerant, the quantity and overall status (reclaimed, needs to be reclaimed, etc.). Owners of refrigerant must be able to know the location of their cylinders at all times.

Used refrigerant must be reprocessed to at least the purity level specified in Appendix A to 40 CFR Part 82, Subpart F.4 Reclaimed refrigerant must be verified to meet AHRI-700 standards.[20]

[20] AHRI Standard 700, *Specifications for Fluorocarbon Refrigerants*. www.ahrinet.org

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THE DESTRUCTION OF OZONE DEPLETING SUBSTANCES AND HIGH-GWP FOAM

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

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ACRONYMS

A/C	Air conditioning
AHRI	Air-Conditioning, Heating and Refrigeration Institute
ANSI	American National Standards Institute
CAA	Clean Air Act
CEMS	Continuous Emission Monitoring System
CFC	Chlorofluorocarbon
CH_4	Methane
CO_2	Carbon dioxide
CPT	Comprehensive Performance Test
DOT	U.S. Department of Transportation
DRE	Destruction and removal efficiency
EPA	United States Environmental Protection Agency
FTIR	Fourier transform infrared spectroscopy
GWP	Global warming potential
HBFC	Hydrobromofluorocarbon
HBR	High Boiling Residue
HCFC	Hydrochlorofluorocarbon
HFC	Hydrofluorocarbon
HWC	Hazardous waste combustor
MT	Metric ton

NESHAP	National Emissions Standards for Hazardous Air Pollutants
NIST	National Institute of Standards and Technology
ODS	Ozone depleting substances
PU	Polyurethane
RCRA	Resource Conservation and Recovery Act
SSR	GHG Sources, GHG Sinks, and GHG Reservoirs
TEAP	Technology and Economic Assessment Panel to the Montreal Protocol Parties

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1 INTRODUCTION

1.1 PURPOSE

The purpose of the Methodology is to quantify greenhouse gas (GHG) emission reductions associated with the destruction of: 1) high global warming potential (GWP) ozone depleting substances (ODS) obtained from and destroyed within the U.S. that would have otherwise been released to the atmosphere; 2) high-GWP foam blowing agents that are extracted from insulation foam; and 3) insulation foam that contains blowing agent(s) with high GWP. This Methodology updates the CARB ODS Protocol to include additional sources of ODS used as refrigerant in air conditioning and refrigeration equipment, ODS in medical aerosol and fire suppression applications, and ODS and other high-GWP blowing agents in foam. Additionally, modifications have been made to emission factors and methods used to generate emission reductions for foam projects and to methods used for monitoring destruction events conducted at destruction facilities that are a part of an enclosed equipment de-manufacturing system.

2 ELIGIBLE ACTIVITIES: QUANTIFICATION METHODOLOGY

This Methodology defines a set of activities designed to reduce GHG emissions by the destruction of eligible ODS, high-GWP foam blowing agents, or high-GWP insulation foam at a single qualifying destruction facility.

2.1 ELIGIBLE DESTRUCTION FACILITIES

I. The end fate of the ODS, high-GWP foam blowing agent, or high-GWP insulation foam must be destruction at either:
   A. An approved HWC subject to the RCRA and with a RCRA permit for the ODS destruction facility stating an ODS destruction efficiency of at least 99.99%; or
   B. A transformation or destruction facility that meets or exceeds the Montreal Protocol's TEAP standards provided in the *Report of the Task Force on Destruction Technologies.*
      i. A facility must demonstrate DRE of 99.99% and emission levels consistent with the guidelines set forth in the TEAP report.
      ii. A facility must have been certified by a third party no more than three years prior to the offset project start date and must show that it maintains its operational status as stated in the certification.

II. A destruction facility must meet all applicable monitoring and operational requirements under CAA and NESHAP standards, as well as all applicable federal, state, and local laws that apply directly to ODS, high-GWP foam blowing agent, and high-GWP insulation foam destruction activities during the time the ODS, high-GWP foam blowing agent or high-GWP foam destruction occurs.

III. At the time of ODS, high-GWP foam blowing agent, or high-GWP insulation foam destruction, the destruction facility must have a valid Title V air permit, if applicable, and any other air or water permits required by local, state or federal law to destroy ODS, high-GWP foam blowing agent, and/or high-GWP insulation foam and document compliance with all monitoring and operational requirements that apply to ODS, high-GWP foam blowing agent, and high-GWP insulation foam destruction project activities.

IV. Any upsets or exceedances must be managed in accordance with an authorized SSMP.

2.2 ELIGIBLE ODS, HIGH-GWP FOAM BLOWING AGENTS AND HIGH-GWP INSULATION FOAM

I. ODS, high-GWP foam blowing agents and high-GWP insulation foam destroyed under this Methodology must be from one or more of the eligible sources listed in subchapters 2.2.1, 2.2.2, 2.2.3, or 2.2.4 of this Methodology.

II. Eligible ODS, high-GWP foam blowing agents, or high-GWP insulation foam may not be combined within the same container.

III. ODS produced exclusively for use as solvents or other applications not listed in Sections 2.2.1, 2.2.2, 2.2.3, or 2.2.4 are not eligible.

IV. A single offset project may incorporate ODS, high-GWP foam blowing agents, or high-GWP insulation foam obtained from one or more of the source categories listed in sub-chapters 2.2.1, 2.2.2, 2.2.3, or 2.2.4 of this Methodology.

V. Destruction activity must take place under one or more Certificates of Destruction.

VI. All the following conditions must be met for multiple Certificates of Destruction to be eligible as a single project:

   A. The project proponent is the same for all ODS, high-GWP foam blowing agents, or high-GWP insulation foam destroyed;

   B. All ODS, high-GWP foam blowing agents, or high-GWP insulation foam must be destroyed at the same eligible destruction facility; and

   C. The destruction activities must occur during one reporting period.

VII. A Certificate of Destruction may be used for only one offset project.

VIII. Each Certificate of Destruction must be issued by the qualifying destruction facility and must include the following information:

   A. Project Proponent;

   B. Destruction facility;

   C. Certificate of destruction ID number;

   D. If applicable, serial, tracking, or ID number of all containers for which ODS destruction occurred;

   E. If applicable, serial, tracking or ID number of all containers for which high-GWP insulation foam destruction occurred;

   F. If applicable, serial, tracking or ID number of all appliances from which high-GWP foam blowing agents are extracted and destroyed in an enclosed equipment de-manufacturing system;

G. For ODS, extracted high-GWP foam blowing agent, and high-GWP insulation foam in containers, mass and type of material destroyed from each container;
H. For high-GWP foam blowing agent extracted and destroyed in an enclosed equipment de-manufacturing system, mass of each high-GWP foam blowing agent destroyed.
I. Start and end destruction dates.

IX. The ODS destroyed may originate from a single source or from numerous sources.
X. The high-GWP foam blowing agents may originate from a single source or from numerous sources.
XI. The high-GWP insulation foam may originate from a single source or from numerous sources.
XII. The handling, recovery, and disposal of ODS refrigerants must be performed by technicians certified by the U.S. EPA under CAA, sections 608 and 609, as applicable. Technicians may only service refrigeration or air conditioning equipment they are certified to service. Technician name and certification type(s) must be retained as part of the documentation retention requirements of this Methodology.

2.2.1 ODS Refrigerant Sources

I. Eligible refrigerants must originate from equipment, systems, or other supplies in the United States. Imported refrigerant is not eligible under this Methodology.
II. Refrigerants from government inventories or stockpiles are only eligible if they are allowed to be sold into commercial markets for subsequent use and are not required to be destroyed or converted.
III. Only destruction of the following ODS refrigerants is eligible to generate ACR Emission Reduction Tonnes (ERTs) under this Methodology:
A. CFC-11;
B. CFC-12;
C. CFC-13;
D. CFC-113;
E. CFC-114;
F. CFC-115;
G. HCFC-22
IV. HCFC-22 must be recovered from operating equipment that is subsequently de-commissioned or otherwise permanently retired from service.
V. HCFC-22 obtained from stockpiles is not eligible under this Methodology.
VI. ODS extracted from a foam source for use in refrigeration equipment is not considered part of this source category, and must instead be considered as a high-GWP insulation foam source.

2.2.2 High-GWP Insulation Foam Sources[1]

I. Eligible high-GWP insulation foam must originate from appliance foam, building foam, or other foam. Imported foams are not eligible under this Methodology.

II. Only destruction of the following high-GWP insulation foam blowing agents is eligible to generate ACR ERTs under this Methodology:

   A. CFC-11;

   B. CFC-12;

   C. HCFC-22;

   D. HCFC-141b;

   E. HFC-134a;

   F. HFC-245fa.

III. To be eligible, the high-GWP blowing agent must be destroyed in one of three ways:

   A. If high-GWP blowing agent is extracted from insulation foam and subsequently destroyed at a separate destruction facility, the blowing agent must be extracted from the insulation foam under negative pressure and collected, stored, and transported in hermetically sealed containers;

   B. If high-GWP blowing agent is extracted from foam and destroyed within an enclosed equipment de-manufacturing system, the blowing agent must be extracted from the foam and destroyed under negative pressure; or

   C. If high-GWP insulation foam is destroyed, the intact foam (i.e., foam that is not shredded or compacted prior to destruction) must be separated from the application from which it originated (i.e. those applications cited in subchapter 2.2.2 I) and must be stored, transported, and destroyed in sealed containers (see section 6.6 I).

2.2.3 Medical Aerosol Sources

I. Eligible medical aerosols must:

   A. Originate from domestic U.S. stockpiles of ODS originally produced in the U.S. prior to January 1, 2012 under an essential use exemption; and

   B. Be eligible for sale for use in medical products that are listed as essential uses by the U.S. Food and Drug Administration.

II. Any medical aerosols destroyed prior to January 1, 2012 are not eligible for credits under this Methodology.

III. Only destruction of the following ODS medical aerosols is eligible to generate ACR ERTs under this Methodology:

[1] Inclusive of high-GWP blowing agents extracted from insulation foam.

A. CFC-11;
B. CFC-12;
C. CFC-114.

2.2.4 Fire Suppressant Sources

I. Eligible fire suppressants must originate from equipment or systems in the United States. Imported ODS fire suppressants are not eligible under this Methodology.
II. Only destruction of the following fire suppressants is eligible under this Methodology:
   A. Halon 1211;
   B. Halon 1301.
III. Halon 1301 originating in stockpiles is not eligible under this Methodology.

3 ELIGIBILITY

ODS and high-GWP insulation foam (intact foam or extracted blowing agents) offset projects must adhere to the eligibility requirements below as well as general ACR program requirements included in the ACR Standard.

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes to project activities. This Methodology may also be peri-odically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the Methodology.

3.1 GENERAL ELIGIBILITY REQUIREMENTS

I. Offset projects that use this Methodology must:
   A. Collect and destroy ODS, high-GWP foam blowing agents, or high-GWP insulation foam that would otherwise be emitted to the atmosphere;
   B. Destroy the recovered ODS, high-GWP foam blowing agents, or high-GWP insulation foam through an eligible end-use management option pursuant to subchapter 2.1 of this Methodology;
   C. Conform with the point of origin documentation requirements, as specified in chapter 6 of this Methodology; and
   D. Conform to the chain of custody documentation requirements, as specified in chapter 6 of this Methodology.

II. A project proponent that uses this Methodology must:
   A. Monitor SSRs within the GHG Assessment Boundary as delineated in chapter 4 pursuant to the requirements of chapter 6 in this Methodology;
   B. Quantify GHG emission reductions pursuant to chapter 5 of this Methodology;
   C. Prepare and submit a GHG Project Plan in accordance with ACR Standard requirements; and
   D. Obtain validation and verification services from an ANSI-accredited offset verification body approved by ACR.

3.2 LOCATION

I. Only projects located in the United States or its territories are eligible under this Methodology.

II. All ODS and high-GWP insulation foam must be obtained from equipment, systems, and other eligible supplies in the United States or its territories.
III. All ODS, high-GWP foam blowing agents, and high-GWP insulation foam must be destroyed within the United States or its territories.

3.3 ADDITIONALITY

Offset projects must meet the additionality requirements included below. Eligible offsets must be generated by projects that yield additional GHG reductions that exceed any GHG reductions otherwise required by law or regulation or any GHG reduction that would otherwise occur in a conservative business-as-usual scenario. These requirements are assessed through the Legal Requirement Test in subchapter 3.3.1 and the Performance Standard Evaluation in subchapter 3.3.2 of this Methodology.

3.3.1 Legal Requirement Test

I. Emission reductions achieved by a project using this Methodology must exceed those required by any law, regulation, or legally binding mandate.
II. The following legal requirement test applies to all ODS and high-GWP insulation foam projects:
    A. If no law, regulation, or legally binding mandate requires the destruction of ODS stocks, high-GWP foam blowing agent, or high-GWP insulation foam, all emission reductions resulting from the recovery and destruction of ODS and high-GWP insulation foam are considered to not be legally required, and therefore eligible for crediting under this Methodology.
    B. If any law, regulation, or legally binding mandate requires the destruction of ODS stocks, high-GWP foam blowing agent, or high-GWP insulation foam, only emission reductions resulting from the recovery and destruction of ODS, high-GWP foam blowing agent, and high-GWP insulation foam that are in excess of what is required to comply with those laws, regulations, and legally binding mandates are eligible for crediting under this Methodology.

3.3.2 Performance Standard Evaluation

I. Emission reductions achieved by a project using this Methodology must exceed those likely to occur in a conservative business-as-usual scenario.
II. The destruction of HCFC-22 refrigerant obtained from stockpiles or other sources other than recovered from refrigeration or air conditioning equipment is ineligible for crediting under this Methodology.

III. The destruction of halon 1301 obtained from stockpiles or sources other than those recovered from fire suppression equipment is ineligible for crediting under this Methodology.
IV. The performance standard evaluation is satisfied if the ODS or high-GWP insulation foam project activities meet the project definition and all other eligibility requirements in the Methodology.

3.4 START DATE

I. An offset project must meet the start date requirements set forth in the ACR Standard.
II. For this Methodology, the project start date is defined as the date on which the earliest destruction activity of a project commences, as documented on a Certificate of Destruction.
III. Offset project activities (i.e. collection of ODS or high-GWP insulation foam, transportation of ODS or high-GWP insulation foam, etc.) will occur prior to offset project commencement.

3.5 REPORTING PERIODS

I. An ODS or high-GWP insulation foam project can only have a single reporting period.
II. Multiple destruction events may be combined within a single reporting period subject to the requirements in subchapter 2.2 V of this Methodology.
III. The reporting period must not exceed 12 consecutive months. The project proponent may choose a reporting period shorter than 12 consecutive months.
IV. The project reporting period begins on the project start date.

3.6 CREDITING PERIODS

I. The project crediting period is the period of time over which emission reductions are quantified for the purpose of determining creditable GHG reductions.
II. The project crediting period for this Methodology is ten years.
III. The project crediting period begins on the project start date.

3.7 REGULATORY COMPLIANCE

I. An offset project must meet the regulatory compliance requirements set forth in the ACR Standard.

II. The regulatory compliance requirements for a project apply to the collection, recovery, storage, transportation, mixing, and destruction of ODS, high-GWP foam blowing agents, or high-GWP insulation foam, including disposal of the post-destruction waste products that are directly applicable to the destruction activities. The regulatory compliance requirements in this section apply to the incinerator and any other unit or operation at the destruction facility, directly related to the destruction activities, during the time destruction occurs.

Any instances of non-compliance resulting from administrative or other issues not related to the project (those specific activities stated in Section 3.7 II) shall not be considered in a determination of project-related regulatory compliance.

4 OFFSET PROJECT BOUNDARY: QUANTIFICATION METHODOLOGY

I. The GHG assessment boundary, or offset project boundary, delineates the SSRs that must be included or excluded when quantifying the net changes in emissions associated with the recovery and destruction ODS and high-GWP insulation foam.

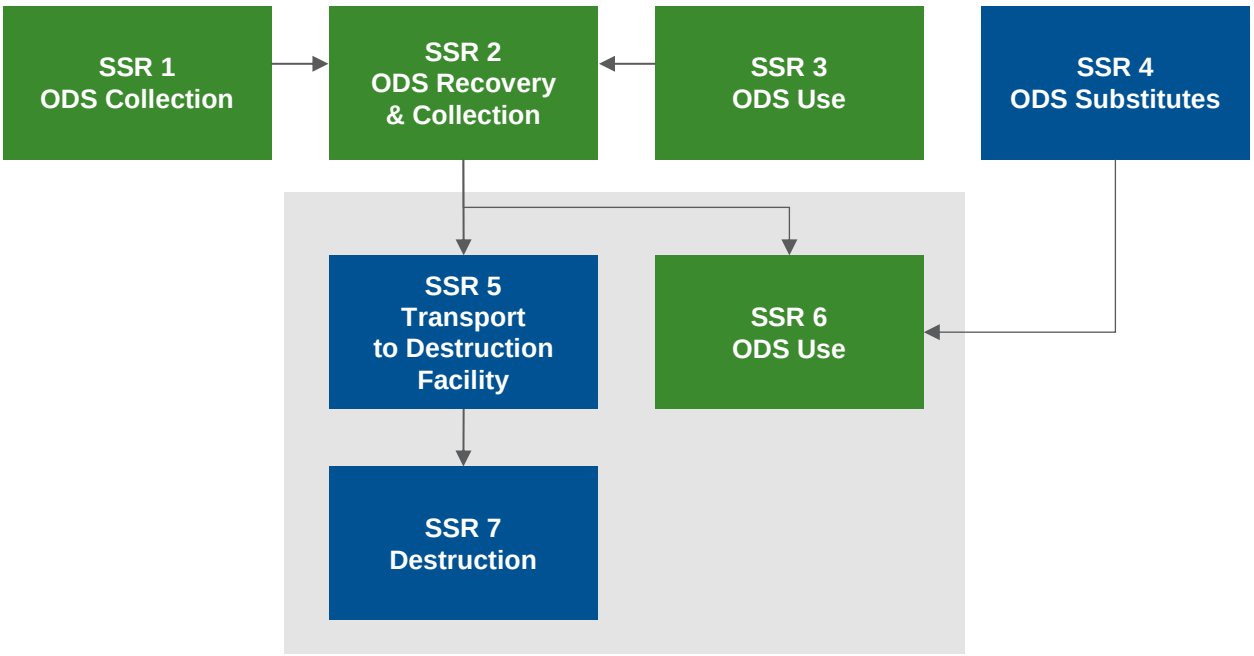
II. Figure 1 illustrates the GHG assessment boundary for refrigerant ODS, medical aerosol ODS, and fire suppressant ODS projects.

A. All SSRs inside the grey box are included and must be accounted for under this Methodology.

B. SSRs in green boxes are relevant to the baseline and project emissions.

C. SSRs in blue boxes are relevant only to project emissions.

Figure 1: Illustration of the Offset Project Boundary for Refrigerant, Medical Aerosol, and Fire Suppressant ODS Projects



III. Table 1 lists the SSRs for refrigerant, medical aerosol, and fire suppressant ODS projects indicating which gases are included or excluded from the offset project boundary.

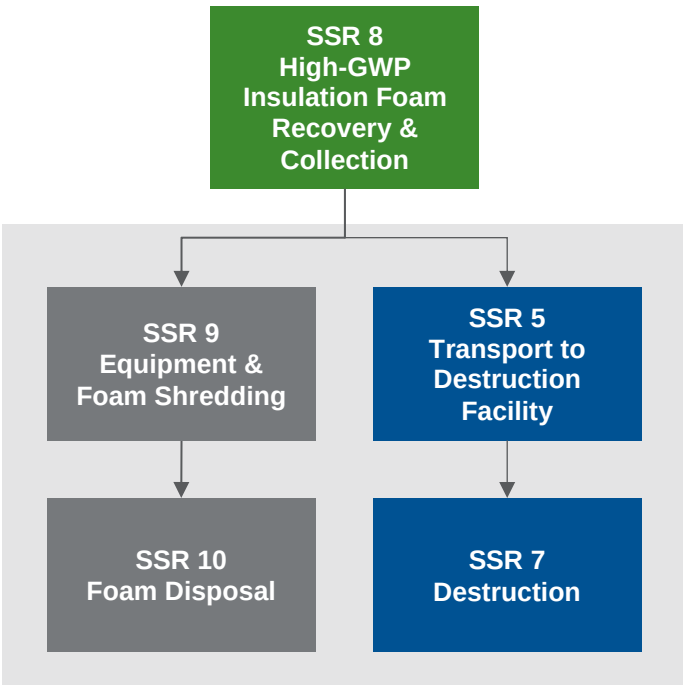
Table 1: List of Identified SSRs for Refrigerant, Medical Aerosol, and Fire Suppressant ODS Projects

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)
1 ODS Collection	Fossil fuel emissions from the collection and transport of ODS sources	CO_2	E
		CH_4	E
		N_2O	E
2 ODS Recovery and Collection	Emissions of ODS from the recovery and collection of ODS at end-of-life or servicing	ODS	E
	Fossil fuel emissions from the recovery and collection of refrigerant at end-of-life or servicing	CO_2	E
		CH_4	E
		N_2O	E
3 ODS Use	Emissions of ODS from equipment use, leaks, and servicing	ODS	E
	Fossil fuel emissions from the operation of refrigeration and A/C equipment and fire suppressant systems	CO_2	E
		CH_4	E
		N_2O	E
4 Substitute Refrigerant, Medical Aerosol, or Fire Suppressant Production	Emissions of substitute refrigerant, medical aerosols, or fire suppressants occurring during production	CO_2e	E
	Fossil fuel emissions from the production of substitute refrigerant, medical aerosols, or fire suppressants	CO_2	E
		CH_4	E
		N_2O	E

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)
5 Transport to Destruction Facility	Fossil fuel emissions from the vehicular transport of ODS from aggregation point to final destruction facility	CO_2	I
		CH_4	E
		N_2O	E
6 ODS Use	Emissions of ODS from use, leaks and servicing through continued operation of equipment	ODS	I
	Emissions of substitute from use, leaks and servicing through continued operation of equipment	CO_2e	I
	Indirect emissions from grid-delivered electricity	CO_2	E
		CH_4	E
		N_2O	E
7 Destruction	Emissions of ODS from incomplete destruction at destruction facility	ODS	I
	Emissions from the oxidation of carbon contained in destroyed ODS	CO_2	I
	Fossil fuel emissions from the destruction of ODS at destruction facility	CO_2	I
		CH_4	E
		N_2O	E
	Indirect emissions from the use of grid-delivered electricity	CO_2	I
		CH_4	E
		N_2O	E

IV. Figure 2 illustrates the GHG assessment boundary for high-GWP insulation foam projects.
   A. All SSRs inside the grey box are included and must be accounted for under this Methodology.
   B. SSRs in dark grey boxes are relevant only to baseline emissions.
   C. SSRs in blue boxes are relevant only to project emissions.
   D. SSRs in green boxes are relevant to the baseline and project emissions.

Figure 2: Illustration of the Offset Project Boundary for High-GWP Insulation Foam Projects



V. Table 2 lists the SSRs for high-GWP insulation foam projects indicating which gases are included or excluded from the offset project boundary.

Table 2: List of Identified SSRs for High-GWP Insulation Foam Projects

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)
5 ODS Collection	Fossil fuel emissions from the vehicular transport of high-GWP insulation foam or extracted blowing agent from aggregation point to final destruction facility	CO_2	I
		CH_4	E
		N_2O	E
7 Destruction	Emissions from incomplete destruction at destruction facility	ODS/HFC	I
	Emissions from the oxidation of carbon contained in destroyed foam or blowing agent	CO_2	I
	Fossil fuel emissions from the destruction of foam or blowing agent at destruction facility	CO_2	I
		CH_4	E
		N_2O	E
	Indirect emissions from the use of grid-delivered electricity	CO_2	I
		CH_4	E
		N_2O	E
8 High-GWP Insulation Foam Recovery and Collection	Emissions of ODS/HFC from demolition, deconstruction, or other damage to foam sources	ODS/HFC	E
	Fossil fuel emissions from demolition or deconstruction of foam sources	CO_2	E
		CH_4	
		N_2O	
	Fossil fuel emissions from the collection and transport of high-GWP foam sources	CO_2	E
		CH_4	

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)
		N_2O	
9 Equipment and Foam Shredding[2]	Emissions of ODS/HFC from the removal of foam from equipment for materials recovery, releasing ODS/HFC from foam	ODS/HFC	I
10 Foam Disposal	Emissions of ODS/HFC released from foam disposed of in landfills	ODS/HFC	I
	Fossil fuel emissions from the transport and placement of shredded foam waste in landfill	CO_2	E
		CH_4	E
		N_2O	E

[2] SSR 9 is only relevant to projects that manually remove foam in a non-enclosed equipment de-manufacturing system. For projects that destroy extracted high-GWP blowing agent from foam in an enclosed equipment de-manufacturing system, quantification of project emissions from foam removal is not required.

5 QUANTIFYING GHG EMISSION REDUCTIONS: QUANTIFICATION METHODOLOGY

I. GHG emission reductions from an ODS or high-GWP insulation foam[3] project are quantified by comparing actual project emissions to calculated project baseline emissions.
II. A project proponent must use the calculation methods provided in this methodology to determine baseline and project GHG emissions.
III. GHG emissions must be quantified using the GWP values in Tables 4-7.
IV. GHG emission reductions (ER) must be quantified by subtracting the project emissions (PE) from the baseline emissions (BE) using Equation 1.

Equation 1: Total Emission Reductions

$$\mathbf{ER_t = BE_t - PE_t}$$

WHERE		UNITS
$\mathrm{ER_t}$	Total quantity of GHG emission reductions during the reporting period	MT CO_2e
$\mathrm{BE_t}$	Total quantity of project baseline emissions during the reporting period	MT CO_2e
$\mathrm{PE_t}$	Total quantity of project emissions during the reporting period	MT CO_2e

5.1 QUANTIFYING BASELINE EMISSIONS

I. Baseline emissions (BE) must be estimated by using Equation 2 and by summing the baseline emissions for all SSRs identified as included in the baseline in Tables 1 and 2.

[3] Whether intact high-GWP insulation foam or blowing agent extracted from high-GWP insulation foam

Equation 2: Total Baseline Emissions

$$\mathbf{BE_t = BE_{refr} + BE_{foam} + BE_{aer} + BE_{fs}}$$

WHERE		UNITS
BE_t	Total quantity of project baseline emissions during the reporting period	MT CO_2e
BE_{refr}	Total quantity of project baseline emissions from refrigerant ODS	MT CO_2e
BE_{foam}	Total quantity of project baseline emissions from high-GWP blowing agent	MT CO_2e
BE_{aer}	Total quantity of project baseline emissions from medical aerosol ODS	MT CO_2e
BE_{fs}	Total quantity of project baseline emissions from fire suppressant ODS	MT CO_2e

II. Baseline emissions from refrigerant ODS (BE_{refr}) must be quantified using Equation 3.
III. BE_{refr} must include the estimated CO_2e emissions that would have occurred over the ten-year crediting period had the destroyed ODS been used in existing refrigeration or air conditioning equipment.
IV. The total mass of refrigerant ODS sent for destruction ($Q_{refr,i}$) includes eligible ODS and excludes the mass of HBR, moisture, ineligible ODS, and other ineligible material. Mass and composition of refrigerant ODS are determined per the procedures provided in Appendix C.
V. The GWP values for refrigerant ODS (GWP_i) must be taken from Table 4.
VI. The 10-year cumulative emission rate for refrigerant ODS ($ER_{refr,i}$) must be taken from Table 4.
VII. If the project did not destroy any refrigerant ODS, then $BE_{refr} = 0$.

Equation 3: Baseline Emissions from Refrigerant ODS

$$\mathbf{BE_{refr}} = \sum_{\mathbf{i}} (\mathbf{Q_{refr,i}} \times \mathbf{ER_{refr,i}} \times \mathbf{GWP_i})$$

WHERE		UNITS
BE_{refr}	Total quantity of refrigerant project baseline emissions during the reporting period	MT CO_2e
$Q_{refr,i}$	Total quantity of refrigerant ODS **i** sent for destruction by the offset_project	MT ODS
$ER_{refr,i}$	10-year cumulative emission rate of refrigerant ODS **i** (see Table 4)	%
GWP_i	Global warming potential of ODS **i** (see Table 4)	MT CO_2e/ MT ODS

VIII. Baseline emissions from high-GWP foam blowing agents (BE_{foam}) (blowing agent extracted from foam or intact foam) must be quantified using Equation 4.

IX. BE_{foam} must include the estimated CO_2e emissions that would have occurred over ten years as the result of foam disposal.

X. The 10-year cumulative emission rate for high-GWP blowing agents must be taken from Table 5.

XI. The mass and composition of extracted blowing agent from high-GWP foam (EBA_i) must be calculated per the procedures in Appendix C.

XII. The mass of intact high-GWP foam ($Q_{intf,\ i}$) must be calculated using the scales of the eligible destruction facility as specified in Appendix B.

XIII. The mass fraction of intact high-GWP blowing agent ($BA\%_{intf,\ i}$) must be calculated per Appendix B II.

XIV. If the project did not destroy any high-GWP blowing agent, then $BE_{foam} = 0$

Equation 4: Baseline Emissions from High-GWP Insulation Foam

$$\mathbf{BE_{foam}} = \sum_{\mathbf{i,j}} [(\mathbf{EBA_i} + \mathbf{BA_{intf,i}}) \times \mathbf{ER_{i,j}} \times \mathbf{GWP_i}]$$

WHERE		UNITS
BE_{foam}	Total quantity of high-GWP blowing agent project baseline emissions	MT CO_2e
EBA_i	Total quantity of high-GWP blowing agent **i** extracted from foam and destroyed (as determined through the procedures provided in Appendix C)	MT BA
$BA_{intf,i}$	Total quantity of high-GWP blowing agent **i** in intact foam sent for destruction (as determined through Equation 5)	MT BA
$ER_{i,j}$	10-year emission rate of high-GWP blowing agent **i** from application **j** (see Table 5)	%
GWP_i	Global warming potential of high GWP blowing agent **i** (see Table 5)	MT CO_2e/ MT BA

Equation 5: Quantity of high-GWP blowing agent from intact foam

$$\mathbf{BA_{intf,i}} = \mathbf{Q_{intf,i}} \times \mathbf{BA\%_{intf,i}}$$

WHERE		UNITS
$BA_{intf,i}$	Total quantity of high-GWP blowing agent **i** from intact foam sent for destruction	MT BA
$Q_{intf,i}$	Total mass of intact foam, **i**, with entrained high-GWP blowing agent sent for destruction (as determined through procedures in Appendix B I)	MT
$BA\%_{intf,i}$	Mass ratio of high-GWP blowing agent, **i**, entrained in intact foam (as determined per the procedures in Appendix B II)	% (0-1)

XV. Baseline emissions from medical aerosol ODS (BE_{aer}) must be quantified using Equation 6.

XVI. BE_{aer} must include the estimated CO_2e emissions that would have occurred over the ten-year crediting period had the destroyed ODS been used in medical aerosols.

XVII. The total mass of medical aerosol ODS sent for destruction ($Q_{aer,\,i}$) includes eligible ODS and excludes the mass of HBR, moisture, ineligible ODS, and other ineligible material. Mass and composition of medical aerosol ODS are determined per the procedures found in Appendix C.

XVIII. The GWP values for medical aerosol ODS (GWP_i) must be taken from Table 6.

XIX. The 10-year cumulative emission rate for medical aerosol ODS ($ER_{aer,\,i}$) must be taken from Table 6.

XX. If the project did not destroy any medical aerosol ODS, then $BE_{aer} = 0$.

Equation 6: Baseline Emissions from Medical Aerosol ODS

$$\mathbf{BE_{aer}} = \sum_{\mathbf{i}} \left(\mathbf{Q_{aer,i}} \times \mathbf{ER_{aer,i}} \times \mathbf{GWP_i} \right)$$

WHERE		UNITS
BE_{aer}	Total quantity of medical aerosol project baseline emissions during the reporting period	MT CO_2e
$Q_{aer,i}$	Total quantity of medical aerosol ODS **i** sent for destruction by the project	MT ODS
$ER_{aer,i}$	10-year cumulative emission rate of medical aerosol ODS **i** (see Table 6)	%
GWP_i	Global warming potential of ODS **i** (see Table 6)	MT CO_2e/ MT ODS

XXI. Baseline emissions from fire suppressant ODS (BE_{fs}) must be quantified using Equation 7.

XXII. BE_{fs} must include the estimated CO_2e emissions that would have occurred over the ten-year crediting period had the destroyed ODS been used in existing fire suppression equipment or systems.

XXIII. The total mass of fire suppressant ODS sent for destruction ($Q_{fs,i}$) includes eligible ODS and excludes the mass of HBR, moisture, ineligible ODS, and other ineligible material.

Mass and composition of fire suppressant ODS are determined per the procedures provided in Appendix C.

XXIV. The GWP values for fire suppressant ODS (GWP_i) must be taken from Table 7.

XXV. The 10-year cumulative emission rate for fire suppressant ODS ($ER_{fs,i}$) must be taken from Table 7.

XXVI. If the project did not destroy any fire suppressant ODS, then $BE_{fs} = 0$.

Equation 7: Baseline Emissions from Fire Suppressant ODS

$$BE_{fs} = \sum_{i} Q_{fs} \times ER_{fs,i} \times GWP_i$$

WHERE		UNITS
BE_{fs}	Total quantity of fire suppressant project baseline emissions during the reporting period	MT CO_2e
Q_{fs}	Total quantity of fire suppressant ODS i sent for destruction by the project	MT ODS
$ER_{fs,i}$	10-year cumulative emission rate of fire suppressant ODS i (see Table 7)	%
GWP_i	Global warming potential of ODS i (see Table 7)	MT CO_2e/ MT ODS

5.2 QUANTIFYING PROJECT EMISSIONS

I. Project emissions (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Tables 1 and 2 using Equation 8.

Equation 8: Total Project Emissions

$$PE_t = Sub_{refr} + Sub_{fs} + Sub_{aer} + Rem_f + Tr\&Dest$$

WHERE		UNITS
PE_t	Total quantity of project emissions during the reporting period	MT CO_2e

Sub_{refr}	Total GHG emissions from substitute refrigerant	MT CO_2e
Sub_{fs}	Total GHG emissions from substitute fire suppressant	MT CO_2e
Sub_{aer}	Total GHG emissions from substitute medical aerosol	MT CO_2e
Rem_f	Total GHG emissions from removal of high GWP foam in a non-enclosed equipment de-manufacturing system	MT CO_2e
Tr&Dest	Total GHG emissions from transportation and destruction of ODS and high-GWP insulation foam/blowing agents	MT CO_2e

II. Project emissions from substitute refrigerants (Sub_{refr}) must be quantified using Equation 9.

III. Sub_{refr} must include the estimated CO_2e emissions over a ten-year period from non-ODS substitute refrigerants that are used. The emission factors for substitute refrigerants in Table 4 must be used.

IV. The total mass of refrigerant ODS sent for destruction ($Q_{ref,i}$) excludes the mass of HBR, moisture, and ineligible ODS. Mass and composition of refrigerant ODS are determined per the procedures provided in Appendix C.

V. If the project did not destroy any refrigerant, then $Sub_{refr} = 0$.

Equation 9: Project Emissions from the Use of Non-ODS Refrigerants

$$\mathbf{Sub_{refr}} = \sum_{\mathbf{i}} \mathbf{Q_{ref,i}} \times \mathbf{SE_i}$$

WHERE		UNITS
$\mathbf{Sub_{refr}}$	Total quantity of refrigerant substitute emissions	MT CO_2e
$\mathbf{Q_{ref,i}}$	Total quantity of refrigerant $\mathbf{i}$ sent for destruction	MT ODS
$\mathbf{SE_i}$	Emission factor for substitute(s) for refrigerant $\mathbf{i}$, per Table 4	MT CO_2e/ MT ODS destroyed

VI. If high-GWP foam is manually removed in a non-enclosed equipment de-manufacturing system, project emissions from removal of the foam (Rem_f) must be quantified using Equation 10.

A. The default percentage of blowing agent that is lost when foam is removed from appliances in a non-enclosed manufacturing facility is 10% (Lfr).

VII. If the project did not destroy any high-GWP blowing agent, then $Rem_f = 0$.

Equation 10: Project Emissions from Removal of Foam in a Non-Enclosed Equipment De-Manufacturing System

$$\mathbf{Rem_f = (BE_{foam} \times Lfr)}$$

WHERE		UNITS
Rem_f	Total GHG emissions from removal of high GWP foam in a non-enclosed equipment de-manufacturing system	MT CO_2e
BE_{foam}	Total quantity of high-GWP blowing agent project baseline emissions (as determined through Equation 4)[4]	MT CO2e
Lfr	Default percentage of blowing agent that is lost in removal of foam from appliances in a non-enclosed equipment de-manufacturing system	10%

VIII. Project emissions from substitute medical aerosols (Sub_{aer}) must be quantified using Equation 11.

IX. Sub_{aer} must include the estimated CO_2e emissions over a ten-year period from non-ODS substitute medical aerosols that are used. The emission factors for substitute medical aerosols in Table 6 must be used.

X. The total mass of medical aerosol ODS sent for destruction ($Q_{aer,i}$) excludes the mass of HBR, moisture, and ineligible ODS. Mass and composition of medical aerosol ODS are determined per the procedures found in Appendix C.

XI. If the project did not destroy any medical aerosols, then $Sub_{aer} = 0$.

[4] Note that, for purposes of quantifying project foam removal emissions, project baseline emissions used in this equation shall only include the proportion of emissions associated with foam that is manually removed in a non-enclosed manufacturing facility.

Equation 11: Project Emissions from the Use of Non-ODS Medical Aerosols

$$\mathbf{Sub_{aer} = \sum_{i} (Q_{aer,i} \times SE_i)}$$

WHERE		UNITS
Sub_{aer}	Total quantity of medical aerosol substitute emissions	MT CO_2e
$Q_{aer,i}$	Total quantity of medical aerosol i sent for destruction	MT ODS
SE_i	Emission factor for substitute(s) medical aerosols i, per Table 6	MT CO_2e/ MT ODS destroyed

XII. Project emissions from substitute fire suppressants (Sub_{fs}) must be quantified using Equation 12.

XIII. Sub_{fs} must include the estimated CO2e emissions over a ten-year period from non-ODS substitute fire suppressants that are used. The emission factors for substitute fire suppressants in Table 7 must be used.

XIV. The total mass of fire suppressant ODS sent for destruction ($Q_{fs,i}$) excludes the mass of HBR, moisture, and ineligible ODS. Mass and composition of fire suppressant ODS are determined per the procedures provided in Appendix C.

XV. If the project did not destroy any fire suppressant, then Sub_{fs} = 0.

Equation 12: Project Emissions from the Use of Non-ODS Fire Suppressants

$$\mathbf{Sub_{fs} = \sum_{i} (Q_{fs,i} \times SE_i)}$$

WHERE		UNITS
Sub_{fs}	Total quantity of fire suppressant substitute emissions	MT CO_2e
$Q_{fs,i}$	Total quantity of fire suppressant i sent for destruction	MT ODS
SE_i	Emission factor for substitute(s) for fire suppressant i, per Table 7	MT CO_2e/ MT ODS destroyed

XVI. Project emission from the transportation and destruction of ODS and high-GWP insulation foam/blowing agent shall be quantified using default emission factors in Equation 13.

A. The default emission factor for ODS transportation and destruction is 7.5 MT CO_2e per MT ODS for refrigerant, medical aerosol, fire suppressant or blowing agent extracted from high-GWP foam.

B. The default emission factor for transportation and destruction is 75 MT CO2e per MT of high-GWP foam for intact foam projects.

C. Q_{ODS} and Q_{BA} include the mass of all eligible and ineligible ODS and high-GWP blowing agent, moisture, HBR, and other accompanying material.

Equation 13: Project Emissions from Transportation and Destruction Using the Default Emission Factors

$$\mathbf{Tr\&Dest = (Q_{ODS} \times EF) + (Q_{BA} \times EF) + (Q_{intf} \times EF)}$$

WHERE		UNITS
$Tr\&Dest$	Total GHG emissions from ODS and high-GWP insulation foam/blowing agent transportation and destruction, as calculated using default emission factors	MT CO_2e
Q_{ODS}	Total quantity of refrigerant, medical aerosol, and/or fire suppressant ODS sent for destruction in the project	MT ODS
Q_{BA}	Total quantity of high-GWP blowing agent extracted from insulation foam and sent for destruction in the project	MT BA
Q_{intf}	Total mass of intact foam with entrained high-GWP blowing agent sent for destruction	MT
EF	Default emission factor for transportation and destruction of ODS or High-GWP Blowing Agent foam (7.5 for refrigerant, medical aerosol, fire suppressant or extracted blowing agent projects, 75 for intact high-GWP foam projects)	MT CO_2e/ MT ODS/ MT BA or MT

5.3 ACCOUNTING FOR DISQUALIFIED ODS MATERIAL AND HIGH-GWP FOAM AFTER DESTRUCTION

ERTs may only be generated for the destruction of eligible ODS, high-GWP foam blowing agents, and high-GWP insulation foam that meet the point of origin and chain of custody requirements specified in chapter 6 of this Methodology. Any disqualified ODS, high-GWP foam blowing agents, or high-GWP insulation foam must be removed from baseline emission calculations using the following method to determine the mass and species of the disqualified ODS, high-GWP foam blowing agents, or high-GWP insulation foam:

I. The total mass of each container of disqualified ODS (from refrigerant, medical aerosol, or fire suppressant ODS or high-GWP blowing agent) or high-GWP insulation foam shall be considered as the original container when the ODS or high-GWP foam was acquired. Documentation of the acquired ODS, high-GWP blowing agent, or high-GWP insulation foam must identify the capacity of the disqualified ODS, high-GWP blowing agent or high-GWP insulation foam container or the entire destruction event is not eligible for crediting. If a container's capacity is labelled in volume rather than in mass, the densities in Table 8 must be used to convert the volume to mass.
   A. For refrigerant, medical aerosol, or fire suppressant ODS or high-GWP foam blowing agent: If converting between mass and volume, the ODS or blowing agent must be in a liquid state.

II. The species of each disqualified ODS or high-GWP blowing agent shall be the species with the highest GWP of the destruction event.

III. The determined mass of disqualified ODS or high-GWP blowing agent shall be subtracted from the total mass of that ODS or high-GWP blowing agent species destroyed in the project.
   A. The total mass of refrigerant ODS sent for destruction ($Q_{refr,i}$) shall be adjusted in Equation 3.
   B. The total quantity of blowing agent extracted from high-GWP foam and sent for destruction ($EBA_{,i}$) shall be adjusted in Equation 4.
   C. The total mass of high-GWP blowing agent from intact high-GWP foam sent for destruction ($BA_{intf,i}$) shall be adjusted in Equation 5.
   D. The total mass of medical aerosol ODS sent for destruction ($Q_{aer,i}$) shall be adjusted in Equation 6.
   E. The total mass of fire suppressant ODS sent for destruction ($Q_{fs,i}$) shall be adjusted in Equation 7.

5.4 CONVERSION FACTORS AND ROUNDING PRACTICES

I. For the purpose of this Methodology, 1 pound (lb) equals 0.45359 kilogram (Kg).
II. The following rounding practices shall be applied for the purpose of this Methodology:
   A. At least five significant digits shall be maintained.
   B. There shall be no rounding to the left side of the decimal.

6 MONITORING

6.1 GENERAL MONITORING REQUIREMENTS

I. The project proponent is responsible for monitoring all project activities to ensure compliance with this Methodology.

II. The point of origin of all ODS and high-GWP foam must be documented. The project proponent must collect and maintain documentation showing regulatory compliance back to all points of origin.

III. Documentation of the point of origin must be generated at the time of collection from the point of origin and must include all the following:

   A. Facility name and physical address;

   B. Point of origin zip code;

   C. Identification of any refrigeration or air conditioning equipment by serial number, if available, or description, location, and function, if serial number is unavailable (for refrigerant ODS quantities greater than 500 pounds that originate in equipment that is not processed at an enclosed equipment de-manufacturing facility); and

   D. Serial or ID number of containers used for storage and transport.

IV. For refrigerant ODS, medical aerosol ODS, and fire suppressant ODS, the project proponent must collect and maintain documentation on the chain of custody and ownership of the ODS beginning at the point of origin until destruction, including all the following:

   A. Names, addresses, and contact information of all entities buying and selling ODS for destruction; and

   B. The mass of ODS including ineligible ODS and contaminants, at each transaction.

V. For projects destroying refrigerant ODS sourced from government stockpiles or inventories, the project proponent must maintain documentation that the ODS could be sold into commercial markets, and that the ODS is not required to be destroyed or converted.

VI. For projects destroying medical aerosol ODS, the project proponent must maintain documentation that the ODS is eligible to be sold for use in a medical product that is listed as an essential use by the U.S. Food and Drug Administration.

VII. For projects recovering and destroying HCFC-22 refrigerant or Halon 1301 fire suppressant and that meet the point of origin determination requirements in Section 6.2 II B ii, the project proponent must obtain a signed attestation from a representative at the point of origin facility regarding the source of the HCFC-22 or Halon 1301. Specifically, this attestation must state whether the source equipment has been decommissioned or otherwise

permanently retired from service and the date of decommissioning or retirement. The attestation shall be supplied to the ACR and to the validation and verification body for assessment.

VIII. For intact high-GWP foam sources (i.e. those where blowing agent is not extracted prior to destruction), the project proponent must collect and maintain all the following information:

A. For intact high-GWP building and intact other foams:

i. Total quantity of foam from each foam type (i.e. differentiated by building and specific allowable other foams) that is the source of the high-GWP blowing agent in the project;

ii. Type and amount of blowing agent in the foam determined through procedures in Appendix BII; and

B. For intact appliance high-GWP foams:

i. Numbers of units containing high-GWP foam that are processed;

ii. Type and amount of blowing agent(s) in the foam, determined through the procedures in Appendix B II, as applicable.

IX. For refrigerant ODS, medical aerosol ODS, and fire suppressant ODS and extracted high-GWP foam blowing agent that is not destroyed in an enclosed equipment de-manufacturing process, the project proponent must collect and maintain all the following information from the composition and mass analysis:

A. Time and date of sample;

B. Name of project proponent;

C. Name of technician taking sample;

D. Employer of technician taking sample;

E. Volume of container from which sample was extracted;

F. Ambient air temperature at time of sampling; and

G. Chain of custody for each sample from the point of sampling to the AHRI-certified lab.

X. For refrigerant ODS, medical aerosol ODS, and fire suppressant ODS and extracted high-GWP foam blowing agent, the destruction facility must track continuously during the destruction process the following parameters and provide the data about these parameters to the project proponent. The project proponent must collect and maintain all the following information from the destruction facility:

A. The feed rate;

B. Operating temperature and pressure of the destruction unit during destruction;

C. Effluent discharges measured in terms of water and pH levels;

D. CEMS data on the emissions of carbon monoxide during destruction; and

E. If applicable, for an enclosed equipment de-manufacturing system:

i. Mass and composition of ODS and high-GWP blowing agent(s) entering the destruction unit,
ii. Time and date(s) of chemical analyses,
iii. Number of appliances that are de-manufactured in the system, and
iv. Date(s) appliances enter equipment de-manufacturing system.

XI. For intact high-GWP insulation foam, the destruction facility must track during the destruction process the following parameters and provide the data about these parameters to the project proponent. The project proponent must collect and maintain all the following information from the destruction facility:
A. Mass of high-GWP foam fed into the destruction unit;
B. Operating temperature and pressure of the destruction unit during foam destruction;
C. Effluent discharges measured in terms of water and pH levels; and
D. CEMS data on the emissions of carbon monoxide during foam destruction.

6.2 POINT OF ORIGIN DETERMINATION

I. The project proponent must collect and maintain data on the point of origin of each refrigerant ODS, medical aerosol ODS, or fire suppressant ODS, high-GWP foam blowing agent, and high-GWP insulation foam as part of tracking chain of custody. Data must be generated at the time of collection from the point of origin.
II. Point of origin is defined as follows:
A. For refrigerant ODS, medical aerosol ODS, or fire suppressant ODS which is stored as a stockpile for more than 24 months prior to acquisition by the project proponent:
i. The point of origin for stockpiled refrigerant ODS, medical aerosol ODS, or fire suppressant ODS is the location of the stockpile[5].
B. For refrigerant ODS, medical aerosol ODS, or fire suppressant ODS which is not part of a stockpile for at least 24 months prior to acquisition by the project proponent:
i. The point of origin for refrigerant ODS, medical aerosol ODS, or fire suppressant ODS with mass less than 500 pounds is the site at which greater than or equal to 500 pounds of ODS is aggregated.
ii. The point of origin for refrigerant ODS, medical aerosol ODS, or fire suppressant ODS with mass greater than or equal to 500 pounds is the site where the ODS is removed from service.
iii. The point of origin for refrigerant ODS recovered from appliances at an equipment de-manufacturing facility is the equipment de-manufacturing facility.

[5] Per Section 3.3.2, stockpiled HCFC-22 and Halon 1301 is ineligible for crediting.

C. For blowing agent extracted from high-GWP foam, the point of origin is the facility where the blowing agent is extracted.

D. For blowing agent in intact appliance or intact other high-GWP foam, the point of origin is the location at which the foam is removed.

E. For blowing agent in intact building high-GWP foam, the point of origin is the location at which the building high-GWP foam was taken.

III. For refrigerant ODS, medical aerosol ODS, or fire suppressant ODS, the following provisions also apply to point of origin determination:

A. Any location at which 500 pounds is reached in a single transaction or shipment is a point of origin; the 500 pounds does not need to be in a single container.

B. For each container included within the project, the mass of HBR, moisture, ineligible ODS, and other ineligible material shall be included to determine if the 500-pound threshold is reached.

C. If refrigeration or air conditioning equipment or fire suppression equipment containing at least 500 pounds of ODS is transported prior to the ODS being removed from the equipment, then the point of origin is the site at which the ODS was removed from the equipment.

D. When ODS is added to a single container which is part of a stockpile and a portion of the ODS is subsequently removed from the container, the ODS removed must be considered the ODS stored the longest (i.e., first- in, first-out method).

6.3 INSTRUMENT QA/QC

I. For a destruction facility that is not part of an enclosed equipment de-manufacturing system, the scales used to determine the mass of ODS, high-GWP foam blowing agent, or high-GWP insulation foam used in calculating emission reductions must be:

A. Inspected at least quarterly; and

B. Properly calibrated per the destruction facility's RCRA permit, or for non-RCRA facilities, calibrated at least quarterly to 5% or better accuracy. RCRA facilities that do not have calibration requirements defined in their RCRA permits must calibrate scales quarterly to 5% or better accuracy.

II. For a destruction facility that is part of an enclosed equipment de-manufacturing system, the following requirements apply:

A. FTIR must be used to determine the mass and composition of ODS or high-GWP blowing agent and:

i. No more than one day prior to the commencement of the destruction event, conduct a check for calibration accuracy using a gas of known quality:

a. This check must demonstrate that the FTIR equipment is accurate to within +/- 1% relative to the reference gas;

ii. Conduct and record a daily zero validation of the FTIR equipment output;

iii. No more than one day prior to the end of the destruction event, conduct a check for calibration accuracy using a gas of known quality:

a. This check must demonstrate that the FTIR equipment is accurate to within +/- 1% relative to the reference gas

iv. The FTIR equipment must be calibrated by the manufacturer or a certified calibration service per manufacturer's specifications or every 5 years, whichever is more frequent. Instruments are exempted from calibration requirements if the manufacturer's specifications state that no calibration is required.

v. If a check on the FTIR equipment reveals accuracy less than +/- 1% threshold (reading relative to the reference gas), corrective action such as calibration by the manufacturer or a certified service provider is required for the FTIR equipment.

vi. If the check on the FTIR equipment reveals accuracy less than +/- 1% threshold during the check stipulated in Section 6.3 II A i, the destruction event may not commence until corrective action is performed and a subsequent check reveals accuracy within a +/-1% threshold

vii. If the check on the FTIR equipment reveals accuracy less than +/- 1% of threshold during the check stipulated in Section 6.3 II A iii, the mass and composition data from the FTIR equipment must be scaled per the following procedure. These adjustments must be made for the entire period from the check required in Section 6.3 II A i through to the end of the reporting period.

a. The project proponent shall calculate total emission reductions using:

1. The monitored values without correction; and

2. The monitored values adjusted based on the calibration drift recorded at the time of the check as required in Section 6.3 II A iii.

b. The lower of the two emission reduction estimates shall be reported as the emission reductions claimed for the reporting period.

B. If a catalyst is used in the destruction process, maintenance procedures related to catalyst replacement, carbon filter cleaning or other system controls needed to ensure the required 99.99% destruction efficiency is maintained must be implemented in accordance with manufacturer's guidance and specifications.

6.4 DOCUMENT RETENTION

I. The project proponent is required to keep all documentation and information outlined in this methodology.

II. Information that must be retained by the project proponent includes:

A. All data inputs for the calculation of the offset project emission reductions, including all required sampled data;

B. Copies of all permits, Notices of Violations (NOVs), and any relevant administrative or legal consent orders dating back at least 3 years prior to the project commencement date;

C. Destruction facility monitoring and maintenance information (CEMS data, DRE documentation, scale readings, calibration procedures, calibration checks and daily zero validations (if applicable), manufacturer guidance pertaining to facility or technology maintenance, and permits);

D. Chain of custody and point of origin documentation; and

E. ODS and high-GWP blowing agent composition and mass determinations (i.e., from laboratory reports or other procedures included in this Methodology).

6.5 MONITORING PARAMETERS: QUANTIFICATION METHODOLOGY

The project proponent must monitor the parameters described in Table 3.

Table 3: Project Monitoring Parameters – Quantification Methodology

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		Legal Requirement Test	N/A	For each offset project		Must be monitored and determined for each project
		Mass of ODS (or ODS mixture) or HFC in each container	Mass of mixture	Per container	M	Must be determined for each container

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		Concentration of ODS (or ODS mixture) or HFC in each container	Mass ODS or HFC/ Mass of mixture	Per container	M	Must be determined for each container
		Mass of ODS or HFC destroyed in an enclosed equipment demanufacturing system	Mass of mixture	Continuous	M	Readings taken and recorded every two minutes
		Concentration of ODS or HFC destroyed in an enclosed equipment de-manufacturing system	Concentration of ODS or HFC	Continuous	M	Readings taken and recorded every two minutes
		Mass of building foam used as source of ODS and high GWP blowing agent	Mass of building foam	For each offset project	M	Must be monitored for each project
1	ER_t	Total quantity of GHG emission reductions during the reporting period	MT CO_2e	For each offset project	C	
1 2	BE_t	Total quantity of baseline emissions during the reporting period	MT CO_2e	For each offset project	C	

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
1 8	PE_t	Total quantity of project emissions during the reporting period	MT CO_2e	For each offset project	C	
2 3	BE_{refr}	Total quantity of baseline emissions from refrigerant ODS	MT CO_2e	For each offset project	C	
2 4 10	BE_{foam}	Total quantity of baseline emissions from high-GWP blowing agent	MT CO_2e	For each offset project	C	
2 6	BE_{aer}	Total quantity of medical aerosol ODS baseline emissions	MT CO_2e	For each offset project	C	
2 7	BE_{fs}	Total quantity of fire suppressant ODS baseline emissions	MT CO_2e	For each offset project	C	
3 9	$Q_{refr,i}$	Total quantity of refrigerant ODS *i* sent for destruction	MT ODS	For each offset project	M	
3	$ER_{refr,i}$	10-year cumulative emission rate of refrigerant ODS *i*	0 - 1.0	N/A	R	See Table 4
3 4 6	GWP_i	Global warming potential of ODS or HFC *i*	MT CO_2e/ MT	N/A	R	See Tables 4-7

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
7			ODS or MT BA			
4	$EBA_{,i}$	Total quantity of high-GWP blowing agent *i* extracted from foam and destroyed	MT BA	For each offset project	C	
4 5	$BA_{intf,i}$	Total quantity of high-GWP blowing agent *i* in intact foam sent for destruction	MT BA	For each offset project	C	
4	$ER_{i,j}$	10-year emission rate of high-GWP blowing agent *i* from application *j*	% (0-1)	N/A	R	See Table 5
5	$Q_{intf,i}$	Total mass of intact foam, *i*, with entrained high-GWP blowing agent sent for destruction	MT	For each offset project	M	
5	$BA\%_{intf,i}$	Mass ratio of high-GWP blowing agent, *i*, entrained in intact foam	% (0-1)	For each offset project	M	
6 11	$Q_{aer,i}$	Total quantity of medical aerosol ODS, *i*, sent for destruction	MT ODS	For each offset project	M	

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
6	$ER_{aer,i}$	10-year cumulative emission rate of medical aerosol ODS *i*	0 - 1.0	N/A	R	See Table 6
7 12	$Q_{fs,i}$	Total quantity of fire suppressant ODS, *i*, sent for destruction	MT ODS	For each offset project	M	
7	$ER_{fs,i}$	10-year cumulative emission rate of fire suppressant ODS *i*	0 - 1.0	N/A	R	See Table 7
8 9	Sub_{refr}	Total GHG emissions from substitute refrigerant	MT CO_2e	For each offset project	C	
8 10	Rem_f	Total quantity of high-GWP blowing agent project baseline emissions from destruction of intact foam manually removed in a non-enclosed equipment demanufacturing system	MT CO_2e	For each offset project	C	
10	Lfr	Default percentage of blowing agent that is lost in manual removal of intact foam in a non-	% (0-1)	For each offset project	R	Equal to 10% for foam removed in a non-enclosed equipment de-manufacturing system

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		enclosed equipment de-manufacturing system				
8 11	Sub_{aer}	Total GHG emissions from substitute medical aerosols	MT CO_2e	For each offset project	C	
8 11	Sub_{fs}	Total GHG emissions from substitute fire suppressant	MT CO_2e	For each offset project	C	
8 13	Tr&Dest	Total GHG emissions from ODS and high-GWP insulation foam/blowing agent transportation and destruction	MT CO_2e	For each offset project	C	
9 11 12	SE_i	Emission factor for substitute emissions of refrigerant, medical aerosol, or fire suppressant, *i*	MT CO_2e/ MT ODS destroyed	Per container	R	See Tables 4, 6, 7
13	Q_{ODS}	Total quantity of refrigerant, medical aerosol and/or fire suppressant ODS sent for destruction	MT ODS	For each offset project	M/C	

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
13	Q_{BA}	Total quantity of high-GWP blowing agent extracted from insulation foam and sent for destruction in the project	MT BA	For each offset project	M/C	
13	Q_{intf}	Total mass of intact foam, *i*, with entrained high-GWP blowing agent sent for destruction	MT	For each offset project	M/C	
13	EF	Default emission factor for transportation and destruction of ODS or High-GWP Blowing Agent foam	MT CO_2e/ MT ODS/ MT BA or MT	N/A	R	Equal to 7.5 MT CO_2e per MT for refrigerant, medical aerosol, or fire suppressant projects and blowing agent extracted from high-GWP foam Equal to 75 MT CO_2e per MT for intact foam projects

6.6 OTHER MONITORING REQUIREMENTS: QUANTIFICATION METHODOLOGY

This subchapter provides monitoring requirements in addition to the general requirements in subchapter 6.1.

I. When transporting intact high-GWP insulation foam, all recovered foam pieces must be placed in air-tight and water-tight storage until arrival at the destruction facility.

II. Projects using this Methodology to quantify emission reductions from extracted high-GWP foam blowing agent must meet all the following requirements:

   A. The blowing agent must be extracted from the foam to a concentrated form prior to destruction.

   B. The extraction must occur under negative pressure.

   C. If the recovered blowing agent is not destroyed in an enclosed equipment de-manufacturing system, the recovered blowing agent must be collected, stored, and transported in containers meeting DOT standards for refrigerants and analyzed prior to destruction as specified in Appendix C.

   D. The processes, training, QA/QC, and management systems relevant to the collection, storage, and transport of the blowing agent must be documented.

   E. If the recovered blowing agent is destroyed in a destruction unit that is within an enclosed equipment de-manufacturing system, the blowing agent must be analyzed prior to destruction as specified in Appendix C.

III. Projects destroying high-GWP blowing agent from intact foam must follow the procedures in Appendix B. The project proponent must collect and maintain documentation showing conformance with the procedures in Appendix B.

IV. Projects destroying refrigerant ODS, medical aerosol ODS, fire suppressant ODS, or extracted high-GWP foam blowing agent must follow the procedures in Appendix C. The project proponent must collect and maintain information showing conformance with the procedures in Appendix C.

7 VERIFICATION REQUIREMENTS

I. See the ACR Standard for guidance on project validation and verification requirements.

II. An ODS or high-GWP insulation foam offset project requires only one site visit regardless of the number of destruction events within that reporting period.

III. For the purpose of this Methodology, the site visit must include a visit to the destruction facility. The site visit may also include a visit to the project proponent's office(s) where all project-related documents and data were produced, managed, and retained. The site visit may also include a visit to any facility in the chain of custody, such as an aggregation facility or other point of origin.

DEFINITIONS

If not explicitly defined here, the current definitions in the most recent version of the American Carbon Registry (ACR) Standard apply.

Aggregation	The grouping together of multiple containers of ODS, high-GWP foam blowing agents, or high-GWP insulation foam into a single shipment or single container. Aggregation does not require the collected ODS to be combined into a single container. Multiple containers shipped together are considered an aggregate.
Appliance Foam	Insulation foam in domestic appliances such as refrigerators and freezers, water heaters, and in commercial appliances such as refrigerator display cases and vending machines.
Building Foam	Insulation foam used in roofing, flooring, or walls.
Certificate of Destruction	An official document provided by the destruction facility certifying the date, mass, and species of ODS or high-GWP foam blowing agents destroyed.
Container	An air-tight and water-tight unit for storing or transporting ODS, high-GWP foam blowing agents, or high-GWP insulation foam material without leakage or escape. Containers used in transporting project material must comply with all applicable U.S. Department of Transportation (DOT) requirements.
Destruction	The destruction of ODS, high-GWP foam blowing agents, or high-GWP insulation foam by qualified destruction, transformation or conversion plants achieving greater than 99.99% destruction and removal efficiency (DRE), so that the destroyed ODS, high-GWP foam blowing agents, or high-GWP insulation foam are not emitted to the atmosphere. Destruction may be performed using any technology, including transformation, that results in the complete breakdown of ODS, high-GWP foam blowing agents, or high-GWP insulation foam into a waste product, a usable by-product, or end product.
Destruction facility	A facility that destroys, transforms, or converts ODS, high-GWP foam blowing agents, or high-GWP insulation foam and conforms with the description in either subchapter 2.1 I A or 2.1 I B in this Methodology.

Disqualified ODS, high-GWP foam blowing agents, or high-GWP insulation foam	ODS, high-GWP foam blowing agents, or high-GWP insulation foam that does not conform, or cannot be determined to conform, to the point of origin or chain of custody documentation requirements specified in chapter 6 of this Methodology and must be removed from baseline emission calculations pursuant to subchapter 5.3 in this Methodology.
Eligible ODS, high-GWP foam blowing agents, or high-GWP insulation foam	Those ODS, high-GWP foam blowing agents, or high-GWP insulation foam included in subchapter 2.2.1., 2.2.2, 2.2.3 and 2.2.4 in this Methodology.
Emission rate	The rate at which refrigerant, fire suppressant, medical aerosol, or foam blowing agent is released to the atmosphere.
Enclosed equipment de-manufacturing system	A system involving the disassembly and recycling of refrigerators and other appliances in which the cabinet, including insulation foam, is shredded and materials are recovered, measured, and destroyed in one or more enclosed, self-contained unit or units operating under negative pressure.
Essential Use Exemption	An exception, granted by the Parties to the Montreal Protocol, for continued production of medical aerosol ODS after the production prohibition for ODS used in other applications.
Fire suppression equipment/system	The equipment or system employed to control and extinguish fires used in any sector (including commercial, industrial, or residential).
Halons	A class of ODS that are powerful greenhouse gases and that contribute significantly to stratospheric ozone depletion. These substances are used in various fire suppression equipment and systems.
High-GWP Foam Blowing Agent	ODS or HFC entrained in insulation foam that was used in manufacture of the foam to provide insulation, structural and other performance properties. When reclaimed, ODS or HFC blowing agents have identical chemical properties as ODS or HFC refrigerants and may be sold and used as refrigerants. Unless they are reclaimed to virgin specifications, they cannot be sold on the market.

Ineligible ODS	Those ODS, high-GWP foam blowing agents, or high-GWP insulation foam not included in subchapter 2.2.1., 2.2.2, 2.2.3 and 2.2.4 in this Methodology.
Intact foam	Insulation foam that is not shredded or compacted prior to destruction.
Medical aerosol	The propellant used to dispense medication from a self-pressurized container. Certain ODS species have been used as medical aerosols.
Metered dose inhaler (MDI)	A device that delivers a specific amount of medication to the lungs, used to treat asthma and other respiratory diseases.
Mixed ODS or high-GWP foam blowing agent	Less than or equal to 90% composition of a single ODS or high-GWP foam blowing agent species.
Non-enclosed equipment de-manufacturing system	A system in which insulation foam in refrigerators and other appliances is removed manually in an open space that is not under negative pressure.
Non-mixed ODS or high-GWP foam blowing age	Greater than 90% composition of a single ODS or high-GWP foam blowing agent species.
Other Foam	Insulation foam used in refrigerated transportation, marine applications (such as boats and buoys), walk-in cooling units, and pipe-in-pipe/preformed pipe applications.
Ozone Depleting Substances (ODS)	Substances known to deplete the stratospheric ozone layer. The ODS controlled under the Montreal Protocol and its Amendments are chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), halons, methyl bromide (CH3Br), carbon tetrachloride (CCl4), methyl chloroform (CH3CCl3), hydrobromofluorocarbons (HBFC) and bromochloromethane (CHBrCl).
ODS or high-GWP foam blowing agent species	Any individual type of ODS or high-GWP foam blowing agent (e.g., CFC-11, CFC-113, HCFC-22, HFC-134a, etc.).

Refrigeration or air conditioning equipment	A refrigeration or air conditioning appliance or system used in any sector (including commercial, industrial, or residential).
Startup, shutdown, and malfunction plan (SSMP)	A plan, as specified under 40 CFR 63.1206, that includes a description of potential causes of malfunctions, including releases from emergency safety vents, that may result in significant releases of hazardous air pollutants, and actions the source is taking to minimize the frequency and severity of those malfunctions.
Stockpile	ODS stored for future use or disposal in bulk quantities at a single facility. The ODS may be stored in multiple containers or a single container.
Substitute refrigerant, medical aerosol, or fire suppressant	Those refrigerants, medical aerosols, or fire suppressants that will be used to fulfill the function that would have been filled by the destroyed ODS refrigerants, medical aerosols, or fire suppressants. These refrigerants, medical aerosols, or fire suppressants may be drop-in replacements or may be used in new equipment or devices that fulfill the same market function.
Substitute emissions	GHG emitted from the use of substitute refrigerants, medical aerosols, or fire suppressants in technologies that are used to replace the ODS destroyed in a project.
Transformation or Conversion	The breakdown of a substance into a waste product, a usable by-product, or end-product.

APPENDIX A: EMISSION FACTOR TABLES – QUANTIFICATION METHODOLOGY

Table 4: Parameters for ODS Refrigerants

ODS	100-YR GLOBAL WARMING POTENTIAL (MT CO_2E/MT ODS) (GWP_I)	10-YEAR CUMULATIVE EMISSION RATE (%/10 YEARS) ($ER_{REFR,I}$)	SUBSTITUTE EMISSIONS (MT CO_2E/MT ODS) (SE_I)
CFC-11	4,750	89%	223
CFC-12	10,900	95%	686
CFC-13	14,400	61%	7,144
CFC-113	6,130	89%	220
CFC-114	10,000	78%	659
CFC-115	7,370	61%	1,139
HCFC-22	1,810	72%	389

Table 5: Parameters for High-GWP Foam Blowing Agents

HIGH-GWP BLOWING AGENT	100-YR GLOBAL WARMING POTENTIAL (MT CO_2E/MT ODS OR BA) (GWP_I)	APPLIANCE HIGH-GWP BLOWING AGENT 10-YEAR EMISSION RATE ($ER_{I,J}$)	BUILDING HIGH-GWP BLOWING AGENT 10-YEAR EMISSION RATE ($ER_{I,J}$)	"OTHER FOAM" HIGH-GWP BLOWING AGENT 10-YEAR EMISSION RATE ($ER_{I,J}$)
CFC-11	4,750	70%	88%	88%
CFC-12	10,900	n/a	88%	88%
HCFC-22	1,810	69%	87%	88%
HCFC-141b	725	69%	87%	88%
HFC-134a	1,430	70%	88%	88%
HFC-245fa	1,030	70%	88%	89%

Table 6: Parameters for ODS Medical Aerosols

ODS	100-YR GLOBAL WARMING POTENTIAL (MT CO_2E/MT ODS) (GWP_I)	10-YEAR CUMULATIVE EMISSION RATE (%/10 YEARS) ($ER_{AER,I}$)	SUBSTITUTE EMISSIONS (MT CO_2E/MT ODS) (SE_I)
CFC-11	4,750	100%	152
CFC-12	10,900	100%	
CFC-114	10,000	100%	

Table 7: Parameters for ODS Fire Suppressants

ODS	100-YR GLOBAL WARMING POTENTIAL (MT CO_2E/MT ODS) (GWP_I)	10-YEAR CUMULATIVE EMISSION RATE (%/10 YEARS) ($ER_{FS,I}$)	SUBSTITUTE EMISSIONS (MT CO_2E/MT ODS) (SE_I)
Halon 1211	1,890	46%	3
Halon 1301	7,140	57%	254

Table 8: ODS Carbon Ratio and Density

ODS	CARBON RATIO (CR_I)	DENSITY (G/CM^3)
CFC-11	12/137	1.494
CFC-12	12/121	1.486
CFC-13	12/104	1.526
CFC-113	24/187	1.560
CFC-114	24/171	1.455
CFC-115	24/154	1.568
HCFC-22	12/87	3.66
HCFC-141b	24/117	1.25
Halon 1211	12/165	1.8
Halon 1301	12/149	1.54
HFC-134a	12/90	4.25
HFC-245fa	12/134	5.84

APPENDIX B: MASS AND COMPOSITION FROM INTACT HIGH-GWP FOAM PROJECTS – QUANTIFICATION METHODOLOGY

I. Prior to destruction, the precise mass and composition of intact high-GWP foam must be determined following the procedures described in this appendix.
   A. The foam's mass shall be determined on scales at the destruction facility. The scales must be calibrated at least quarterly with a demonstrated +/- 5% or better accuracy.
   B. Prior to determining building foam mass, any construction debris (e.g., wood, metal, glass) or any other non-foam material shall be separated from the foam.

II. To determine the composition and mass ratio of the high-GWP foam blowing agent(s) present in the intact foam, the following sampling requirements apply:
   A. For foams removed from buildings, at least two samples per building surface (e.g., wall, roof) must be taken;
   B. For foams removed from walk-in coolers or refrigerated transportation, one sample from each unit must be taken;
   C. For foams removed from pipes or marine applications, one sample must be taken from one unit from which foam will be taken for purposes of destruction (i.e. for projects that will aggregate multiple pipe sections or multiple units from marine sources such as buoys, one sample is required for each source type).
   D. The samples must conform to all the following requirements:
      i. Each sample must be at least 2 inches in length, 2 inches in width, and 2 inches thick;
      ii. For storage and transport, each sample must be placed and sealed in a separate air-tight and water-tight container that is at least 2 millimeters thick;
      iii. The analysis of high-GWP foam blowing agent content and mass ratio shall be performed at an independent laboratory unaffiliated with the project proponent. The analysis shall be done using one of the two following methods: (1) ASTM Method D 7132-14 Standard Test Method for Determination of Retained Blowing Agent in Extruded Polystyrene Foam or (2) the heating method to extract ODS blowing agent from the foam samples described in Scheutz *et al*. (2007). The Scheutz method must include all the following steps:

a. Each sample shall be prepared to a thickness no greater than 1 cm, placed in a 1123 mL glass bottle, weighed using a calibrated scale[6], and sealed with Teflon-coated septa and aluminum caps;

b. To release the high-GWP blowing agent from the foam, the samples must be incubated in an oven for 48 hours at 140 degrees C;

c. When cooled to room temperature, gas samples must be redrawn from the headspace and analyzed by gas chromatography[7];

d. The lids must be removed after analysis, and the headspace must be flushed with atmospheric air for approximately 5 minutes using a compressor. Afterwards, septa and caps must be replaced and the bottles subjected to a second 48-hr heating step to drive out the remaining high-GWP blowing agent from the sampled foam; and

e. When cooled down to room temperature after the second heating step, gas samples must be redrawn from the headspace and analyzed by gas chromatography[8].

E. The mass of high-GWP blowing agent(s) recovered shall then be divided by the total mass of the initial foam samples prior to analysis to determine the mass ratio of each high-GWP foam blowing agent present; and

F. For foams removed from buildings, the results from all samples from a single building shall be averaged to determine the mass fraction of blowing agent in foam ($BA\%_{intf,i}$) used in Equation 5.

[6] The scale must be calibrated at least quarterly with a demonstrated +/- 1% or better accuracy

[7] Room temperature is defined as a range between 20 and 25 degrees Celsius. Room temperature shall be recorded and documented at time of sampling.

APPENDIX C: MASS AND COMPOSITION FROM REFRIGERANT, MEDICAL AEROSOL, FIRE SUPPRESSANT AND EXTRACTED HIGH-GWP FOAM BLOWING AGENT PROJECTS – QUANTIFICATION METHODOLOGY

Prior to destruction, the precise mass and composition of ODS refrigerant, ODS medical aerosol, ODS fire suppression agent, and extracted high-GWP blowing agent must be determined.

I. For ODS and high-GWP blowing agent extracted into containers prior to destruction, the following analysis must be conducted:
   A. Mass must be determined by individually measuring the mass of each container first when it is full prior to destruction and then after destruction is complete. The mass of ODS or high-GWP blowing agent and any contaminants is equal to the difference between the full and empty mass, as measured. To be eligible to receive ERTs, all the following requirements must be met when weighing the containers:
      i. A single scale conforming with the requirements in (subchapter 6.3) of this Methodology must be used for generating both the full and empty mass tickets at the destruction facility;
      ii. The full mass must be measured no more than 48 hours prior to commencement of destruction per the CEMS data, if available, or the Certificate of Destruction;
      iii. The empty mass must be measured no more than 48 hours after the conclusion of destruction per the CEMS data, if available, or, the Certificate of Destruction; and
      iv. Each single compartment, cylinder, drum, or any other eligible ODS or high-GWP blowing agent container that has been identified and destined for destruction must

be weighed separately, sampled separately, and treated as a separate destruction event.

v. Recovery, collection, and aggregation activities may occur until the container has been identified and destined for destruction. After the ODS or high-GWP blowing agent container has been identified and destined for destruction, ODS or high-GWP blowing agent must not be added or removed, except for the purpose of sampling and analysis.

B. The following procedures must be applied for the full and empty masses required within 48 hours of both the commencement and conclusion of destruction, pursuant to subsections I A ii and I A iii in Appendix C of this Methodology:

i. For containers permanently affixed to a detachable trailer:

a. The trailer must be detached from its transportation vehicle, and the trailer must be weighed separately from its transportation vehicle;

b. Any accessories, such as spare tires or tire chains, or any part of the trailer's load other than the ODS or high-GWP blowing agent which are included in the trailer's full mass prior to ODS or high-GWP blowing agent destruction must be included in the trailer's empty mass after destruction; and

c. A container with a capacity over 1,000 pounds must be placed on the scale motionless for at least 3 minutes to allow the mass to stabilize before the mass measurement is recorded.

ii. For containers not permanently affixed to a truck or detachable trailer:

a. Each container may be weighed by placing it individually on the scale prescribed in subsection I A i in Appendix C of this Methodology; and;

b. A container with a capacity over 1,000 pounds must be placed on the scale motionless for at least 3 minutes to allow the mass to stabilize before the mass measurement is recorded.

iii. For containers weighed with the transportation vehicle included:

a. The driver and any other passengers must exit the vehicle such that their mass is not included;

b. Any accessories, such as spare tires or tire chains, or any part of the truck's load other than the ODS or high-GWP blowing agent which are included in the truck's full mass prior to ODS or high-GWP blowing agent destruction must be included in the truck's empty mass after destruction;

c. If more than 1,000 pounds of ODS or high-GWP blowing agent is being transported for destruction, then the truck must be situated motionless on the scale for at least 3 minutes to allow the mass to stabilize before the mass measurement is recorded.

d. The transportation vehicle's weight classification and load rating must be recorded;

e. The transportation vehicle's fuel capacity must be recorded. Its fuel level at the time of each scale recording must also be recorded. Fuel level must be recorded in an increment of one eighth of the fuel tank capacity. If the fuel level is in between two increments, the fuel level prior to ODS or high-GWP blowing agent destruction must be rounded down and the fuel level after ODS or high-GWP blowing agent destruction must be rounded up;

f. If the transportation vehicle's fuel level is lower after destruction than the fuel level before destruction, the difference in fuel mass must be subtracted, as applicable from $Q_{refr,i}$ in Equations 3 and 9, $EBA_{,i}$ and $BA_{intf,i}$ in Equation 5, Q_{aer} in Equations 6 and 11, $Q_{fs,i}$ in Equation 7 and Equation 12, and $Q_{ODS,}$ Q_{BA}, and Q_{intf} in Equation 13. The following fuel densities shall be used to adjust for mass:

7.0851 lb/gal for diesel; or

6.0023 lb/gal for gasoline; and

g. If different transportation vehicles are used to transport containers to a destruction facility and to pick up the empty containers after destruction, each transport vehicle shall be weighed both upon its arrival and departure from the destruction facility. If the vehicle transporting the full ODS containers to the destruction facility weighs more than the vehicle carrying the empty ODS containers from the facility, the mass discrepancy must be subtracted, as applicable from $Q_{refr,i}$ in Equations 3 and 9, $EBA_{,i}$ and $BA_{intf,i}$ in Equation 5, Q_{aer} in Equations 6 and 11, $Q_{fs,i}$ in Equations 7 and Equation 12, and $Q_{ODS,}$ Q_{BA}, and Q_{intf} in Equation 13.

C. Composition and concentration of ODS or high-GWP blowing agent must be established for each individual container by taking a sample from each container of ODS or high-GWP blowing agent and having it analyzed for composition and concentration at an AHRI-certified laboratory using the AHRI Standard 700 – Specifications for Refrigerants (AHRI 700). The laboratory performing the composition analysis must not be affiliated with the project proponent. All the following requirements must be met for each sample:

i. The sample must be taken while ODS or high-GWP blowing agent is in the possession of the company that will destroy the ODS or high-GWP blowing agent;

ii. Samples must be taken by a technician unaffiliated with the project proponent; if the destruction facility is the project proponent, an outside technician must perform this task;

iii. Samples must be taken with a clean, fully evacuated sample bottle that meets applicable DOT requirements with a minimum capacity of one pound;

iv. Each sample must be taken in liquid state;

v. A minimum sample size of one pound must be drawn for each sample;

vi. Each sample must be individually labeled and tracked according to the container from which it was taken, and all the following information recorded:

a. Time and date of sample;

b. Name of project proponent;

c. Name of technician taking sample;

d. Employer of technician taking sample;

e. Volume of container from which sample was extracted; and

f. Ambient air temperature at time of sampling; and

g. Chain of custody for each sample from the point of sampling to the AHRI-certified lab must be documented by paper bills of lading or electronic, third-party tracking that includes proof of delivery.

D. All project samples shall be analyzed using AHRI 700 to confirm the mass percentage and identification of each component of the sample. The analysis shall provide:

i. Identification of the ODS or high-GWP blowing agent;

ii. Purity (%) of the ODS or high-GWP blowing agent mixture by mass using gas chromatography;

iii. Moisture level in parts per million. The moisture content of each sample must be less than 75% of the saturation point for the ODS or high-GWP blowing agent based on the temperature recorded at the time the sample was taken;

a. For non-mixed ODS or high-GWP blowing agent, the saturation point is the saturation point of the major ODS or high-GWP blowing agent species;

b. For mixed ODS or high-GWP blowing agent, the saturation point is the lowest saturation value of any species that makes up at least 10% of the composition;

iv. Analysis of HBR, which must be less than 10% by mass; and

v. Analysis of other ODS or high-GWP blowing agent in the case of mixtures of ODS or high-GWP blowing agent, and their percentage by mass.

E. If any of the requirements in sections I A through I C of this appendix are not met, no GHG reductions may be verified for ODS or high-GWP blowing agent destruction associated with that container.

F. If a container holds non-mixed ODS or high-GWP blowing agent, no further information or sampling is required to determine the mass and composition of the ODS or high-GWP blowing agent. For non-mixed ODS or high-GWP blowing agent, the analysis conducted for the sample taken at the destruction facility must be used for quantifying GHG emissions.

G. If the container holds mixed ODS or high-GWP blowing agent, the project proponent must meet all the following additional requirements:

i. The required sampling may be conducted at the final destruction facility or prior to delivery to the destruction facility;

ii. Circulation and sampling activities must be conducted by a contracted third-party and by individuals who have been properly trained for the functions they perform;

iii. The offset project documentation must specify the procedures by which mixed ODS or high-GWP blowing agent are analyzed;

iv. Prior to sampling, the ODS or high-GWP blowing agent mixture must be circulated in a single container or two connected containers that meet all the following criteria:

a. The containers have no solid interior obstructions;

b. The containers were fully evacuated prior to filling;

c. The containers must have sampling ports to sample liquid and gas phase ODS or high-GWP blowing agent;

d. The sampling ports must be located in the middle third of all of the containers (i.e., not at one end or the other); and

e. The containers and associated equipment can circulate the mixture via a closed loop system from the bottom to top for a single container, or from the bottom of one tank to the top of another tank if two connected containers are used.

v. If the original mixed ODS or high-GWP blowing agent container or two connected containers do not meet these requirements, the mixed ODS or high-GWP blowing agent must be transferred into a temporary holding tank or container or two connected containers that meet all the above criteria. The mass of the contents placed into the temporary container or two connected containers shall be calculated and recorded. During transfer of ODS or high-GWP blowing agent into and out of the temporary container or two connected containers, ODS or high-GWP blowing agent shall be recovered to the vacuum levels required by the U.S. EPA for that ODS or high-GWP blowing agent (see 40 CFR 82.156);

vi. Once the mixed ODS or high-GWP blowing agent is in a container, two connected containers, or temporary storage unit that meets the criteria above, circulation of mixed ODS or high-GWP blowing agent must be conducted as follows:

a. Liquid mixture shall be circulated from the liquid port to the vapor port for a single container, or from the liquid port of one tank into the vapor port for another tank if two connected containers are used;

b. A volume of the mixture equal to two times the volume in the container shall be circulated;

c. Calculations converting between mass and volume shall use the densities provided in Table 8; if converting between mass and volume, the mixed ODS or high-GWP blowing agent must be in a liquid state;

d. Circulation must occur at a rate of at least 30 gallons/minute; and

e. Start and end times shall be recorded;

vii. Within 30 minutes of the completion of circulation, a minimum of two samples shall be taken from the bottom liquid port for a single container, or minimum of two samples must be taken from the liquid port of each tank if two connected tanks are used and both samples must be analyzed at an AHRI-certified laboratory; and

viii. The project proponent must calculate the project GHG emission reductions using both sample results, and choose the sample resulting in the lower project emission reductions.

II. Refrigerant and extracted high-GWP blowing agents destroyed in enclosed equipment demanufacturing systems shall be analyzed using FTIR. FTIR shall be used to determine the mass and composition of each ODS refrigerant and extracted high-GWP blowing agent destroyed.

APPENDIX D: DISCUSSION AND RATIONALE FOR UPDATES TO CARB ODS PROTOCOL

The California Air Resources Board (CARB) ODS Destruction Protocol was first adopted in 2011 and subsequently revised in 2014. The CARB ODS Protocol is essentially a re-formatting of the 2011 CARB ODS Protocol with no major substantive changes. In turn, the 2011 CARB ODS Protocol, with some minor exceptions, is based on a voluntary ODS protocol which was first developed in 2008-2009 and approved in 2010.

Consequently, all the underlying information relevant to additionality, quantification, and monitoring in the CARB ODS Protocol trace back to data and other information from 2008-2009 or earlier. In the nearly 7 years since, there have been several significant changes in underlying regulatory conditions, market dynamics, and baseline scenarios, and new technical data. These changes are summarized here for each of the major updates in this Methodology.

D.1 HIGH-GWP INSULATION FOAM

D.1.1 Eligibility of High-GWP Blowing Agents

The CARB ODS Protocol lists several ODS foam blowing agents that are eligible for destruction credits – CFC-11, CFC-12, HCFC-22, and HCFC-141b. These ODS were discontinued from use in foam applications beginning in 1996, and more recently in the case of HCFC-141b and HCFC-22, in 2003 and 2009, respectively. This Methodology adds two HFCs to the list of eligible blowing agents for foam destruction projects – HFC-134a and HFC-245fa.

These HFCs are in production in the U.S. for use in the manufacture of foam products, particularly appliance foam. Destruction of foam recovered from end-of-life appliances does not trigger additional production of the HFC blowing agents beyond what would be produced anyway.

At a macro-level, when an appliance reaches end-of-life, demand is created for the manufacture of a new replacement appliance. For example, the decision to purchase a new refrigerator-freezer, in general, is made when the old fridge is discarded. That decision at the consumer level translates to a decision at the manufacturing level to produce a new fridge. Today, the new fridge may be manufactured with insulation foam containing HFC-134a, HFC-245fa, or in some

cases, a hydrocarbon-based blowing agent. Regardless of how the foam in the end-of-life appliance is discarded - shredded and landfilled (the baseline scenario), or incinerated in conformance with this Methodology - the same quantity of new blowing agent will be produced for use in a newly manufactured appliance. As is the case for ODS refrigerants and the other eligible ODS categories in this Methodology, destruction of CFC, HCFC, and HFC blowing agents therefore prevents greenhouse gas emissions that would otherwise occur under the baseline scenario (shredding and landfilling of the foam).

D.1.2 Eligibility of High-GWP Foam Sources

In addition to the inclusion of new high-GWP foam blowing agents, this Methodology has been expanded to include additional foam sources. The CARB ODS Protocol only allows foam removed from appliances or buildings. Based on industry communications and research conducted during the development of this Methodology, it was determined that there were no compelling reasons to exclude additional sources of high-GWP foam. Therefore, the following sources have been added:

- Walk-in coolers,
- Refrigerated transportation,
- Refrigeration cases,
- Pipe-in-pipe/preformed pipe, and
- Marine applications.

D.1.3 Foam Baseline Emission Rates

For quantification of baseline emissions of ODS from appliance foam, the CARB ODS Protocol used estimates of how ODS blowing agents are released during: (a) foam shredding, (b) foam compaction, and (c) landfill decomposition. Foam shredding and foam compaction release rates of ODS blowing agents were estimated to be 24% and 19%, respectively, derived from research at the Institute of Environment and Resources at the Technical University of Denmark (Kjelsdsen et al., 2000, 2003).

The estimated release of ODS from shredded foam material in the landfill used in the CARB ODS Protocol was derived from a laboratory study (Scheutz et al., 2007) where pure ODS blowing agent was mixed in test tubes with simulated landfill material, and inoculated with anaerobic bacteria capable of digesting CFCs and HCFCs. As noted by the investigators, the study was not intended to reflect real world conditions, for example:

- The idealized anaerobic conditions maintained in the laboratory test tubes would be unlikely in an active landfill;

- The "landfill" material in the study contained only shredder residue, rather than the diverse mix of solid waste in a typical municipal landfill; and,
- In contrast to the simulated conditions in the experiments, actual landfills would not be biologically pretreated, and there would be larger quantities of landfill gas generated.

Scheutz et al. (2007) modeled two diffusion rate coefficients to analyze the sensitivity of this factor in predicting the fraction of blowing agent that would be released in landfilled foam (see Table 9).

Table 9: Summary of results from Table 3 of Scheutz et al. (2007)

PERCENTAGE OF BLOWING AGENT RELEASED FROM LANDFILLED FOAM	CFC-11	HCFC-141B	CFC-12	HCFC-22
Lower Bound (%)	35	41	52	100
Upper Bound (%)	83	91	98	100
Mid-Point (%)	59	66	75	100

The voluntary protocol upon which the CARB ODS Protocol is based used only the lower bound result from the Scheutz et al. (2007) modeling (35% of the CFC-11 blowing agent remaining in the landfilled material would be released in the landfill), and conservatively assumed that 95% of that CFC-11 would undergo anaerobic degradation in landfills. This resulted in an estimate that 1% (0.35 * (1-.95)) of the CFC-11 blowing agent in landfilled appliance foam would be released to the atmosphere.

A German research institute (RUK Ingenieugruppe, 2012) subjected the assumptions made in Scheutz et al. (2007) to experimental and computational checks and concluded the following:

- Scheutz et al. (2007) assumed that the half-life of the anaerobic degradation of CFC-11 was **ten times** longer than that indicated by the laboratory experiments;
- A value of 5% for the percentage of CFC-11 that would not undergo anaerobic degradation is only justified for the kind of "mono-landfill" investigated by Scheutz et al. (2007) that generates very small quantities of landfill gas. Only in very rare cases will the type of mono-landfill assumed in the CARB ODS Protocol provide an adequate representation of baseline emissions; and
- The value assumed for the percent of ODS blowing agent degraded should reflect the particular type of landfill under consideration.

RUK Ingenieugruppe calculated CFC-11 landfill degradation rates for a range of solid-waste disposal sites representing a range of climate zones. The re-calculated degradation rates are based on case studies using the landfill gas forecasting model used in CDM and JI projects, approved by the UNFCCC (see Table 10).

Table 10: Recalculated degradation rates for solid waste disposal in various climate zones

LOCATION	CLIMATE ZONE	PERCENT OF RELEASED CFC-11 BLOWING AGENT NOT DEGRADED IN ANAEROBIC LANDFILL CONDITIONS
Europe: Central, without biological pre-treatment[8]	Wet temperate	83.6%
Europe: Northern	Wet temperate	64.2%
Asia: South-central	Moist and wet tropical	62.9%
Africa: Southern	Wet temperate	61.9%
America: Central	Dry tropical	55.2%
Asia: Western & Middle East	Dry temperate	48.3%
Minimum: mono-landfill for shredder waste	(no relevant influence)	5.0%

More recently, CARB and the California EPA commissioned a study by the Global Waste Research Institute at California Polytechnic State University, the University of California-Irvine, and the University of Illinois at Chicago to assess fluorochemical (CFCs, HCFCs, HFCs) emissions from discarded appliance and building foam insulation in landfills (Yesiller et al., 2016). The study consisted of: 1) a comprehensive literature review of emissions data for fluorocarbon blowing agents from landfills; 2) a materials flow analysis to quantify emissions between appli-

[8] All locations in Europe, with the exception of Northern Europe, were calculated for landfills without biological treatment.

ance and building material end of life and time of entry to landfills; and 3) an extensive field testing program at a landfill in Northern California to measure air quality and gas emissions under different cover types and over different seasons.

D.1.3.1 BASELINE BLOWING AGENT EMISSION RATES FOR FOAM WASTE PRIOR TO LANDFILLING

Table 11 provides the estimated rates by which different blowing agents are released during different stages of appliance foam waste disposal up to the time the foam waste is landfilled. The values are from the materials flow analysis conducted by Yesiller et al. (2016) which quantified blowing agent emissions between appliance end-of-life and the time of entry of the foam waste to the landfill. The values are the proportions of remaining blowing agents released at different stages of foam disposal relative to the initial amount of blowing agents present in new foam materials at the beginning of service life.

For this Methodology, the baseline scenario for appliance foam disposal is shredding of the appliance, with no manual foam recovery, followed by landfilling of the foam material.

The investigators did not include HCFC-22 blowing agent in their analysis; for this Methodology, the emission rates calculated in Yesiller et al. (2016) for HCFC-141b are assumed for HCFC-22.

Table 11: Calculated Blowing Agent Release Fractions from Domestic Appliance Foam Waste

DISPOSAL STAGE	FRACTION OF THE INITIAL BLOWING AGENT CONTENT RELEASED (%)			
	CFC-11	**HCFC-141b**	**HFC-134a**	**HFC-245fa**
Foam Recovery	4	4	4	4
Transportation	2	1.3	2.3	2.6
Shredding	24	24	24	24
Stockpiling at Landfill for Alternative Daily Cover	2.2	2.3	2.2	2.2
Total Excluding Foam Recovery	**28.2**	**27.6**	**28.5**	**28.8**

Tables 12 through 15 present the pre-landfill blowing agent emission rates for the other foam waste categories that were quantified in the Yesiller et al. (2016) materials flow analysis.

Table 12: Calculated Blowing Agent Release Fractions from Building Foam Waste[9]

DISPOSAL STAGE	FRACTION OF THE INITIAL BLOWING AGENT CONTENT RELEASED (%)			
	CFC-11	**HCFC-141b**	**HFC-134a**	**HFC-245fa**
Decommissioning	3	3	3	3
Transportation	2.6	2	2.3	2.4
Shredding	24	24	24	24
Stockpiling at Landfill for Alternative Daily Cover	2.5	2.1	2.9	2.75
Total without Decommissioning[10]	**29.1**	**28.1**	**29.2**	**29.2**

[9] Yesiller et al. (2016) analyzed blowing agent emissions from end-of-life building insulation in construction and demolition foam waste.

[10] Blowing agent emissions from building decommissioning are not included in the baseline because the same emissions would occur in the project scenario.

Table 13: Calculated Blowing Agent Release Fractions from Commercial Appliance/Water Heater Foam Waste[11]

DISPOSAL STAGE	FRACTION OF THE INITIAL BLOWING AGENT CONTENT RELEASED (%)			
	CFC-11	**HCFC-141b**	**HFC-134a**	**HFC-245fa**
Transportation	1.63	1.2	1.9	2
Shredding	24	24	24	24
Stockpiling at Landfill for Alternative Daily Cover	4.4	4.4	4.5	5
Total	**30**	**29.6**	**30.4**	**31**

Table 14: Calculated Blowing Agent Release Fractions from Refrigerated Transport Foam Waste[12]

DISPOSAL STAGE	FRACTION OF THE INITIAL BLOWING AGENT CONTENT RELEASED (%)			
	CFC-11	**HCFC-141b**	**HFC-134a**	**HFC-245fa**
Transportation	1	1	1	1
Shredding	24	24	24	24
Stockpiling at Landfill for Alternative Daily Cover	4.4	4.4	4.5	5
Total	**29.4**	**29.4**	**29.5**	**30**

[11] Commercial appliances include grocery display cases, stand-alone refrigeration equipment, and vending machines.

[12] Refrigerated transport includes the transport refrigerated units used for transportation of perishable goods in trucks, vans, rail units, and ships.

Table 15: Calculated Blowing Agent Release Fractions from Marine and Other Waste Foams[13]

DISPOSAL STAGE	FRACTION OF THE INITIAL BLOWING AGENT CONTENT RELEASED (%)			
	CFC-11	**HCFC-141b**	**HFC-134a**	**HFC-245fa**
Transportation	1.2	1.1	1	1.1
Shredding	24	24	24	24
Stockpiling at Landfill for Alternative Daily Cover	4.4	4.4	4.6	5
Total	**29.6**	**29.5**	**29.6**	**30.1**

D.1.3.2 BASELINE BLOWING AGENT EMISSION RATES FROM FOAM WASTE IN THE LANDFILL

Based upon analysis of published landfill modeling studies, including the Scheutz et al. studies relied upon in the original ODS destruction protocol adopted by CARB, as well as relevant additional studies (Scheutz and Kjeldsen, 2003; Fredenslund et al., 2005; ICF, 2011), Yesiller et al. (2016) estimated release rates of fluorochemical blowing agents in the landfill environment over three time periods, summarized in Table 16. The shredded insulation foam waste category includes both domestic and commercial insulation foam waste. The “Panel Insulation Foam” category includes building foam and other types of foam (e.g., refrigerated transport, marine, walk-in coolers).

The time periods for blowing agent releases in the landfill were defined by Yesiller et al. (2016) to include the following processes:

- Initial releases from compaction of shredded foam or discarded foam panels
- Short-term releases over hours to days occurring during the aerobic period as well as during the adjustment period from aerobic to complete anaerobic degradation
- Long-term releases over weeks to years from microbial degradation

[13] Marine and other foam insulation includes foam used in boats and walk-in cold storage applications.

Table 16: Baseline Emission Rates for Blowing Agents in the Landfill Environment[14]

WASTE TYPE	INITIAL RELEASE	SHORT-TERM RELEASE	LONG-TERM RELEASE WITH LANDFILL GAS RECOVERY
Shredded Insulation Foam Waste	10%	14%	18%
Panel Insulation Foam Waste	11%	19%	29%

D.1.3.3 AGGREGATED BASELINE BLOWING AGENT EMISSION RATES

Table 17 combines the pre-landfill emission rates of blowing agents from foam wastes encompassing foam waste transportation, foam shredding, and foam stockpiling (Tables 11 through 15) as well as blowing agent releases from foam waste in the landfill (Table 16). For purposes of this Methodology, the foam categories used by Yesiller et al. (2016) are divided into three categories: appliance foam, building foam, and "other foam".

The appliance foam category includes both domestic and commercial appliances and water heaters. Under the baseline scenario, it is assumed that foam recovered from these units are shredded prior to landfilling. The "pre-landfill" blowing agent emission rates for domestic appliance foam waste calculated by Yesiller et al. (2016) are lower than those for commercial appliances and water heaters; therefore, the blowing agent emission rates for domestic appliance foam waste are used to represent the appliance foam category.

The "other foam" category includes insulation used for commercial appliances, water heaters, refrigerated transport, boats, walk-in coolers, and other miscellaneous applications. Yesiller et al. (2016) calculated nearly identical emission rates for the various foam waste types in the "other" category; for purposes of this Methodology, the rates calculated for refrigerated transport foam are assigned to the "other foam" category because they are the lowest rates reported in the study.

Pre-landfill emission rates for CFC-12 and HCFC-22 blowing agent were not calculated in the materials flow analysis by Yesiller et al. (2016) although both were included in the literature review analysis of landfill emission rates and in the field measurements at the California landfill.

[14] From Table 1.10 in Yesiller et al. (2016); values presented are the mean estimates for the various categories.

For purposes of this Methodology, rates calculated for CFC-11 blowing agent are assigned to CFC-12 blowing agent, and emission rates for HCFC-141b are assigned to HCFC-22.

Table 17: Emission Rates for Blowing Agents in Appliance, Building, and Other Foam in Baseline Scenario

HIGH-GWP BLOWING AGENT	APPLIANCE HIGH-GWP BLOWING AGENT 10-YEAR EMISSION RATE ($ER_{I,J}$)	BUILDING HIGH-GWP BLOWING AGENT 10-YEAR EMISSION RATE ($ER_{I,J}$)	"OTHER FOAM" HIGH-GWP BLOWING AGENT 10-YEAR EMISSION RATE ($ER_{I,J}$)
CFC-11	70.2%	88.1%	88.4%
CFC-12	n/a	88.1%	88.4%
HCFC-22	69.6%	87.1%	88.4%
HCFC-141b	69.6%	87.1%	88.4%
HFC-134a	70.5%	88.2%	88.6%
HFC-245fa	70.8%	88.2%	89.1%

D.1.4 High-GWP Foam Emissions Reduction Quantification

In addition to the changes regarding emission rates discussed above, this Methodology significantly simplifies the process of emission reduction quantification for high-GWP foam projects that extract blowing agents. The CARB ODS Protocol requires the calculation of a recovery efficiency which has been removed as it was unnecessary to accurately determine baseline emissions for blowing agents that are extracted and concentrated. The concept of recovery efficiency was also applied in the determination of foam project emissions.

D.1.5 High-GWP Foam Blowing Agent Concentration and Analysis

This Methodology preserves the ability of a project proponent to extract high-GWP blowing agents, containerize them, and have the constituents analyzed just as any refrigerant, medical aerosol, or fire suppressant ODS destruction project. However, it is highly unlikely, due to cost

and complexity, that this method will be employed in practice. To that end, the Methodology includes provisions for the destruction of extracted blowing agents in enclosed equipment de-manufacturing systems. Recently, new equipment de-manufacturing technologies have been introduced that allow for a closed loop process where blowing agents are extracted and destroyed in enclosed systems. These systems are capable of real time analysis of constituent gases as well as the determination of total volumes destroyed over selected time frames. The Methodology includes requirements for the necessary continuous monitoring and maintenance of these systems.

D.1.6 Project Emissions During Removal of Foam from Appliances

For appliance foam ODS destruction projects that do not involve foam extraction within an enclosed appliance de-manufacturing system, project emissions include the ODS foam blowing agent that is released during manual removal of the foam from the interior walls of the appliance. The 2005 TEAP Task Force on Foam End-of-Life Issues (TEAP 2005) cited research (JTCCM, 2004) that showed that emissions of ODS blowing agent from manual removal of foam can range from 1.5 to 5%.

A more recent life-cycle analysis on appliances used an assumption based on industry input that emissions of blowing agent from manual foam removal can range from 10-15% but could be lower if best practices are used (ICF, 2011). The industry input was provided by two U.S. appliance recyclers. One of the recyclers had employed manual foam removal in unconfined space. That company is no longer operating and has since been replaced in the market by a business that relies exclusively on enclosed equipment de-manufacturing in which the insulation foam is separated in a closed system under negative pressure, resulting in no fugitive emissions.

The Yesiller et al. (2016) analyses calculated blowing agent emissions from appliance foam recovery rate in the range of 4% of the initial blowing agent content (see Table 11).

Given the full range of estimates (1.5% to 15%), and the more recent trends in the U.S. towards more advanced appliance recycling technology, this Methodology applies a default value of 10% for the ODS blowing agent project emissions from removal of foam from appliances in a non-enclosed equipment de-manufacturing system, as specified in Equation 10.

D.2 HCFC-22 REFRIGERANT

HCFC-22 was excluded as an eligible refrigerant at the time of development of early ODS destruction protocols because HCFC-22 production in the U.S. was not controlled.[15] Beginning in 2010, the phase out of HCFC-22 began in the U.S. under the U.S. Clean Air Act. As of January 1, 2010, production and import of HCFC-22 was banned except for servicing equipment manufactured before January 1, 2010.

Newer equipment manufactured after January 1, 2010 must be serviced with reclaimed HCFC-22 refrigerant. To service older equipment, the U.S. EPA has issued annual production and import consumption[16] allowances, with a declining cap, to 21 companies, including chemical producers and equipment manufacturers. EPA has developed its annual allocations based on precise calculations of the servicing needs of the industry (EPA, 2014 – see Table 18). These allocations will continue through 2019. On January 1, 2020, all production and import of HCFC-22 will end in the U.S.

Table 18: EPA's Annual HCFC-22 Consumption Allowances Relative to Baseline

YEAR	% OF BASELINE
2009	100
2010	41.9
2011	32.0
2012	17.7
2013	18.0
2014	14.2
2015	7.0
2016	5.6
2017	4.2

[15] Destruction credits for HCFC-22 foam blowing agent was allowed because its use in the U.S. as a blowing agent ended as of March 1, 2008.

[16] Consumption = (Production + Imports) - Exports

YEAR	% OF BASELINE
2018	2.8
2019	1.4
2020	0

D.2.1 Additionality of HCFC-22 Destruction

First, as is the case for CFCs, there is no requirement for destruction of HCFC-22 in the U.S.

Second, as also is the case for CFC refrigerants, under business as usual, all HCFC-22 currently in equipment will either leak, or be recovered for re-use in other leaky equipment. Thus, all HCFC-22 that has been produced will ultimately be released to the atmosphere.

The question is whether destruction of HCFC-22 would trigger *new* production and therefore has no net benefit.

This Methodology enables offset credits from destruction of HCFC-22 only under the condition that the HCFC-22 is recovered from refrigeration or air conditioning equipment and that equipment is subsequently de-commissioned as part of the project. Destruction of HCFC-22 stockpiles is not eligible for offset credits. Because of the hard caps established by EPA, destruction of HCFC-22 recovered from retired equipment cannot trigger any additional production or importation:

- Manufacture of new equipment containing HCFC-22 is prohibited; the retired equipment would be replaced with new equipment containing alternative refrigerants such as HFCs, HFOs, hydrocarbons, ammonia, or CO_2;
- Removal of HCFC-22 from the “national inventory” via destruction could not be replaced by new production or import, but it would increase incentives for recovery and recycling/reclamation of remaining sources of HCFC-22.

There is no expected adverse impact in terms of affecting the market availability of HCFC-22 needed for servicing older equipment. Any destruction would be done on a voluntary basis to accelerate the retirement of older equipment. Companies with annual consumption allowances can be expected to maximize the quantities of HCFC-22 that they produce and/or import to build up inventories for future needs, regardless of how much HCFC-22 is destroyed.

D.2.2 HCFC-22 Emission Rate

Table 19 summarizes the calculation of the 10-year emission rate for HCFC-22 from refrigeration and air conditioning equipment. Recent data and modeling assumptions from the EPA and the CARB (CARB, 2009) are incorporated.

Table 19: 2015 Weighted Average Annual Loss Rate Percent and Market Share for HCFC-22

REFRIGERATION AND A/C SECTOR	HCFC-22 MARKET SHARE[17]	HCFC-22 ANNUAL LOSS RATE[18]
Mobile	-	-
Large Refrigeration	17%	27%
Large A/C	83%	5%
Market-Weighted Annual Loss Rate	12.1%	
10-year Total Loss	72%	

D.2.3 HCFC-22 Substitute Emissions

The GHG emissions of substitute refrigerants associated with project scenario emissions are estimated using Equation 9. The approach is based on the fact that by removing ODS ref5rigerant through destruction projects – including HCFC-22 - from the re-sale market, substitute refrigerants will be required to fulfill demand in the U.S. for refrigeration and air conditioning. The impacts of these substitute refrigerants are calculated for different end-use categories based on leak rates, relative charge sizes, and the proportion of HCFC-22 used, as modeled by the EPA Vintaging Model (U.S. EPA 2015a). Market share allocations account for recently published EPA SNAP regulations that make several HFC refrigerants unacceptable for use for commercial refrigeration and air conditioning applications, with effective dates ranging from 2016 to 2020

[17] Calculated from U.S. EPA data on average charge sizes for commercial A/C, chillers, retail food refrigeration, cold storage, and industrial process refrigeration systems and U.S. Department of Energy data on commercial buildings in the U.S.

[18] From U.S. EPA Vintaging Model and CARB data on refrigeration and air conditioning leak rates in California facilities.

(80 FR 42870, July 20, 2015; EPA, 2015b). Table 20 provides the calculations of emissions of substitute refrigerants associated with destruction of HCFC-22.

Table 20: Calculation of Substitute Emissions for HCFC-22

APPLI-CATION	HCFC-22 MAR	HCFC-22 SUBSTI-TUTE	MARKET SHARE RELATIVE TO SUB-SECTOR (BY MASS)	OVER-ALL HCFC-22 MAR-KET SHARE	GWP	RELA-TIVE CHARGE SIZE (LB SUB/ LB ODS)	SUB USED TO REPLACE ONE LB HCFC-22 (LBS)	LOSS RATE OF SUB (%/YR)	10-YR LBS **CO_2E/** ODS DE-STROYED
Large Refriger-ation	0.32	R-407C	50%	16%	1774	0.78	0.125	2%	40.59
		HFC-134a	5%	1.6%	1430	1.4	0.02	18%	27.69
		CO2	22.5%	7.2%	1	1	0.07	2%	0.01
		Hydro-carbons	22.5%	7.2%	1	1	0.07	2%	0.01
Large A/C	0.68	HFC-134a	85%	57.74%	1430	1.4	0.808	3%	303.50
		R-407C	10%	6.79%	1774	0.76	0.052	2%	16.75
		HFOs	5%	3.40%	1	0.76	0.026	1%	0.0025
	HCFC-22-Sub Emissions (lbCO2e/lbHCFC-22 destroyed)								**388.57**

D.3 MEDICAL AEROSOL ODS

D.3.1 CFC Phaseout

Under the Montreal Protocol “essential use nominations” program, limited production of CFCs was authorized in the U.S. and other countries for use as the propellant in metered dose inhalers (MDIs), which are relied upon by asthmatics, and in other medical devices. Essential use production for MDIs in the U.S. was gradually phased out as the Food and Drug Administration approved CFC-free products for treatment of asthma, chronic obstructive pulmonary disease, and other respiratory diseases, including HFC-propelled MDIs, dry powder inhalers, and oral medications. As of January 1, 2012, all production and import of CFCs in the U.S. for MDIs ended, and on January 1, 2013, sale of CFC-based inhalers ended in the United States.

Two medical products remain classified as essential uses of CFC propellant: anesthetic drugs requiring a cannula for application for use on accessible mucous membranes (21 CFR 2.125(e)(4)(iii)), and sterile aerosol talc administered intrapleurally by thorascopy (21 CFR 2.125(e)(4)(ix)).

D.3.2 Additionality of Destruction of U.S. Inventories

Some of the CFCs that had been produced under the essential use nominations in the U.S. before 2012 have never been used. The resulting stockpile is eligible for sale in the United States for use in remaining essential use applications. Given continued demand for CFC-11 and CFC-114 for at least one of the exempted products, under business as usual, the U.S. CFC stockpile would be sold for use as a propellant in the exempted product, and eventually released to the atmosphere. In contrast, under the alternative "project" scenario, the CFCs would be destroyed, preventing direct GHG emissions, and result in increased use of CFC-free alternative products.

Any additional production of CFCs in the U.S. for remaining essential uses would require approval by the Parties to the Montreal Protocol, as recommended by the Montreal Protocol Medical Technical Options Committee of the Technology and Economics Assessment Panel. Production of CFCs for asthma inhalers has ended. Because of the remaining stockpiles, there is no indication and virtually no likelihood that the U.S. would request any new production of CFCs for the remaining exempted products. In other words, if some of the existing CFC stockpiles are destroyed, there would be no new, compensatory CFC production.

D.3.3 Emission Rates

The CFC and HFC propellants in medical products provide the chemical energy to uniformly deliver medication onto target tissues. With each discharge of the product, the propellant is emitted and eventually reaches the atmosphere. The EPA Vintaging Model assumes that for aerosol propellants, all emissions occur when the product is used. For purposes of this Methodology, it is assumed that 100% of the CFC (baseline scenario) and HFC (project scenario) propellants used as medical aerosols are emitted to the atmosphere within the 10-year crediting period.

D.3.4 CFC Substitute Emissions

In response to the Montreal Protocol phase out of CFCs, the pharmaceutical industry, with oversight from the U.S. Food and Drug Administration, developed CFC-free formulations to serve asthmatics and other patients with chronic respiratory disease. Following extensive safety studies and engineering innovations, two HFC propellants were approved – HFC-134a and HFC-

227ea – for use in MDIs in the United States. The ban on CFCs has also spurred new dry powder technology and other classes of specialty inhalers but these are not relevant alternatives for the remaining exempted products.

If remaining stockpiles of medical aerosol CFCs are destroyed in the U.S., there would be commensurate additional production and use of alternative propellants to meet overall patient needs.

For purposes of this Methodology, it is assumed that additional production of propellants, and atmospheric emissions, will be divided amongst HFC-134a and HFC-227ea according to their current market share in the United States for use in MDIs. Table 21 provides the calculations of emissions of the CFC substitutes associated with destruction of CFC medical aerosols. U.S. market shares for CFC-substitute propellants used in MDIs along with their GWPs are derived from Tope (2015).

Table 21: Medical Aerosol Substitute Emissions

APPLICATION	CFC MARKET SHARE	CFC SUBSTITUTE	MARKET SHARE RELATIVE TO SUB-SECTOR (BY WEIGHT)	OVERALL CFC MARKET SHARE	GWP	RELATIVE CHARGE SIZE (LB SUB/ LB ODS)	SUB USED TO REPLACE ONE LB CFC (LBS)	LOSS RATE OF SUB (%/YR)	10-YR LBS **CO_2E/** ODS DESTROYED
Self-Pressurized Medical Products	10%	HFC-134a	95%	9.50%	1430	1	0.095	100%	135.85
		HFC-227ea	5%	0.50%	3320	1	0.005	100%	16.60
	ODS Sub Emissions (lb CO2e/lb ODS destroyed)								**152.45**

D.4 ODS FIRE SUPPRESSANTS

D.4.1 Atmospheric Impacts and Applications of Halons and Substitutes

Similar to CFCs and HCFCs, halon fire suppressants are controlled under the Montreal Protocol. Halons contain bromine, which destroys stratospheric ozone at a rate many times higher than chlorine. Because of their high ozone depleting potentials, halons were phased out of production in the U.S. as of January 1, 1994, prior to CFCs. As of January 1, 2010, halon production in developing countries ended.

Halon 1211 is contained in older portable "streaming" fire extinguishers, and halon 1301 is contained in older "total flooding" systems ranging in size from large computer rooms, bank vaults, libraries, oil and gas extraction facilities and submarines, to the engine nacelle on jets (HTOC, 2014). There are several alternative non-ODS fire suppression agents now in wide use, many with significantly lower GWPs (e.g., water mist, CO2, nitrogen, fluoroketone) compared to halons, while others have comparable GWPs (HFC-227ea, HFC-236fa).

As of a decade ago, 75% of original halon use had been switched to agents with little or no climate impact; 4% of the original halon applications continued to employ halons. Most of the remaining 21% had been switched to HFCs and to a limited extent, PFCs (IPCC/TEAP, 2006). Table 22 lists the GWPs of ODS fire suppression agents and their substitutes.

Table 22: ODS Fire Suppression Agents and Substitutes[19]

ODS AGENT	GWP	NON-ODS ALTERNATIVE	GWP
Halon 1211	1860	HFC-23	14,310
Halon 1301	7030	HFC-227ea	3,350
HCFC Blend B	650	HFC-125	3,170
		HFC-236fa	9,500
		Dry chemical	1[20]
		CO_2	1
		FK-5-1-12	<1
		Inert Gas	0
		Water mist	0

[19] EPA SNAP Substitutes for Total Flooding Agents and Streaming Agents www.epa.gov/snap/fire-suppression-and-explosion-protection

[20] Dry chemical in some cases releases CO_2

D.4.2 Conditions for Halon Destruction Credits and Additionality

This Methodology enables offset credits for destruction of halons recovered from fire suppression equipment under the condition that the equipment is subsequently de-commissioned as part of the project. Similar to HCFC-22 refrigerant, destruction of halons recovered from end-of-life equipment will have the following impacts:

- Prevention of the inevitable emissions of halons from the older equipment via leaks, testing, accidental discharges, or release during fire extinguishing; and
- Incentivization of the continued transition to safe and effective halon alternatives, including many with little or no climate impact.

Destruction of halons under the conditions specified in the Methodology meets the additionality criteria because:

- As is the case for refrigerants, halons recovered from end-of-life equipment can be expected to be re-used to recharge other older equipment and systems. While fire suppression equipment is typically well maintained and monitored, releases occur during testing, transfers, and accidental discharges. The intended use of these agents is for release in the event of a fire or explosion. Ultimately, these agents are emitted.
- There is no requirement in the U.S. that halons recovered from equipment be destroyed; and
- Destruction of the halons will not trigger any additional halon production because of the complete phaseout of halons worldwide.

D.4.3 Halon Stockpiles

This Methodology does not allow credits for destruction of halon 1301 stockpiles because any remaining halon 1301 stockpiles likely include strategic reserves that are being maintained for fire suppression systems in aviation, shipping, oil and gas, computer rooms, and other critical applications.[21] Even though all projects under this Methodology would be voluntary activities, there is concern that the potential availability of carbon offset credits would incentivize premature destruction of important halon 1301 stockpiles.

[21] As of a decade ago, stockpiles of halon 1211 for portable fire extinguishers were maintained in lesser quantities (HTOC, 2006).

D.4.4 Emission Rates

In contrast to refrigerants that slowly leak from air conditioning and refrigeration equipment, halons are used in equipment and systems that are designed to discharge completely when deployed. Halon-based fire suppression systems and equipment that are properly maintained retain their charges with relatively low leak rates in order to deliver critical fire protection. However, in addition to system deployment for actual fires or explosions, significant releases do occur during routine testing, accidental discharges, and in some operations, for example, fighter jet fuel tank inerting during combat conditions (Klein, 1981).

One approach would be to assume a 100% emission rate to account for the fact that halons in fire suppression systems will eventually be released under business as usual. This would be a departure from the standard approach used for ODS refrigerants elsewhere in this Methodology and would be a departure from other ACR methodologies that only calculate GHG emission reductions over a 10-year crediting period. For halon projects, this Methodology will continue to calculate emission reductions within the 10-year crediting period, and use annual emission rates as a starting point.

When averaged over all applications, halon emission rates have been estimated to range between 1.5% to 5% per year for halon 1301, and 2% to 11% per year for halon 1211 (IPCC/TEAP, 2006). The 2006 IPCC Guidelines for National Greenhouse Gas Inventories cites a study that indicates average annual emissions from installed flooding systems are in the range of 1 to 3% (Verdonik and Robin, 2004), and cites a range of emissions rates between 2 and 6% per year for halon 1211 portable extinguishers (HTOC, 2003).

The estimated rates for halon 1211 emissions from portable fire extinguishers cited above remain useful because under a baseline scenario, any recovered halon 1211 would be used for similar streaming applications to recharge halon 1211-based portable fire extinguishers. In the case of halon 1301, however, using estimated emission rates averaged across all types of “total flooding” systems is not the most accurate approach. Under a baseline scenario, any halon 1301 recovered from de-commissioned systems would most likely be used to service “legacy” systems in civil aviation which are considered to be the most dependent on continued availability of halon 1301 stockpiles and the most demanding (HTOC, 2014). This dependency is magnified because even today, newly manufactured commercial aircraft in the U.S., with 25-30 year lifespans, use halon 1301 for engine compartments and auxiliary power units, and cargo bays (HTOC, 2014). (Beginning in the early 1990s, military aircraft have successfully transitioned to non-halon alternatives for engine fire protection and cargo bays and all other fire protection applications.)

Recent Montreal Protocol TEAP assessments estimate that halon 1301 emissions from civil aviation applications in the year 2020 will range between 6.1% to 8.1% per year (HTOC, 2006). Given the continuing reliance on halon 1301 in civil aviation to maintain systems in the oldest

aircraft remaining in service, this Methodology uses the upper end of this range (8.1% per year) for the default annual emission rate for halon.

D.4.5 Halon Substitute Emissions

Halon substitute emissions for the halon destruction project scenarios are calculated in Tables 23 and 24. Substitute emissions for halon 1211 and halon 1301 are based on the average market share of substitutes, their emission rates and relative charge sizes as specified in the EPA Vintaging Model (US EPA, 2015a)). Market share of PFC-based fire suppressants are adjusted downward to account for proposed restrictions under the U.S. EPA SNAP program. It is possible that the SNAP program will also restrict the use of high-GWP HFC fire suppressants, similar to actions taken in other sectors (EPA SNAP Rule 21, September 26, 2016). This Methodology will be revised to conform to future SNAP regulations that are relevant to the quantification of substitute emissions. Similarly, market share of HCFC-based fire suppressants will be adjusted to account for the ongoing HCFC phase-out in the United States.

Table 23: Calculation of Substitute Emissions for Halon 1211

APPLICATION	HALON 1211 MARKET SHARE	HALON 1211 SUBSTITUTE	MARKET SHARE RELATIVE TO SUB-SECTOR (BY WEIGHT)	OVERALL HALON 1211 MARKET SHARE	GWP	RELATIVE CHARGE SIZE (LB SUB/ LB ODS)	SUB USED TO REPLACE ONE LB HALON 1211 (LBS)	LOSS RATE OF SUB (%/YR)	10-YR LBS **CO_2E/** HALON DESTROYED
Streaming Fire Suppression	5%	HFC-236fa	2%	0.1%	9810	0.5	0.000	6.0%	2.18
		HCFC Blend B (Halotron)	5%	0.25%	650	1	0.003	6.0%	0.75
		Non-ODP/GWP	93%	4.65%	0	1	0.047	6.0%	0.00
	Halon 1211-Sub Emissions (lb CO_2e/lb Halon 1211 destroyed)								**2.93**

Table 24: Calculation of Substitute Emissions for Halon 1301

APPLI-CATION	HALON 1301 MAR-KET SHARE	HALON 1301 SUBSTI-TUTE	MARKET SHARE RELATIVE TO SUB-SECTOR (BY WEIGHT)	OVER-ALL HALON 1301 MAR-KET SHARE	GWP	RELA-TIVE CHARGE SIZE (LB SUB/ LB ODS)	SUB USED TO REPLACE ONE LB HALON 1211 (LBS)	LOSS RATE OF SUB (%/YR)	10-YR LBS **CO_2E/** HALON DE-STROYED
Total Flood-ing Fire Sup-pres-sion	4%	HFC-227ea	47%	1.88%	3220	0.6	0.275	3.0%	232.56
		FK-5-1-12	40%	1.60%	1	1.0	0.400	3.0%	0.11
		HFC-125	3%	0.12%	3500	0.8	0.024	3.0%	21.62
		Non-ODP/GWP	10%	0.40%	0	1.0	0.100	3.0%	0.00
	Halon 1301 Sub Emissions (lb CO_2e/lb Halon 1301 destroyed)								**254.28**

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ACKNOWLEDGEMENTS

This methodology was developed by Dentons U.S., LLP, in cooperation with Foam Supplies, Inc., Global Chemical Consultants, and Susan Wood Consulting. True Manufacturing, Inc. co-operated with version 2.0 of this methodology.

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ACRONYMS AND DEFINITIONS

If not explicitly defined here, the current definitions in the most recent version of the American Carbon Registry (ACR) Standard apply.

TERM	ACRONYM (if applicable)	DEFINITION
Baseline blowing agent	Baseline BA	The BA that is being transitioned to an Eligible BA through the Project Activity.
Blowing agent	BA	The material used to propel foam mixture for its required use. BAs can also be used as an insulating component of foam. BAs are the main component that make up the GHG emissions associated with foam manufacturing, use and EOL.
Blowing agent blends	BA blends	The use of two or more BAs in the baseline or project.
Blowing agent ratio	BA ratio	The quantity of the Eligible BA that is required to replace the Baseline BA to produce the same quality of foam including equivalent thermal performance. This ratio is applied to the quantity of Eligible BA that is used in the project to calculate the amount of Baseline BA that would have been used.
Carbon dioxide equivalent	CO_2e	CO_2e is a metric to compare other GHGs based on their GWP relative to CO_2 over the same timeframe. The IPCC publishes GWP values for converting all GHGs to a CO_2e basis (see “Global Warming Potential”).
Carbon offset credits	Offsets	A carbon offset is a reduction in emissions of GHG made to compensate for or to offset an emission of GHG made elsewhere (one offset = 1 MT CO_2e).

TERM	ACRONYM (if applicable)	DEFINITION
Default BA		For foam applications required to transition to a different BA as the result of a regulation, *the Default BA will be the BA that the project developer would have used instead of the Eligible BA. In these scenarios, the Default BA becomes the Baseline BA. See sections 4 and 5 for additional information regarding Default BA.*
Design specifications	Design specs	Documents such as spec sheets, formulation recipes, etc. showing the amount of BA required to produce the foam material for the project or job.
Eligible blowing agent	Eligible BA	Foam BAs which are eligible to create carbon credits under this Methodology meet the following criteria: • Low-GWP (GWP less than 30) • Low-ODP (ODP less than .01) • Is not a hydrofluorocarbon • Is not a hydrocarbon • Is not prevented from use by any regulation affecting the project
Eligible foam application		Those applications within the foam manufacturing industry for which the demonstrable adoption rate of an Eligible BA is not considered common practice (Table 1).
End of life	EOL	The emissions associated with the decommissioning recovery and destruction of the foam. Does not include the emissions associated with manufacturing and use of the foam.
Foam manufacturing		The process of combining a BA with additional chemicals to produce foam. The process may be

TERM	ACRONYM (if applicable)	DEFINITION
		conducted to produce a product either in a manufacturing facility or at a construction location.
Foam use		After the foam is manufactured (e.g., blown with the BA) the material is then “used” (e.g. insulates a refrigerator, a building, etc.). The use of a foam can extend many years after manufacturing and this methodology captures the emissions associated with the use of the product for 10 years after manufacturing.
Formulators		Also known as "Systems Supply Houses". These entities provide the "A" side and the "B" side chemicals which are then blown at a manufacturing site to produce foam products or at a construction site for buildings.
Global warming potential	GWP	Global warming potential is a relative scale translating the global warming impact of any GHG into its CO_2e over the same timeframe. This methodology references the 100-year GWPs in the IPCC Fourth Assessment Report (AR4) and, if unavailable, the GWPs from the IPCC Fifth Assessment Report (AR5). If neither are available, GWPs cited by the U.S. EPA SNAP Program shall be applied. GWPs found in this Methodology (Tables 3 and 9) shall be applied in the quantification of baseline and project emissions.
Hydrocarbon	HC	An organic compound containing only hydrogen and carbon atoms (e.g. pentane (C_5H_{12}) and propane (C_3H_8)).
Hydrofluorocarbon	HFC	A gaseous compound that contains carbon, fluorine, and hydrogen. Most common HFCs used in foam

TERM	ACRONYM (if applicable)	DEFINITION
		blowing are *HFC-134a, HFC-152a, HFC-365mfc, HFC-245fa and HFC-227ea.*
Isocyanate	ISO or "A-side"	Isocyanate is the reactive chemical used in the manufacture of Polyurethane Foams.
Meter readings		The readings from meters used to record the quantity of BA and other materials used in the foam blowing process.
Metric ton	MT	The metric unit of measurement for one carbon offset. 1 MT = 2,204.62 pounds or 1.10 US tons.
Polyol	"B-side"	Polyol is a blend of various chemicals and blowing agents to produce the foam structure and density.
Polyurethane foam	PUF	Foam created through the mix of polyurethane chemicals and a BA.
Production data		The records maintained (either from historical production data, MSDS sheets, industry standards, etc.) that accurately represent the foam production volume, the quantity of BA used, and any other relevant recordkeeping information for the baseline and project activity.
Project Activity		Transition to an Eligible BA in an Eligible Foam Application for foam manufacturing and use. See Applicability Conditions in Section 1.2.
Retail Food Refrigeration		Stand Alone Equipment and Refrigerated Food Processing and Dispensing Equipment. Stand Alone Equipment (open or with doors) where all refrigeration components are integrated and, for

TERM	ACRONYM (if applicable)	DEFINITION
		the smallest types, the refrigeration circuit is entirely brazed or welded (i.e., hermetically sealed). These systems are fully charged with refrigerant at the factory and typically require only an electric supply. Refrigerated Food Processing and Dispensing Equipment primarily process the product by combining ingredients, and mixing/ preparing the ingredients at the proper temperature. Other equipment in this category function mainly as holding tanks to deliver the product at the desired temperature or to deliver chilled ingredients for processing, mixing and preparation. These may use a refrigerant in a heat pump or utilize waste heat from the condenser unit located elsewhere. Equipment within this end-use category include but are not limited to those used to process/store: chilled and frozen beverages (carbonated and uncarbonated, alcoholic and nonalcoholic); frozen custards, gelato, ice cream Italian ice, sorbets and yogurts; milkshakes, smoothies, and whipped cream.
Significant New Alternatives Policy	SNAP	The U.S. Environmental Protection Agency's (EPA) SNAP program implements section 612 of the amended Clean Air Act of 1990, which requires EPA's continuous review of alternatives to find those that pose less overall risk to human health and the environment. Through these evaluations, SNAP generates lists of acceptable and unacceptable substitutes for each of the major industrial use sectors. The intended effect of the SNAP program is to promote a smooth transition to safer alternatives.
Sources, sinks, and reservoirs	SSRs	Sources: Any process that releases carbon into the atmosphere is known as a carbon source.

TERM	ACRONYM (if applicable)	DEFINITION
		Sinks: A natural or artificial reservoir that accumulates and stores some carbon-containing chemical compound for an indefinite period. Reservoirs: A pool of carbon that has the potential to accumulate or lose carbon over time. Generally applicable in the land use sector (aboveground biomass, belowground biomass, litter, dead wood, soil organic carbon, and wood products).
Systems supply houses		See "Formulators".

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1 BACKGROUND AND APPLICABILITY

1.1 PURPOSE

Certain industries use blowing agents (BAs) in the production of foam. These BAs contain chemicals that contribute to global warming by releasing greenhouse gases (GHGs) during manufacture, use, and end-of-life (EOL). Over the years, industry has begun a transition away from BAs that have high global warming potential (GWP) and high ozone depleting potential (ODP) toward BAs with lower GWP and low or zero ODP. However, certain foam applications have low market adoption rates for low GWP BA and that is generally a result of technical and financial barriers limiting use of low GWP options in these applications. This Methodology is meant to stimulate innovation and accelerate a transition to low GWP BAs in certain foam applications more rapidly than would otherwise occur. The Methodology is based on a robust data set from the United Nations Framework Convention on Climate Change (UNFCCC) Clean Development Mechanism (CDM) methodology AMS-III.N (Avoidance of HFC Emissions in Rigid Polyurethane Foam Manufacturing).

1.2 APPLICABILITY CONDITIONS

A transition to the use of an Eligible BA for the production of foam is considered a “Project Activity” under this Methodology.

In addition to satisfying the latest ACR program eligibility requirements as found in the ACR Standard, projects must satisfy the following conditions:

- The project is located in North America.
- The project is within an Eligible Foam Application (See Table 1).
- Other than for projects which use a Default BA, records of the Baseline BA used in the project must show a minimum of 2 years of usage of a BA with a GWP >30 prior to the Project Activity.

Table 1: Eligible Foam Applications[1]

FOAM APPLICATION	DESCRIPTION
XPS boardstock	XPS boardstock, block, and billet that is used for insulation in the following applications: roofing, walls, flooring, and pipes. Does not include XPS sheet foam applications.
Two-component rigid PU spray foam	Spray foam is a two-part polyurethane application that when combined forms a solid foam insulation; involves a gun, nozzle or straw and forms foam as the ingredient chemicals are blended together.
Rigid PU injected foam	A manufacturing process for producing component parts by injecting two or more liquid streams into a mold or part. Materials are fed into a mix-head, mixed, and forced into the mold cavity where they react, foam, cool and harden to the configuration of the cavity. Only Rigid PU injected foam used in the following sub-applications are eligible: • Marine flotation or buoyancy • Heating, Ventilation, Air Conditioning and Air Handling Systems • Refrigerated Transport – Foam used in refrigerated logistics services such as refrigerated cargo boxes and coolers • Small Retail Food Refrigeration – Includes Stand Alone Equipment and Refrigerated Food Processing and Dispensing Equipment • Large Retail Food Refrigeration – Includes large, “engineered” systems used in supermarkets and walk-in freezers • Industrial Refrigeration – Includes industrial process refrigeration and cold storage applications that employ cold storage panel insulation • Garage and entry doors
Rigid PUF residential refrigerators and freezers	Appliances used to preserve food and beverages in residential applications.

[1] See Appendix A and Tables 7 and 8 for market penetration analysis for Eligible Foam Applications.

1.3 REPORTING PERIODS

Projects shall have one reporting period which must not exceed 12 months in length. Baseline and project emissions shall be quantified (per Section 4) using the total volume of BA that would have been used in the absence of the Project Activity over a maximum of 12 months (baseline emissions) and the total volume of Eligible BA that was used during the project (project emissions) over the same corresponding time period.

1.4 CREDITING PERIODS

The crediting period shall be ten years. The Methodology's quantification approach is based upon the UNFCCC small system method which includes the manufacturing and use of the foam product. The Methodology excludes any calculation of EOL emissions. EOL emissions may be considered in future versions of this Methodology.

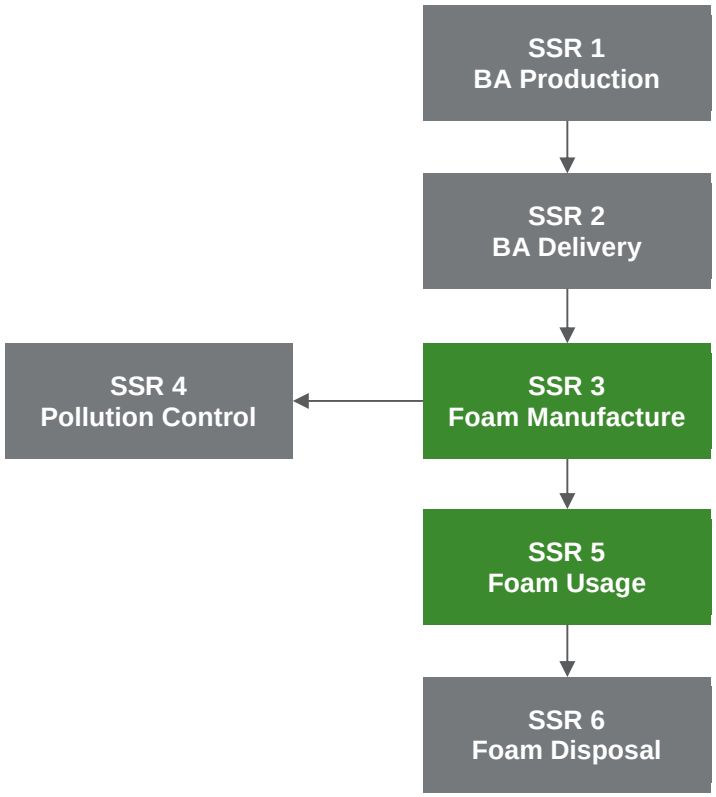
1.5 PERIODIC REVIEWS AND REVISIONS

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes to project activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the Methodology.

2 PROJECT BOUNDARIES

The project boundary delineates the sources, sinks, and reservoirs (SSRs) that must be included or excluded when quantifying the net changes in emissions associated with the transition to an Eligible BA. Figure 1 illustrates the GHG assessment boundary for a project.

Figure 1: Illustration of the Project Boundary



All SSRs in green are included and must be accounted for under this Methodology. SSRs in gray are not included under this Methodology.

Table 2: List of Identified SSRs

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFICATION METHOD
1. BA Production	Fossil fuel emissions from the production of the BA.	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	Emissions from the production of the BA.	HFC or Low GWP BA	E	N/A
2. BA Delivery	Emissions from the delivery of the BA to the project site.	HFC or Low GWP BA	E	N/A
	Fossil fuel emissions from the delivery of the BA to the project site.	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
3. Foam Manufacture	Emissions from the manufacture of the foam using a BA in the baseline and project.	HFC or Low GWP BA	I	Equations 1, 2 & 3
4. Pollution Control	Fossil fuel emissions from air pollution control equipment used in the baseline and project.	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
5. Foam Usage	Emissions from the use of the foam in the baseline and project.	HFC or Low GWP BA	I	Equations 1, 2 & 3

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFI-CATION METHOD
6. Foam Disposal	Fossil fuel emissions from the transport of the foam to EOL.	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	Emissions from the equipment used to destroy the foam at EOL	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
	Emissions from the foam at EOL (e.g. landfill, shredding, incinera-tion, etc.)	HFC or Low GWP BA	E	N/A

3 BASELINE DETERMINATION AND ADDITIONALITY

3.1 BASELINE DETERMINATION

The baseline for a project is calculated using: (1) the GWP of the Baseline BA, (2) data associated with the quantity of Eligible BA used in the project[2], and (3) the emission factor associated with the Eligible Foam Application.

As a reference, Table 3 lists some of the most common BAs currently used in North America.

Table 3: GWP of Common Baseline BAs[3]

BA	GWP[4]
HFC-152a	125
HFC-365mfc	794
HFC-245fa	1030
HFC-134a	1430

3.2 ADDITIONALITY ASSESSMENT

Emission reductions from the project must be additional, or deemed not to occur in the "business-as-usual" scenario. Assessment of the additionality of a project will be made based on passing the two tests cited below. These two tests require the project proponent to demonstrate that the project is surplus to regulations and reduces emissions below the level established in the Methodology.

- Regulatory Surplus Test
- Practice-Based Performance Standard

[2] This data is used to calculate the amount of Baseline BA that would have been used to produce a foam of equivalent thermal performance that is produced with the Eligible BA.

[3] This is not an exhaustive list but rather a guidance table for project proponents.

[4] IPCC, Fourth Assessment Report (100- year GWP time horizon).

3.2.1 Regulatory Surplus Test

In order to pass the regulatory surplus test a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect as of the start date. The project proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated with the transition to an Eligible BA.[5]

3.2.2 Practice-Based Performance Standard

For a project to qualify for offsets under this Methodology it must also be demonstrated that the Eligible Foam Application has a low market adoption rate for Eligible BAs. This Methodology has already completed a market adoption analysis, and hence an additionality demonstration for the foam applications stated in Table 1. Project proponents must only show that their project falls into one of the Eligible Foam Applications found in Table 1.

Market research showing these applications to have low market adoption rates included, but was not limited, to the following: 1) review of the EPA SNAP rule, 2) various CARB and industry research reports, 3) a market characterization study commissioned for the Methodology, and 4) conversations with various regulatory bodies and industry experts. Additional applications may be added through revisions to this Methodology. A discussion of the development of the performance standard is found in Appendix A.

[5] Project proponents should address the potential applicability of SNAP 20 and SNAP 21 regulations adopted by EPA in July 2015 and December 2016 in light of the decision by the Court of Appeals for the District of Columbia, in No. 15-1328; Executive Order 13783 (March 28, 2017, 82 FR 16093-97); and any following regulatory action by EPA.

4 QUANTIFICATION OF GHG EMISSION REDUCTIONS

Quantification of emission reductions requires the calculation of baseline emissions and project emissions using production data, the GWPs of the Baseline and Eligible BA, and the emission factor associated with the Eligible Foam Application.

The GHG emissions from the BA used in foam production occurs at three phases of the product lifecycle, (i.e. manufacturing, use, and EOL). Only manufacturing and foam use for the first 10 years are considered in this Methodology[6].

Table 4: Emission Factors for HFC-134a and HFC-152a[7]

FOAM APPLICATION	PRODUCT LIFE IN YEARS	FIRST YEAR LOSS (%)[8]	ANNUAL LOSS (%)
XPS – HFC 134a	50	25	0.75
XPS – HFC 152a	50	50	25
Rigid PUF residential refrigerators and freezers	15	7	0.5
Rigid PUF injected foam (all eligible sub-applications)	15	12.5	0.5

[6] All offsets for a project's manufacturing and use over the 10-year crediting period will be issued following verification. For example, an XPS foam production line using 100% HFC-134a (Baseline BA) with a GWP of 1430 converts to 100% of an Eligible BA with a GWP of 1 on January 1, 2017. The reporting period is January 1, 2017 through December 31, 2017. All foam produced on the foam line within that timeframe has the potential to create offsets under this Methodology, provided the required monitoring and recordkeeping is maintained. Assuming the quantity of Eligible BA used during that timeframe was 250,000 pounds and the BA ratio is 2, the emission reductions associated with the manufacturing and 10-year use of foam produced during the reporting period would be 102,935 MT CO_2e or 102,935 offsets issued, following verification.

[7] Source: Table 7.6 and Table 7.7, Page 7.37, Chapter 7: Emissions of fluorinated substitutes for Ozone depleting substances, Volume 3, Industrial Processes and Product Use, 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

[8] Includes emissions associated with the foam manufacturing.

Table 5: Emission Factors for HFC-245fa and HFC-365mfc[9]

FOAM APPLICATION	PRODUCT LIFE IN YEARS	FIRST YEAR LOSS (%)[10]	ANNUAL LOSS (%)
Rigid PUF injected foam (all eligible sub-applications)	15	10	0.5
Two-component rigid PU Spray foam	50	15	1.5
Rigid PUF residential refrigerators and freezers	15	4	0.25

4.1 BASELINE EMISSIONS

4.1.1 Baseline emissions associated with foam manufacturing and first year of foam use

These emissions are calculated as the total quantity of Baseline BA that would have been used for the foam manufacturing in absence of the Project Activity, multiplied by the first-year loss emission factor associated with the foam application (Tables 4 and 5), multiplied by the GWP of the Baseline BA. For foam applications required to transition to a different BA as the result of a regulation, the GWP of a Default BA may be used if it can be demonstrated that the Default BA is the alternative most likely to be used upon transition. Project proponents shall provide documentation, which shall include financial, market and/or technical analyses, to justify the use of the Default BA. This documentation shall be subject to review by the ACR and assessment by the chosen verification body.

[9] Source: Table 7.6 and Table 7.7, Page 7.37, Chapter 7: Emissions of fluorinated substitutes for Ozone depleting substances, Volume 3, Industrial Processes and Product Use, 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

[10] Includes emissions associated with foam manufacturing.

4.1.2 Baseline emissions associated with the remaining years of foam use

These emissions are calculated as the total quantity of Baseline BA that would have been used in the foam manufacturing in the absence of the Project Activity, multiplied by the annual loss emission factor associated with the foam application (Tables 4 and 5) multiplied by the number of years remaining in the project[11], multiplied by the GWP of the Baseline BA.

4.1.3 Calculating Baseline BA Blends

When the BA is a blend, baseline emissions are only calculated for the constituent BA that is being transitioned to the Eligible BA. In the event that each constituent of the Baseline BA is transitioned, each constituent of the Baseline BA is calculated separately.

Equation 1

$$BE_{BBA} = \{[(Q_{BBA} \times FYL_{BBA}) + (Q_{BBA} \times AL_{BBA} \times YR)] \div 2204.62\} \times GWP_{BBA}$$

WHERE

BE_{BBA}	Baseline emissions (MT CO_2e)
Q_{BBA}	The quantity of Baseline BA (in pounds) which would have been used to manufacture the foam in the absence of the project activity, using Equation 2
FYL_{BBA}	The first-year loss emission factor associated with the foam application (See Tables 4 and 5)
AL_{BBA}	The annual loss emission factor associated with the foam application (See Tables 4 and 5)
YR	The number of years remaining in the project (equal to 9 years)
2204.62	Pound to metric ton conversion
GWP_{BBA}	The GWP of the Baseline BA[12]

[11] Emission reductions are quantified over 10 years. The first-year emissions are accounted for in the first year loss emission factor, therefore, a maximum of 9 years remain to be calculated for usage emissions.

[12] For projects required to transition as a result of a regulation, the GWP of the Default BA will be used.

To calculate the quantity of Baseline BA that would have been used in the absence of the project activity, Equation 2 is applied.

Equation 2

$$Q_{BBA} = Q_{EBA} \times BAR$$

WHERE

Q_{BBA}	The quantity of Baseline BA (in pounds) which would have been used to manufacture the foam in the absence of the project activity
Q_{EBA}	The quantity of Eligible BA (in pounds) which is used to manufacture the foam for the project
BAR	Blowing Agent Ratio - The quantity of Eligible BA, as compared to the Baseline BA, that is required to replace the Baseline BA to produce a foam with equivalent thermal performance (%)

4.2 PROJECT EMISSIONS

4.2.1 Project emissions associated with foam manufacturing and first year of foam use

These emissions are calculated as the total quantity of Eligible BA that is used in the project, multiplied by the first-year loss emission factor associated with the foam application (same as the emission factor used in Equation 1), multiplied by the GWP of the Eligible BA.

4.2.2 Project emissions associated with the remaining years of foam use

These emissions are calculated using the total quantity of Eligible BA used in the project, multiplied by the annual loss emission factor associated with the foam application (same as the emission factor used in Equation 1), multiplied by the number of years remaining in the project, multiplied by the GWP of the Eligible BA.

4.2.3 Calculating Project BA Blends

When the BA is a blend, project emissions are only calculated for the Eligible BA portion of the blend.

Equation 3

$$PE_{EBA} = \{[(Q_{EBA} \times FYL_{EBA}) + (Q_{EBA} \times AL_{EBA} \times YR)] \div 2204.62\} \times GWP_{EBA}$$

WHERE

PE_{EBA}	Project emissions (MT CO_2e)
Q_{EBA}	The quantity of Eligible BA (in pounds), which is used to manufacture the foam for the project
FYL_{EBA}	The first-year loss rate emission factor of the foam application (set equal to emission factor used in Equation 1)
AL_{EBA}	The annual loss rate emission factor of the foam application (set equal to emission factor used in Equation 1)
YR	The number of years remaining in the Project Activity (9 years)
2204.62	Pound to metric ton conversion
GWP_{EBA}	The GWP of the Eligible BA

4.3 LEAKAGE

4.3.1 Market-shifting leakage emissions

Transition to an Eligible BA does not cause the displaced BA to be used elsewhere. There is no market-shifting leakage and hence is to be disregarded.

4.3.2 Activity-shifting leakage emissions

If the Project Activity results in the equipment used in the baseline being transferred to another location or activity in which a BA with a GWP greater than 30 is used, leakage effects are to be

considered. If the baseline equipment is also used in the project or is decommissioned, then leakage is to be disregarded.

- Activity shifting leakage emissions associated with the foam manufacturing and first year of foam use: These emissions are calculated as the total quantity of BA with a GWP greater than 30 that is being used at the new location with the baseline equipment, multiplied by the first year loss emission factor associated with the foam application (Tables 5 and 6), multiplied by the GWP of the BA.
- Activity shifting leakage emissions associated with the remaining years of foam use: These emissions are calculated as the total quantity of BA with a GWP greater than 30 that is being used at the new location with the baseline equipment, multiplied by the annual loss emission factor associated with the foam application (Tables 4 and 5), multiplied by the number of years remaining in the project, multiplied by the GWP of the BA.

Equation 4

$$LE_{LBA} = \{[(Q_{LBA} \times FYL_{LBA}) + (Q_{LBA} \times AL_{LBA} \times YR)] \div 2204.62\} \times GWP_{LBA}$$

WHERE

LE_{LBA}	Activity shifting leakage emissions (MT CO_2e)
Q_{LBA}	The quantity of BA (in pounds) that is used at the new location
FYL_{LBA}	The first-year loss emission factor associated with the foam application of the BA used at the new location (See Tables 4 and 5)
AL_{LBA}	The annual loss emission factor associated with the foam application of the BA used at the new location (See Tables 4 and 5)
YR	The number of remaining years in the project (9 years)
2204.62	Pound to metric ton conversion
GWP_{LBA}	The GWP of the BA used at the new location

4.4 EMISSION REDUCTIONS

The emission reductions achieved as a result of the transition to an Eligible BA are calculated as the baseline emissions minus the leakage emissions (if applicable) minus the project emissions. Annual losses beyond year ten and EOL emissions shall not be calculated.

Equation 5[13]

$$ER = ((BE_{BBA} - LE_{LBA}) - PE_{EBA}) * (1 - DF)$$

WHERE

ER	Emission reductions (MT CO_2e)
BE_{BBA}	Equation 1 - Baseline emissions (MT CO_2e)
PE_{EBA}	Equation 3 - Project emissions (MT CO_2e)
LE_{LBA}	Equation 4 - Leakage emissions (MT CO_2e)
DF	0.03 – Discount Factor (if applicable)[14]

[13] As stated in Sections 4.1 and 4.2, where a BA blend is used, emissions are to be quantified separately for each constituent BA. As a result, a summation of baseline, project, and leakage emissions for the project shall occur to accurately quantify total emission reductions associated with a project.

[14] See Footnote 15 for applicability

5 MONITORING AND DATA COLLECTION

Each project shall include a monitoring, reporting and verification plan sufficient to meet the requirements of the ACR Standard. The plan shall describe the collection of all data to be monitored and in a manner which meets the requirements for accuracy and precision of this Methodology.

This Methodology is based on determining the amount of BA that was or would have been used prior to project implementation and the amount of an Eligible BA used during the project. Project proponents are expected to provide data based on production quantity inputs to the manufacturing process (as shown in Figure 1). The Monitoring Plan shall provide inputs for all applicable equations used in this Methodology.

The project proponent is responsible for the collection and maintenance of all required data and monitoring parameters.

Individual manufacturing facilities or construction sites may be aggregated into a single project provided each of the facilities/sites meet the Applicability Conditions (1.2) and the project proponent provides the monitoring and recordkeeping as required by this Methodology.

5.1 DESCRIPTION OF THE MONITORING PLAN

The project proponent must prepare a monitoring plan describing the following:

- The location and recordkeeping/retention for all stored data.
- The methods used to generate data.
- Transfer points and methods of non-automated transfer of data.
- If applicable, describe any calibration procedures and the frequency with which calibration and other maintenance requirements are performed.
- Describe the internal audit and other quality assurance/quality control procedures.
- Sampling methods utilized and performed during the reporting period, if applicable.

The rationale for monitoring project implementation is to document all project activities implemented by the project proponent.

5.2 DATA COLLECTION AND PARAMETERS TO BE MONITORED

5.2.1 Monitoring requirements for all project types

For all projects, the process for monitoring the project's emission reduction parameters includes:

- Records documenting the foam application used in the baseline and project.
- For all foam applications, other than projects which will use the Default BA, records documenting the Baseline BA used in the project showing a minimum of 2 years of usage prior to the Project Activity.
- Records documenting the amount of the Eligible BA consumed in the Project Activity. Acceptable documentation may include any of the following, but is not limited to:
  - Weight records (in pounds) of Eligible BA material used[15,16];
  - Flow meter records of Eligible BA material used;
  - Number of products produced using the Eligible BA and the quantity (in pounds) of material in each unit manufactured;
- Records documenting the calibration of any weigh scales, flow meters, or similar measurement devices used to document the amount of Eligible BA consumed in the Project Activity.
  - Calibration must be conducted on intervals recommended by the manufacturer and documentation of calibration events shall be recorded and maintained.
- Records used in support of the BA ratio for the project including all calculations to derive the BA ratio.
- Equipment log for all equipment used in the project.

[15] For spray foam projects that only provide documentation on the amount of Eligible BA delivered (to a construction site, for example) and/or purchased for a project, a discount factor of 3.0% shall be applied in the quantification of emission reductions (see equation 5).
[16] For project types other than spray foam that supply pre-shipment weight information for the Eligible BA delivered via tanks, drums, totes, or containers, the return weight of the tanks, drums, totes, or containers shall also be provided to ensure that any "heel" remaining has been accurately deducted. Alternatively, a project (project types other than spray foam) supplying pre-shipment weight information that does not also supply the return weight may validate the pre-shipment weight of Eligible BA by providing additional evidence to the verifier to corroborate the amount of Eligible BA consumed in the project. Non-spray foam project types supplying pre-shipment weight information for the Eligible BA are not eligible to apply a discount factor in the quantification of emission reductions in lieu of sufficient evidence to confirm the amount of Eligible BA consumed in the project.

- Identification and log of any equipment modified, replaced, or decommissioned as a result of the Project Activity and any equipment moved for use outside of the project boundaries (leakage).
- For project proponents applying a Default BA: financial, market and/or technical analyses to justify the use of the Default BA.

5.2.2 Additional monitoring requirements for Formulators and/or Systems Supply Houses[17]

For projects where a Formulator or a Systems Supply House is the Project Proponent (e.g. provides the A side and B side materials as a foam system in tanks, totes, drums or other containers) the following requirements must also be met in addition to those requirements in Section 5.2.1:

- Records documenting that the foam system supplied to the foam manufacturer by the Formulator/Systems Supply House was shipped to and received by the foam manufacturer. Acceptable documentation may include, but is not limited to:
  - Bills of lading or other business records provided by the transport company as receipt of shipped material.
- Records documenting that the foam system supplied to the foam manufacturer by the Formulator/Systems Supply House was used in the application identified by the Project. Acceptable documentation may include any of the following:
  - Documentation from the Formulator/Systems Supply House;
  - Documentation from the foam manufacturer;
  - Signed attestation from the foam manufacturer.

5.2.3 Additional monitoring requirements for spray foam projects

For projects where a Formulator/Systems Supply House that is supplying spray foam is the Project Proponent (e.g. the A-side and B-side materials are supplied in tanks, totes, drums or other containers for use in Spray Foam applications) the following requirements must also be met in addition to those requirements in Section 5.2.1:

- Attestations must be obtained from distributors and contractors representing a minimum of 10 percent of the volume of Eligible BA included in the Project Activity[18].

[17] For all applications except spray foam.
[18] Attestations must be collected from a minimum of one distributor and two foam insulation contractors, per project.

- Attestations must document the following:
  - Approximate date(s) of foam production;
  - Confirmation that all A side and B side materials sent to the construction site were consumed on the date(s) specified.
- For consecutive annual or sub-annual projects, attestations may only be provided from the same distributors and contractors once every third project validation/verification.

5.2.4 Parameters Monitored

PARAMETER	BAR
Units	%
Description	(BA ratio) The quantity of Eligible BA, as compared to the Baseline BA, that is required to replace the Baseline BA to produce a foam with equivalent thermal performance
Relevant Section	4.1
Relevant Equation(s)	2
Source of Data	MSDS sheets, foam production records, meter readings, product or design specifications, engineering calculations
Measurement Frequency	Once, at the beginning of each project

PARAMETER	Q_{EBA}
Units	Pounds
Description	Quantity of Eligible BA used in project
Relevant Section	4.1 and 4.2
Relevant Equation(s)	2 and 3
Source of Data	Operating records, purchase records, usage records, meter readings

Measurement Frequency	Throughout the project

PARAMETER	**Q_{LBA}**
Units	Pounds
Description	Quantity of BA that is shifted to the new location that results in activity shifting leakage
Relevant Section	4.3
Relevant Equation(s)	4
Source of Data	Records associated with moving the equipment to a new location, operating records, purchase records, meter readings, attestations
Measurement Frequency	Throughout the project

APPENDIX A: DEVELOPMENT OF PERFORMANCE STANDARD

In developing the Methodology, information about BA use in the foam industry was gathered and reviewed. This included several studies, reports, and conversations with industry experts, regulatory personnel, and foam manufacturers. Additionally, a market research report was commissioned on the "Global Foam Blowing Agents Market Size, Share, Development, Growth, and Demand Forecast". The ACR peer review process was also relied upon to identify the market penetration of all BAs and then to identify the Eligible Foam Applications, which are shown in Methodology Table 1 and repeated below.

Table 6: Eligible Foam Applications

FOAM APPLICATION	DESCRIPTION
XPS boardstock	Boardstock, block, and billet that is used for insulation in the following applications: roofing, walls, flooring, and pipes. Does not include XPS sheet foam applications.
Two-component rigid PU spray foam	Spray foam is a two-part polyurethane application that when combined forms a solid foam insulation; involves a gun, nozzle or straw and forms foam as the ingredient chemicals are blended together.
Rigid PU injected foam	A manufacturing process for producing component parts by injecting two or more liquid streams into a mold or part. Materials for the component are fed into a mix-head, mixed, and forced into the mold cavity, where they react, foam, cool and harden to the configuration of the cavity. Only Rigid PU injected foam used in the following sub-applications are eligible: • Marine flotation or buoyancy • Heating, Ventilation, Air Conditioning and Air Handling Systems • Refrigerated Transport – Foam used in refrigerated logistics services such as refrigerated cargo boxes and coolers

FOAM APPLICATION	DESCRIPTION
	• Small Retail Food Refrigeration – Includes Stand Alone Equipment and Refrigerated Food Processing and Dispensing Equipment • Large Retail Food Refrigeration – Includes large, "engineered" systems used in supermarkets and walk-in freezers • Industrial Refrigeration – Includes industrial process refrigeration and cold storage applications that employ cold storage panel insulation • Garage and entry doors
Rigid PUF residential refrigerators and freezers	Appliances used to preserve food and beverages in residential applications.

To construct the performance standard, it was important to determine which sectors had high penetration rates for low GWP BA. Based on market research, it was determined that the following sectors already had high penetration rates for certain low GWP BA (primarily HC BA which are commonly considered to be lower GWP BA):

- PU Spray, other than two-component PU Spray
- Rigid PUF discontinuous panel
- Rigid PUF continuous laminate/boardstock
- Rigid PUF block for pipe sections
- Rigid PUF discontinuous block for panels
- Rigid PUF pipe-in-pipe
- Rigid PUF discontinuous block for pipe sections
- Rigid PUF continuous block
- XPS sheet

The primary outcome that the Methodology is meant to incentivize (reduced GHG emissions from foam BA consumption) is already being achieved in the above applications at rates that are higher than acceptable for crediting under this Methodology. Further, it was also clear that the use of HC BA should be considered business as usual for foam production. There are many additional concerns with HC BA such as high flammability risks, cost associated with flame proofing and safety measures, status as volatile organic compounds, and the generally lower thermal efficiency of foams produced by HC BA as compared to many alternatives. For these reasons, the Methodology credits only advanced formulation BAs and HC are ineligible for crediting.

Table 7 shows the market penetration rates of Eligible BAs. Table 8 shows the market penetration rates of Eligible BAs with the addition of the percentage of HC BAs consumed in these applications. As is shown, the eligible foam applications have extremely low adoption rates for Eligible BA and are also not achieving high rates of low GWP BA adoption, in general.

Table 7 Market Penetration Rate of Eligible BAs[19]

APPLICATION	2013	2014	2015	2016	2017
Rigid PUF injected foam – Marine flotation and buoyancy	1.29%	1.61%	2.04%	2.51%	2.89%
Rigid PUF injected foam – Heating, Ventilation, Air Conditioning and Air Handling Systems	2.06%	2.52%	3.21%	3.84%	4.41%
Rigid PUF injected foam – Refrigerated Transport	1.46%	1.80%	2.30%	2.77%	3.21%
Rigid PUF injected foam – Industrial Refrigeration Systems	1-2%	1-2%	1-2%	1-2%	1-2%
Rigid PUF injected foam – Retail Food Refrigeration	1.56%	1.91%	2.45%	2.88%	3.32%
Rigid PUF injected foam – Garage and Entry Doors	1.61%	2.14%	3.03%	3.88%	4.65%
Rigid PUF residential refrigerators and freezers	1.18%	1.48%	1.92%	2.34%	2.75%

[19] Eligible BAs assessed in the market analysis included all known HFOs, Methyl Formate, and inert gases.

APPLICATION	2013	2014	2015	2016	2017
XPS (Board, Billet, and Block only)	7-8%	7-8%	7-8%	7-8%	7-8%
Two-component Rigid PU Spray Foam	5%	5%	5%	5%	5%

Table 8: Market Penetration Rate including HC BAs

APPLICATION	2013	2014	2015	2016	2017
Rigid PUF injected foam – Marine flotation and buoyancy	8.21%	8.89%	9.69%	10.68%	11.89%
Rigid PUF injected foam – Heating, Ventilation, Air Conditioning and Air Handling Systems	10.54%	11.36%	12.41%	13.50%	14.84%
Rigid PUF injected foam – Refrigerated Transport	6.86%	7.41%	8.12%	8.86%	9.76%
Rigid PUF injected foam – Industrial Refrigeration Systems	7-8%	6-7%	7-8%	7-8%	7-8%
Rigid PUF injected foam – Retail Food Refrigeration	7.12%	7.72%	8.53%	9.25%	10.11%
Rigid PUF injected foam – Garage and Entry Doors	5.45%	6.90%	8.61%	10.41%	12.43%
Rigid PUF residential refrigerators and freezers	9.26%	9.63%	10.00%	10.73%	12.00%

APPLICATION	2013	2014	2015	2016	2017
XPS (Board, Billet, and Block only)	8-9%	8-9%	8-9%	8-9%	8-9%
Two-component Rigid PU Spray Foam	5%	5%	5%	5%	5%

APPENDIX B: ELIGIBLE BA GWP

The following is a table of Eligible BAs that are listed as acceptable substitutes under the SNAP program. This list is not exhaustive, it is only the list of substitutes under SNAP that are applicable to this Methodology.

Table 9: GWPs for selected Eligible BAs

ELIGIBLE BA	GWP
Methyl formate	5[20]
HFO-1336mzz(Z)	2[21]
HCFO-1233zd(E)	1[21]
CO_2	1[22]
Methylal	3[23]
HFO-1234ze	1[24]

[20] Per U.S. EPA, methyl formate's GWP is expected to be low, based on similarity to other compounds with GWPs that have been published in the peer-reviewed literature (see IPCC 4th Assessment Report, Table 2.15). Per the Federal Register, the GWP is stated to be "very low or zero" in all Federal Register listings (for methyl formate and Ecomate).For purposes of this Methodology, the GWP shall be set equal to 5 in Project emission reduction calculations.

[21] AR5

[22] AR4

[23] Per the Federal Register, the GWP is reported as less than 3. For purposes of this Methodology, the GWP shall be set equal to 3 in Project emission reduction calculations.

[24] Per AR5, the GWP is less than 1. For purposes of this Methodology, the GWP shall be set equal to 1 in Project emission reduction calculations.

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American Carbon Registry
AT WINROCK INTERNATIONAL

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

AFFORESTATION AND REFORESTATION OF DEGRADED LAND

VERSION 1.2

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May 2017

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ACRONYMS

ACR	American Carbon Registry
AFOLU	Agriculture, forestry and other land uses
A/R	Afforestation/Reforestation
BEF	Biomass expansion factor
CAI	Current annual increment
CDM	Clean Development Mechanism
CO2	Carbon dioxide
DBH	Diameter at breast height
ERT	Emission reductions tons
FAO	Food and Agriculture Organization (United Nations)
FFE	Fire and Fuels Extension Guide
FVS	Forest Vegetation Simulator
GHG	Greenhouse gas
GIS	Geographical Information System
GPG-LULUCF	Good Practice Guidance for Land Use, Land Use Change and Forestry (IPCC)
GPS	Global Positioning System
IPCC	Intergovernmental Panel on Climate Change
OF	Oxidized fraction
QA/QC	Quality assurance / Quality control
PP	Project proponent
SLF	Short lived fraction

SOC	Soil organic carbon
SOP	Standard operating procedure
UNFCCC	United Nations Framework Convention on Climate Change
USFS	United State Forest Service
VCS	Verified Carbon Standard
VVB	Validation and verification body
WWF	Wood waste

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INTRODUCTION

The American Carbon Registry (ACR) in 2010 approved the use of the Clean Development Mechanism (CDM)-approved consolidated afforestation and reforestation baseline and monitoring methodology AR-ACM0001 Version 5.0.0, "Afforestation and Reforestation of Degraded Land," for developing an afforestation/reforestation (A/R) project for registration on ACR. See http://americancarbonregistry.org/carbon-accounting/carbon-accounting/other-accepted-methodologies. (AR-ACM0001 has since been retired by CDM and replaced by AR-ACM0003.)

In March 2011, ACR published its Methodology for Afforestation and Reforestation of Degraded Land, v1.0, which represented a modification to the CDM methodology with clarifications for project registration on ACR as well as the addition of harvested wood products accounting. This methodology modification was drafted by TREES Forest Carbon Consulting, using wood products accounting methods drawn from a "Methodology for Improved Forest Management through Extension of Rotation Age" developed by Winrock International for Ecotrust and approved under the Verified Carbon Standard (VCS) as VM0003. ACR wishes to thank TREES Forest Carbon Consulting for its assistance in making the first modification.

In a second modification, the U.S. Forest Service proposed adding its Forest Vegetation Simulator (FVS) as an approved tool to estimate carbon stock changes. This modification was reviewed by the ACR AFOLU Technical Committee and is published by ACR as the Methodology for Afforestation and Reforestation of Degraded Land, v 1.1. ACR wishes to thank the U.S. Forest Service for its assistance in making the second modification.

While new methodologies are approved through a process of public consultation and scientific peer review, methodology modifications such as these are reviewed by an independent ACR Agriculture, Forestry and Other Land Use (AFOLU) Technical Committee (see http://www.americancarbonregistry.org/carbon-accounting/acr-afolu-technical-committee). Both of the above modifications were considered by this Committee and recommended for approval. Version 1.1 was posted for public comment in June 2013.

1 SOURCE, DEFINITIONS AND APPLICABILITY

1.1 SOURCE

This methodology is a revision of CDM Methodology AR-ACM0001 to include accounting for harvested wood products, as well as the incorporation of Forest Vegetation Simulator (FVS) as an approved tool to estimate carbon stock changes. The methodology structure and text is directly adapted from these methodologies:

- AR-ACM0001, Version 5.0.0, "Afforestation and reforestation of degraded land", consolidated and published by the UNFCCC CDM Executive Board;
- VM0003 "Methodology for Improved Forest Management through Extension of Rotation Age", developed by Winrock International for Ecotrust, and approved under the Verified Carbon Standard (VCS).
- Additional text on the use of FVS, drafted by the U.S. Forest Service.

For more information regarding the source methodologies and their consideration by the CDM Executive Board (the Board) please refer to http://cdm.unfccc.int/goto/ARappmeth (note that AR-ACM0001 has since been retired by CDM and replaced by AR-ACM0003). For VM0003, please refer to http://database.v-c-s.org/methodologies/methodology-improved-forest-management-through-extension-rotation-age-v12. . For Forest Vegetation Simulator, see http://www.fs.fed.us/fmsc/fvs/.

This methodology also refers to the latest approved versions of the following CDM tools, procedures, guidelines and guidances:

- Procedures to demonstrate the eligibility of lands for afforestation and reforestation CDM project activities;
- Guidance on application of the definition of the project boundary to A/R CDM project activities;
- Tool for the identification of degraded or degrading lands for consideration in implementing CDM A/R project activities;
- Combined tool to identify the baseline scenario and demonstrate the additionality in A/R CDM project activities;
- Calculation of the number of sample plots for measurements within A/R CDM project activities;
- Tool for testing significance of GHG emissions in A/R CDM project activities;

- Estimation of GHG emissions due to clearing, burning and decay of existing vegetation attributable to a CDM A/R project activity;
- Estimation of the increase in GHG emissions attributable to displacement of pre-project agricultural activities in A/R CDM project activity;
- Tool for estimation of change in soil organic carbon stocks due to the implementation of A/R CDM project activities.

All the above-mentioned tools, procedures, guidelines and guidance are available at: http://cdm.unfccc.int/Reference/tools and http://cdm.unfccc.int/Reference/Procedures/index.html.

Some sections of this methodology refer to the Forest Vegetation Simulator (FVS) as a tool to estimate carbon stock changes. FVS is the U.S. Forest Service's national forest growth model. The FVS software package is free and available on the internet. Please note that:

- The additional guidelines on using FVS in conjunction with this methodology, included in section 4, must be followed.
- When following this methodology, the latest version of the FVS software should always be used.
- FVS may only be used for projects located within the United States.

1.2 SELECTED BASELINE APPROACH

"Existing or historical, as applicable, changes in carbon stocks in the carbon pools within the project boundary"

1.3 DEFINITIONS

All definitions, eligibility requirements, and other criteria of the ACR Standard shall apply. This includes the definitions of "forest" and "Afforestation / Reforestation".

1.4 APPLICABILITY

This methodology is applicable to afforestation and reforestation ACR project activities that are implemented on degraded lands.

The conditions under which the methodology is applicable are:

I. The A/R ACR project activity is implemented on degraded lands, which are expected to remain degraded or to continue to degrade in the absence of the project, hence the land cannot be expected to revert to a non-degraded state without human intervention.
II. If at least a part of the project activity is implemented on organic soils or wetlands[1], intentional manipulation of the water table is not allowed (i.e. the project activity shall not involve manipulation of hydrology or otherwise affect hydrology), not more than 10% of their area may be disturbed as result of soil preparation for planting and species planted are restricted to those likely to have occurred under historic natural forest conditions in the project area, per best available knowledge (relevant literature and/or consultation with local experts).
III. Litter shall remain on site and not be removed in the A/R ACR project activity.
IV. Ploughing/ripping/scarification attributable to the A/R ACR project activity, if any, is:
    A. Done in accordance with appropriate soil conservation practices, e.g. follows the land contour; and
    B. Limited to the first five years from the year of initial site preparation; and
    C. Not repeated, if at all, within a period of 20 years.

The latest version of the "Tool for the identification of degraded or degrading lands for consideration in implementing CDM A/R project activities" shall be applied for demonstrating that lands are degraded or degrading.

Applicability condition I and the requirement to use the CDM tool for identification of degraded or degrading lands do not imply that there may be no remnant trees as of the project start date, or no natural regeneration in the baseline scenario. However, note the following:

- Remnant trees must be either excluded from the project boundary, if in patches large enough to exclude; or if individual remnant trees are present within the project boundary, these must be either included in both the baseline and project scenarios (using the guidance in 2.4 and 2.5) or tagged and excluded in both the baseline and project scenarios.
- Natural regeneration in the baseline scenario is expected to be minimal, such that the project lands continue to be classified as degraded or degrading. To ensure that this assumption remains valid over the Crediting Period, this methodology requires the establishment of Regeneration Monitoring Areas, outside the project boundary in areas similar to the project area but unplanted, in which baseline natural regeneration must be assessed at intervals not to exceed 10 years. See details in section 3.3.

[1] "Wetlands", "settlements", "cropland" and "grassland" are land categories as defined in the Good Practice Guidance for Land Use, Land-use Change and Forestry (IPCC, 2003)

2 BASELINE METHODOLOGY PROCEDURE

2.1 PROJECT BOUNDARY AND ELIGIBILITY OF LAND

The “project boundary” geographically delineates the afforestation or reforestation project activity under the control of the Project Proponent (PP). The A/R ACR project activity may contain more than one discrete area of land. Each discrete area of land shall have a unique geographical identification.

It shall be demonstrated that each discrete area of land to be included in the boundary is eligible for an A/R ACR project activity. PPs shall apply the “Procedures to demonstrate the eligibility of lands for afforestation and reforestation CDM project activities” as approved by the Board.

The latest version of “Guidance on application of the definition of the project boundary to A/R CDM project activities” (available at: http://cdm.unfccc.int/Reference/Guidclarif) may be applied in identification of areas of land planned for an A/R ACR project activity.

Tables 1 and 2 shall be followed in determining the GHG assessment boundary, along with the guidance in the ACR Standard. Exclusion of carbon pools and emission sources is allowed, subject to considerations of conservativeness and significance testing. Pools or sources may always be excluded if conservative, i.e. exclusion will tend to underestimate net GHG emission reductions/removal enhancements. Pools or sources may also be excluded if application of the most recent version of the CDM “Tool for testing significance of GHG emissions in A/R CDM project activities” leads to the conclusion that a particular pool or source is insignificant. Pools and sources deemed significant and/or selected for accounting in the baseline scenario shall also be accounted in the project scenario.

The carbon pools included in or excluded from accounting are shown in Table 1.

Table 1: Carbon Pools Accounted for in the Project Boundary

CARBON POOLS	ACCOUNTED FOR	JUSTIFICATION / EXPLANATION
Above-ground biomass	Yes	Major carbon pool subjected to project activity.

CARBON POOLS	ACCOUNTED FOR	JUSTIFICATION / EXPLANATION
Below-ground biomass	Yes	Below-ground biomass stock is expected to increase due to the implementation of the A/R ACR project activity.
Dead wood	Yes (alternatively No)	This stock may change (when compared to baseline) due to implementation of the project activity. The methodology provides an approach for accounting for this pool, but it also allows for exclusion of the dead wood carbon pool if transparent and verifiable information can be provided that carbon stocks in dead wood in the baseline scenario can be expected to decrease more or increase less, relative to the project scenario.
Litter	Yes (alternatively No)[2]	This stock may change (when compared to baseline) due to implementation of the project activity. The methodology provides an approach for accounting for this pool, but it also allows for exclusion of the litter carbon pool if transparent and verifiable information can be provided that carbon stocks in litter in the baseline scenario can be expected to decrease more or increase less, relative to the project scenario.
Soil organic carbon (SOC)	Yes (alternatively No if project implemented on wetlands or organic soils)	Soil disturbance resulting from site preparation, if applied on more than 10% of the project area, may cause a temporary emission from soil carbon and therefore accounting of C stock changes in this pool is required, otherwise it is optional.
Wood products	Optional	This stock may increase (when compared to baseline) due to implementation of the project activity. The methodology provides an approach for accounting for this pool, but it allows also for exclusion of the wood products pool.

The emission sources and associated GHGs included in or excluded from accounting are shown in Table 2.

[2] Note that per the ACR Standard , litter is considered a priori insignificant and thus may be excluded (or optionally included).

Table 2: Emission Sources and GHGs Included in or Excluded from Accounting

SOURCES	GAS	INCLUDED / EXCLUDED	JUSTIFICATION / EXPLANATION
Burning of woody biomass	CO_2	Excluded	Carbon stock decreases due to burning are accounted as a change in carbon stock.
	CH_4	Included	Burning of woody biomass for the purpose of site preparation or as part of forest management can lead to significant levels of emissions of methane.
	N_2O	Excluded	Potential emissions are negligibly small.

2.2 IDENTIFICATION OF THE BASELINE SCENARIO AND DEMONSTRATION OF ADDITIONALITY

Project Proponents shall demonstrate additionality through the ACR three-prong test. The CDM "Combined tool to identify the baseline scenario and demonstrate additionality in A/R CDM project activities," required by ACM0001, is required; this amplifies but does not conflict with ACR's three-prong test.

2.3 STRATIFICATION

If the project activity area is not homogeneous, stratification should be carried out to improve the accuracy and precision of biomass estimates. Different stratifications may be required for the baseline and project scenarios in order to achieve optimal accuracy of the estimates of net GHG removal by sinks. For estimation of baseline net GHG removals by sinks, or estimation of actual net GHG removals by sinks, strata should be defined on the basis of parameters that are key entry variables in any method (e.g. growth models or yield curves/tables) used to estimate changes in biomass stocks. Thus:

- **FOR BASELINE NET GHG REMOVALS BY SINKS.** It will usually be sufficient to stratify according to area of major vegetation types because baseline removals for degraded (or degrading) land are expected to be small in comparison to project removals;
- **FOR ACTUAL NET GHG REMOVALS BY SINKS.** The stratification for ex ante estimations shall be based on the project planting/management plan. The stratification for *ex post* estimations shall be based on the actual implementation of the project planting/management plan. If

natural or anthropogenic impacts (e.g. local fires) or other factors (e.g. soil type) add variability to the growth pattern of the biomass in the project area, then the ex post stratification shall be revised accordingly.

PPs may use remotely sensed data acquired close to the time of project commencement and/or the occurrence of natural or anthropogenic impacts for ex ante and ex post stratification.

PPs should treat the part of the project area which contains organic soils, if any, as a separate stratum and ensure that applicability condition II of this methodology is met in this stratum.

2.4 BASELINE NET GHG REMOVALS BY SINKS

The baseline net GHG removals by sinks is the sum of the changes in carbon stocks in the selected carbon pools within the project boundary that would have occurred in the absence of the A/R ACR project activity.

Under the applicability conditions of this methodology:

- Changes in carbon stock of above-ground and below-ground biomass of non-tree vegetation may be conservatively assumed to be zero for all strata in the baseline scenario;
- If values for carbon stocks of dead wood and litter carbon pools are readily available (for example, from the Forest Vegetation Simulator) those values may be used to estimate changes in carbon stocks in the baseline scenario. If values are not readily available, it may conservatively be assumed that the sum of the changes in the carbon stocks of dead wood and litter carbon pools is zero for all strata in the baseline scenario;
- Since carbon stock in soil organic carbon (SOC) is unlikely to increase in the baseline, the change in carbon stock in SOC may be conservatively assumed to be zero for all strata in the baseline scenario.

Therefore the baseline net GHG removals by sinks will be determined as:

Equation 1

$$\Delta C_{BSL} = \Delta C_{TREE_BSL} + \Delta C_{WP_BSL}$$

WHERE

ΔC_{BSL}	Baseline net GHG removals by sinks; MT CO_2e
ΔC_{TREE_BSL}	Sum of the carbon stock changes in above-ground and below-ground biomass of trees in the baseline; MT CO_2e

ΔC_{WP_BSL}	Carbon stock changes in wood products in the baseline; MT CO_2e

2.4.1 Carbon Stock Changes in Above-ground and Below-ground Tree Biomass (ΔC_{TREE_BSL})

The estimation of carbon stock changes in above-ground and below-ground tree biomass in the baseline (ΔC_{TREE_BSL}) will be carried out using the equations below. These equations provide for the calculations to be performed for each stratum. If there is more than one stratum in the baseline scenario, the outcome will be summed over all the strata to obtain the value for the whole project.

The carbon stock changes in above-ground and below-ground tree biomass in the baseline is estimated by one of the following methods:

Equation 2

$$\Delta C_{TREE_BSL} = \frac{44}{12} \times \Delta B_{TREE_BSL} \times CF_{TREE_BSL}$$

AND

Equation 3

$$\Delta C_{TREE_BSL} = \Delta C_{TREE_BSL_FVS} \times \frac{44}{12} \times A_{BSL}$$

WHERE

ΔC_{TREE_BSL}	Change in carbon stock in living tree biomass in baseline; MT CO_2e
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless
ΔB_{TREE_BSL}	Change in biomass of living trees in baseline; MT d.m.
CF_{TREE_BSL}	Carbon fraction of dry matter for tree biomass in baseline; MT C MT^{-1} d.m.
$\Delta C_{TREE_BSL_FVS}$	Change in carbon stock in living tree biomass in the baseline scenario from FVS. This is estimated by summing the Aboveground Live Total Carbon and the Belowground Live Carbon in the FVS stand carbon report and subtracting this value for the year at the start of the A/R ACR project activity from

	the value for a future year. Units must be changed to metric tons per hectare; MT C/ha
A_{BSL}	Area; ha

Change in biomass of living trees (ΔB_{TREE_BSL}) is estimated as follows:

Equation 4

$$\Delta B_{TREE_BSL,t} = \sum_j A_{BSL,j} \times I_{V,j,t} \times D_j \times BEF_{1,j} \times (1 + R_{l,j}) - \sum_j B_{LOSS_BSL,j,t}$$

WHERE

$\Delta B_{TREE_BSL,t}$	Change in biomass of living trees in baseline, in year t; MT d.m.
$A_{BSL,j}$	Area under trees of species or group of species j; ha
$I_{V,j,t}$	Current annual increment in stem volume of trees of species or group of species j, in year t; m^3 ha^{-1} yr^{-1}
D_j	Basic wood density for species or group of species j; MT d.m. m^{-3}
$BEF_{1,j}$	Biomass expansion factor for conversion of annual net increment (including bark) in stem biomass to increment in total above-ground tree biomass for species or group of species j; MT d.m. $(MT\ d.m.)^{-1}$
$R_{l,jj}$	Root-shoot ratio appropriate for biomass increment for species or group of species j; MT d.m. MT^{-1} d.m
$B_{LOSS_BSL,j,t}$	Loss of tree biomass of species or group of species j in year t; MT d.m.
j	1, 2, 3, … tree species or group of species in the given stratum in the baseline scenario
t	1, 2, 3, … t* years elapsed since the start of the A/R ACR project activity

If biomass increment tables are available and applicable to the species used in the project activity, these can directly be used in equation 4. Note that available data on average annual in-

crement in the stem volume of trees ($I_{V,j,t}$) may be expressed as a net average annual increment (i.e. biomass loss is already allowed for) and in such a case biomass loss ($B_{LOSS_BSL,j,t}$) shall be set to zero in equation 4 in order to avoid double counting.

On the other hand, the average annual increment in the stem volume of trees ($I_{V,j,t}$) may be the gross average annual increment, in which case biomass loss ($B_{LOSS_BSL,j,t}$) may either be conservatively assumed as zero or must be estimated on the basis of transparent and verifiable information on the rate at which pre-project activities (such as collection fuelwood or fodder, selection harvesting, mortality of trees, etc.) are reducing biomass stocks in existing live trees.

If species or group of species specific volume/biomass increment tables are not available then the product of the terms $I_{V,j,t} \times D_j \times BEF_{1,j}$ in equation 4 may be estimated by multiplying the relevant data from Table 3A.1.5 of IPCC GPG-LULUCF 2003 by the fractional value of the crown cover of the trees in the baseline. For example, if the crown cover of trees in the baseline is estimated as 10%, the project is located in Africa, the age class of the trees is >20 years, and the climate/forest type is "Moist with Short Dry Season", then the value of $I_{V,j,t} \times D_j \times BEF_{1,j}$ may be estimated as 0.10×1.3 = 0.13 MT d.m. ha^{-1} yr^{-1}.

2.4.2 Carbon Stock in Living Trees at the Start of the Project Activity

Carbon stock in living trees at the start of the project activity is calculated as follows:

Equation 5

$$C_{TREE_BSL} = \frac{44}{12} \times B_{TREE_BSL} \times CF_{TREE_BSL}$$

WHERE

C_{TREE_BSL}	Carbon stock in living trees in the baseline at the start of the project activity; MT CO_2e
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless
B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project; MT d.m.
CF_{TREE_BSL}	Carbon fraction of dry matter for tree biomass in baseline; MT C MT^{-1} d.m.

The biomass of living trees in the baseline at the start of the project activity is estimated using any one of the following methods:

2.4.2.1 ESTIMATION BASED ON EXISTING DATA

If published data is available from which biomass density per unit area for the project area can be estimated, the data may be used provided that the estimated value of biomass density per unit area does not underestimate biomass in the project area. In this case, the biomass of living trees in the baseline at the start of the project activity is calculated as:

Equation 6

$$B_{TREE_BSL} = BD_{TREE_BSL} \times A_{TREE_BSL}$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
BD_{TREE_BSL}	Tree biomass density per unit area of the project area (obtained from published literature); MT d.m. ha^{-1}
A_{TREE_BSL}	Area of land within the project boundary where living trees are standing at the start of the project activity; ha

2.4.2.2 DEFAULT ESTIMATION USING PARAMETER RATIO

Under this method one of the following parameters of the existing trees in baseline is estimated (denoted by P_{BSL} in the equation below): (a) Crown cover; (b) Basal area per hectare; and (c) Stand density index. Project area may be stratified on the basis of the variability of the parameter selected.

The biomass of living trees in the baseline at the start of the project activity is then calculated as:

Equation 7

$$B_{TREE_BSL} = \frac{P_{BSL}}{P_{FOREST}} \times B_{FOREST} \times A_{TREE_BSL} \times (1 + R_{TREE_BSL})$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
P_{BSL}	Parameter for living trees in the baseline at start of the project activity

P_{FOREST}	The same parameter for a fully stocked forest in the region/country where the project activity is located
B_{FOREST}	Biomass density of a fully stocked forest in the region/country where the project activity is located; MT d.m. ha^{-1}
A_{TREE_BSL}	Area of land within the project boundary where living trees are standing at start of the project activity; ha
R_{TREE_BSL}	Root-shoot ratio of trees in the baseline; dimensionless

Value of B_{FOREST} is obtained according to guidance provided in the relevant table in Section 2.8.

2.4.2.3 COMPLETE INVENTORY OF TREES

If the trees in the baseline are few and scattered, all the trees may be inventoried and dimensional measurements (diameter or height or both) may be carried out on them. One of the methods explained in section 2.5.1.1 of this methodology is then used for estimating the biomass of each tree. Biomass of living trees in the baseline at the start of the project is then calculated as:

Equation 8

$$B_{TREE_BSL} = \sum_{i=1}^{n} B_{TREE,i}$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
$B_{TREE,i}$	Biomass of the i^{th} tree as estimated from dimensional measurements; MT d.m.
n	Total number of living trees in the baseline at start of the project activity

2.4.2.4 INVENTORY OF TREES IN SAMPLE PLOTS

If the number of trees in the baseline scenario is too large for a complete inventory to be carried out, sample plots are laid out and dimensional measurements are carried out on the trees in these sample plots. One of the methods explained in section 2.5.1.1 of this methodology is

then used for estimating the biomass of each tree. The biomass of living trees in the baseline at the start of the project activity is then calculated as:

Equation 9

$$B_{TREE_BSL} = \frac{A_{TREE}}{A_{TREE,p}} \sum_{p} B_{TREE,p}$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
A_{TREE}	Area of land within the project boundary where living trees are standing at start of the project activity; ha
$A_{TREE,p}$	Area of sample plots where dimensional measurements are carried out on the trees; ha
$B_{TREE,p}$	Biomass of living trees in plot p as estimated from dimensional measurements; MT d.m.

2.4.2.5 ESTIMATION USING THE FOREST VEGETATION SIMULATOR (FVS)

Under this method, the Forest Vegetation Simulator is used to estimate the carbon stock in living trees at the start of the project activity. Because carbon (rather than biomass) is estimated, the equation below is used in place of equation 5.

Equation 10

$$C_{TREE_BSL} = \frac{44}{12} \times C_{TREE_BSL_FVS} \times A_{BSL}$$

WHERE

C_{TREE_BSL}	Carbon stock in living trees in the baseline at the start of the project activity; MT CO_2e
$C_{TREE_BSL_FVS}$	The carbon stock in living tree biomass in the baseline scenario from FVS. This is estimated by summing the Aboveground Live Total Carbon and the Belowground Live Carbon in the FVS stand carbon report for the year at the start of the A/R ACR project. Units must be changed to metric tons per hectare; MT C/ha

A_{BSL}	Area; ha
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless

2.4.3 Carbon Stock in Long-term Wood Products (ΔC_{WP_BSL})

Under the applicability conditions of this methodology, it can be assumed that there is no commercial timber produced on the degraded lands in the absence of the project activities. Carbon stock in long-term wood products can be assumed to be zero for the baseline scenario. Alternatively, the Forest Vegetation Simulator (FVS) may be used to produce a baseline stock.

Carbon stock change in wood products for commercial timber produced on degraded lands is estimated by one of the following methods:

Equation 11

$$\Delta C_{WP_BSL} = 0$$

AND

Equation 12

$$\Delta C_{WP_BSL} = \frac{44}{12} \times \Delta C_{WP_BSL_FVS} \times A_{BSL}$$

WHERE

ΔC_{WP_BSL}	Carbon stock changes in wood products in the baseline; MT CO_2e
$\Delta C_{WP_BSL_FVS}$	The change in carbon in wood products in the baseline scenario as estimated by FVS. This is obtained from the Merchantable Carbon Stored column of the FVS harvested products carbon report and includes both the carbon still in use and sequestered in a landfill. Units must be changed to metric tons per hectare; MT C/ha
A_{BSL}	Area; ha
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless

2.4.4 Steady State Under the Baseline Conditions

The baseline net GHG removals by sinks, if greater than zero, shall be estimated using the approach provided in section 2.4.1 until steady state is reached under the baseline conditions. Under steady state:

Equation 13

$$\Delta C_{BSL} = 0$$

WHERE

ΔC_{BSL}	Baseline net GHG removals by sinks

PPs may, on a project specific basis, assess when a steady state is reached during the crediting period. This shall be estimated on the basis of transparent and verifiable information originating as appropriate from available literature, data from comparable areas, from field measurements in the planned project area, or from other sources relevant to the baseline circumstances. If no data is available, a default period of 20 years since commencement of the ACR project activity will be applied.

2.5 ACTUAL NET GHG REMOVALS BY SINKS

Under the applicability conditions of this methodology:

- Changes in carbon stock of above-ground and below-ground biomass of non-tree vegetation may be conservatively assumed to be zero for all strata in the project scenario. This includes changes in carbon stock of above-ground and below-ground biomass of herbaceous vegetation throughout the Crediting Period, and changes in carbon stock of above-ground and below-ground woody shrub biomass following planting.
- However, some afforestation/reforestation projects involve removal of a significant volume of shrub biomass during site preparation in order to create conditions favorable to the seedling establishment and survival. In such cases, changes in carbon stock of above-ground and below-ground biomass of woody shrub biomass must be accounted at the first verification following site preparation. PPs shall use the guidance on estimation of carbon stock and change in carbon stock in shrubs from the CDM tool "Estimation of carbon stocks and change in carbon stocks of trees and shrubs in A/R CDM project activities."[3]

[3] http://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-14-v3.0.0.pdf.

The actual net GHG removals by sinks shall be estimated using the equations in this section. When applying these equations for the ex ante calculation of actual net GHG removals by sinks, PPs shall provide estimates of the values of those parameters that are not available before the start of the project. PPs should retain a conservative approach in making these estimates.

The actual net GHG removals by sinks shall be calculated as:

Equation 14

$$\Delta C_{ACTUAL} = \Delta C_P - GHG_E$$

WHERE

ΔC_{ACTUAL}	Actual net GHG removals by sinks; MT CO_2e
ΔC_P	Sum of the changes the carbon stock in the selected carbon pools within the project boundary; MT CO_2e
GHG_E	Increase in non-CO_2 GHG emissions within the project boundary as a result of the implementation of the A/R ACR project activity; MT CO_2e

2.5.1 Estimation of Changes in the Carbon Stocks

The verifiable changes in the carbon stock in the selected carbon pools within the project boundary are estimated using the following equation:[4]

Equation 15

$$\Delta C_P = \frac{44}{12} \times \sum_{t=1}^{t^*} \Delta C_t$$

WHERE

ΔC_P	Sum of the changes in carbon stock in all selected carbon pools in stratum i, since start of the project; MT CO_2e
ΔC_t	Change in carbon stock in all selected carbon pools, in year t; MT C
t	1, 2, 3, … t^* years elapsed since the start of the A/R project activity; yr

[4] IPCC GPG-LULUCF 2003, Equation 3.2.3.

$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless

Change in carbon stock in all selected carbon pools, in year t, is calculated as:

Equation 16

$$\Delta C_t = \sum_{i=1}^{M_{PS}} (\Delta C_{TREE,i,t} + \Delta C_{SHRUB,i,t} + \Delta C_{DW,i,t} + \Delta C_{LI,i,t} + \Delta C_{SOC,i,t} + \Delta C_{WP,i,t})$$

WHERE

ΔC_t	Change in carbon stock in all selected carbon pools, in year t; MT C
$\Delta C_{TREE,i,t}$	Change in carbon stock in above-ground and below-ground biomass of trees in stratum i, in year t; MT C
$\Delta C_{SHRUB,i,t}$	Change in carbon stock in shrub biomass within the project boundary in stratum i, in year t, calculated using the CDM tool "Estimation of carbon stocks and change in carbon stocks of trees and shrubs in A/R CDM project activities"; MT C
$\Delta C_{DW,i,t}$	Change in carbon stock in the dead wood carbon pool in stratum i, in year t; MT C
$\Delta C_{LI,i,t}$	Change in carbon stock in the litter carbon pool in stratum i, in year t; MT C
$\Delta C_{SOC,i,t}$	Change in carbon stock in the soil organic carbon pool in stratum i, in year t; MT C
$\Delta C_{WP,i,t}$	Change in the wood products carbon pool for stratum i, in year t (possibly average over a monitoring period); MT C
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

2.5.1.1 ESTIMATING CHANGE IN CARBON STOCK IN TREE BIOMASS ($\Delta C_{TREE,i,t}$)

The change in carbon stock in tree biomass is estimated on the basis of field measurements in permanent sample plots at a point of time in year t_1 and again at a point of time in year t_2. The rate of change of carbon stock in trees is calculated as:

Equation 17

$$dC_{TREE,i,(t_1,t_2)} = \frac{C_{TREE,i,t_2} - C_{TREE,i,t_1}}{T}$$

WHERE

$dC_{TREE,i,(t_1,t_2)}$	Rate of change in carbon stock in above-ground and below-ground biomass of trees in stratum i, for the period between year t_1 and year t_2; MT C yr^{-1}
C_{TREE,i,t_2}	Carbon stock in trees in stratum i, at a point of time in year t_2; MT C
C_{TREE,i,t_1}	Carbon stock in trees in stratum i, at a point of time in year t_1; MT C
T	Time elapsed between two successive estimations ($T= t_2 – t_1$); yr
i	1, 2, 3, … M_{PS} strata in the project scenario

Change in carbon stock in tree biomass in year t ($t_1 \leq t \leq t_2$) is then calculated as:

Equation 18

$$\Delta C_{TREE,i,t} = dC_{TREE,i,(t_1,t_2)} \times 1\ year$$

WHERE

$\Delta C_{TREE,i,t}$	Change in carbon stock in above-ground and below-ground biomass of trees in stratum i, in year t; MT C
$dC_{TREE,i,(t_1,t_2)}$	Rate of change in carbon stock in tree biomass within the project boundary during the period between a point of time in year t_1 and a point of time in year t_2; MT C yr^{-1}

Carbon stock in above-ground and below-ground tree biomass ($dC_{TREE,i,t}$) is estimated by one of the following methods as applied in year t:

- The biomass expansion factor (BEF) method;
- The allometric equation method; and
- The FVS method.

2.5.1.1.1 BEF Method

In this method, first the stem volume (the commercial volume) of standing trees is estimated. Ex ante estimations of stem volume are based on tree growth models and ex post estimations are based on field measurements. The stem volume is expanded to the above-ground tree biomass using biomass expansion factor (BEF) and basic wood density (D). Total tree biomass is then obtained by multiplying the above-ground tree biomass by (1+R) where R is the root-shoot ratio.

The following step-by-step procedure shows practical application of this method:

Step 1 This step is applied differently for ex ante and ex post estimations.

Step 1 (a) Ex ante estimation

I. For each tree species or group of species under the project scenario, select a tree growth model from existing data or literature. Available growth models could be in form of yield tables, growth curves/equations, or growth simulation models. See section 2.8 for exact guidance on selecting the growth model applicable;
II. From the growth model selected, calculate the stem volume of trees per unit area according to the project planting/management plan.

Step 1 (b) Ex post estimation

Ex post estimation of tree biomass must be based on actual measurements carried out on all trees in the permanent sample plots. The permanent sample plots are laid out according to the approved methodological tool “Calculation of the number of sample plots for measurements within A/R CDM project activities”.

The following sub-steps apply for ex post estimation:

I. Select the volume tables (these could be in form of equations or curves) applicable to the tree species or group of species planted under the project. See section 2.8 for exact guidance on selecting the volume tables applicable;
II. Depending on the volume tables selected in the sub-step above, measure the diameter at breast height (DBH) and/or tree height (H) of all trees in the permanent sample plots;

III. Insert the above field measurements into the selected volume tables and calculate the stem volume of all trees in each sample plot.

NOTE. It is also possible to combine the sub-steps (I) and (II) if a suitable field instrument (such as a Spiegel relascope) is used.

Step 2 Convert the stem volume to total carbon stock in tree biomass using the following equation:

Equation 19

$$C_{TREE,j,p,i} = V_{TREE,j,p,i} \times D_j \times BEF_{2,j} \times (1 + R_j) \times CF_j$$

WHERE

$C_{TREE,j,p,i}$	Total carbon stock in trees of species or group of species j in sample plot p in stratum i; MT C
$V_{TREE,j,p,i}$	Stem volume of trees of species or group of species j in plot p in stratum i estimated by using the diameter at breast height (DBH) and/or tree height (H) as entry data into a volume table; m^3
D_j	Basic wood density of species or group of species j; MT d.m. m^{-3}
$BEF_{2,j}$	Biomass expansion factor for conversion of stem biomass to above-ground tree biomass for species or group of species j; dimensionless
R_j	Root-shoot ratio for tree species or group of species j; dimensionless
CF_j	Carbon fraction of biomass for tree species or group of species j; MT C t^{-1} d.m.
j	1, 2, 3, … tree species or group of species in the project scenario
p	1, 2, 3, … sample plots in stratum i
i	1, 2, 3, … strata in the project scenario

2.5.1.1.2 Allometric Method

The allometric method directly calculates above-ground tree biomass without relating it to tree stem volume. The method depends upon availability of allometric equations which express above-ground tree biomass as a function of diameter at breast height (DBH) and/or tree height (H). Total tree biomass is then obtained by multiplying the above-ground tree biomass by $(1+R)$ where R is the root-shoot ratio.

The following step-by-step procedure shows how this method is practically applied:

Step 1 This step is applied differently for ex ante and ex post estimations.

Step 1 (a) Ex ante estimation

I. For each tree species or group of species, select an allometric equation from existing data or literature. See section 2.8 for exact guidance on selecting the allometric equation applicable;
II. For each tree species or group of species, select a tree growth model from existing data and literature, as explained in sub-step 1(a)(i) of the BEF method above;
III. Obtain the diameter at breast height (DBH) and/or tree height (H) corresponding to the age of tree at a given time from the tree growth model selected above;
IV. Insert the diameter at breast height (DBH) and/or tree height (H) into the allometric equation and calculate the total above-ground tree biomass per unit area according to the project planting/management plan.

Step 1 (b) Ex post estimation

Ex post estimation of tree biomass must be based on actual measurements carried out on all trees in the permanent sample plots. The permanent sample plots are laid out according to the approved methodological tool “Calculation of the number of sample plots for measurements within A/R CDM project activities”.

The following sub-steps apply for ex post estimation.

I. Select an allometric equation for the tree species or group of species as described in sub-step 1(a)(i) above;
II. Depending on the allometric equation, measure the diameter at breast height (DBH) and/or tree height (H) of all trees in the permanent sample plots;
III. Insert the above measurements into the allometric equation and calculate the total above-ground tree biomass for each sample plot.

Step 2 Convert the above-ground tree biomass to total carbon stock in tree biomass using the following equation:

Equation 20

$$C_{TREE,j,p,i} = f_j(DBH, H) \times (1 + R_j) \times CF_j$$

WHERE

$C_{TREE,j,p,i}$	Total carbon stock in trees of species or group of species j in sample plot p in stratum i; MT C
CF_j	Carbon fraction of biomass for tree species or group of species j; MT C (MT d.m.)$^{-1}$
$f_j(DBH, H)$	Above-ground biomass of trees of species or group of species j in sample plot p calculated using allometric function returning total above-ground tree biomass on the basis of breast height (DBH) and/or height of the tree (H); MT d.m.
R_j	Root-shoot ratio for tree species or group of species j; dimensionless
j	1, 2, 3, … tree species or group of species in the project scenario
p	1, 2, 3, … sample plots in stratum i
i	1, 2, 3, … strata in the project scenario

FOR BOTH THE BEF METHOD AND THE ALLOMETRIC EQUATION METHOD, the total carbon stock in tree biomass for each stratum is calculated as follows:

Equation 21

$$C_{TREE,i} = \frac{A_i}{A_{p,i}} \sum_{p=1}^{P_i} \sum_{j=1}^{J_i} C_{TREE,j,p,i}$$

WHERE

$C_{TREE,i}$	Carbon stock in trees in stratum i; MT C

$C_{TREE,j,p,i}$	Carbon stock in trees of species or group of species **j** in plot *p* of stratum **i**; MT C
$A_{p,i}$	Total area of sample plots in stratum **i**; ha
A_i	Total area of stratum **i**; ha
j	1, 2, 3, … J_i species or group of species of trees in stratum **i**
p	1, 2, 3, … P_i sample plots in stratum **i** in the project scenario
i	1, 2, 3, … M_{PS} strata in the project scenario

Equation 18 when applied at two consecutive years t_1 and t_2 (e.g. two consecutive verification years) provides two values C_{TREE,i,t_1} and C_{TREE,i,t_2} which are then inserted in equation 14.

2.5.1.1.3 FVS Method

The FVS method uses the Forest Vegetation Simulator (FVS) to calculate aboveground and belowground tree biomass. For ex ante estimation, carbon estimates for initial and future years can be obtained from an FVS simulation done for each stratum. For ex post estimation, measurements from permanent sample plots can be entered into FVS and carbon estimates obtained for the year the plot data was collected with an FVS simulation for each stratum. The permanent sample plots are laid out according to the approved methodological tool "Calculation of the number of sample plots for measurements within A/R CDM project activities". In both cases, the units for the FVS stand carbon report must be changed to metric tons per hectare.

The total carbon stock in tree biomass for each stratum is calculated as follows:

Equation 22

$$C_{TREE,i} = A_i \times C_{TREE,i_FVS}$$

WHERE

$C_{TREE,i}$	Carbon stock in trees in stratum **i**; MT C
C_{TREE,i_FVS}	Carbon stock in trees for stratum **i** using FVS. This is estimated by summing the Aboveground Live Total Carbon and the Belowground Live Carbon in the FVS stand carbon report for a particular year. Units must be changed to metric tons per hectare; MT C/ha

A_i	Total area of stratum **i**; ha
i	1, 2, 3, … M_{PS} strata in the project scenario

Equation 22 when applied at two consecutive years t_1 and t_2 provides two values C_{TREE,i,t_1} and C_{TREE,i,t_2} which are then inserted in equation 17.

NOTE. At start of the project activity (that is for t_1=1) the baseline tree biomass is equal to initial biomass under the project, that is, the value of C_{TREE,i,t_1} in equation 17 is set equal to the baseline C stock as calculated in equation 5.

2.5.1.2 DEAD WOOD
(IF SELECTED IN TABLE 1)

For ex ante estimates, if values for carbon stocks of dead wood are readily available (for example, from the Forest Vegetation Simulator) those values may be used. If values are not readily available, the changes in carbon stocks of dead wood shall be conservatively neglected.

Dead wood included in the methodology comprises two components only—standing dead wood and lying dead wood (that is, below-ground dead wood is conservatively neglected). Considering the differences in the two components, different sampling and estimation procedures shall be used to calculate the changes in dead wood biomass of the two components.

For the ex post situation, the rate of change in C stock in dead wood is estimated as follows:

Equation 23

$$dC_{DW,i,t} = \frac{C_{DW,i,t_2} - C_{DW,i,t_1}}{T}$$

WHERE

$dC_{DW,i,t}$	Rate of change in carbon stock in dead wood in stratum **i**, for the period between year t_1 and year t_2; MT C yr^{-1}
$C_{DW,i,t}$	Carbon stock of dead wood in stratum **i**, at time **t**; MT C
T	Number of years between monitoring time t_2 and t_1 ($T = t_2 - t_1$); yr
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Change in carbon stock in dead wood in year t ($t_1 \leq t \leq t_2$) is then calculated as:

Equation 24

$$\Delta C_{DW,i,t} = dC_{DW,i,(t_1,t_2)} \times 1\ year$$

WHERE

$\Delta C_{DW,i,t}$	Change in carbon stock in dead wood in stratum i, in year t; MT C
$dC_{DW,i,(t_1,t_2)}$	Rate of change in carbon stock in dead wood in stratum i, for the period between year t_1 and year t_2; MT C yr^{-1}

Carbon stock of dead wood in stratum i, at time t is estimated by one of the following methods:

Equation 25

$$C_{DW,i,t} = \left(B_{SDW,i,t} + B_{LDW,i,t}\right) \times CF_{DW}$$

AND

Equation 26

$$C_{DW,i,t} = C_{SDW,i,t,FVS} \times A_i + \left(B_{LDW,i,t}\right) \times CF_{DW}$$

WHERE

$C_{DW,i,t}$	Carbon stock of dead wood biomass in stratum i, at a point of time in year t; MT C
$B_{SDW,i,t}$	Biomass of standing dead wood in stratum i, at a point of time in year t; MT d.m.
$B_{LDW,i,t}$	Biomass of lying dead wood in stratum i, at a point of time in year t; MT d.m.
CF_{DW}	Carbon fraction of dead wood biomass; dimensionless
i	1, 2, 3, … MPS strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

$C_{SDW,i,t,FVS}$	Carbon of standing dead wood in stratum **i**, in year **t** from FVS. This is from the Standing Dead Carbon column in the FVS stand carbon report. Units must be changed to metric tons per hectare; MT C/ha
A_i	Total area of stratum **i**; ha

The methods to be followed in the measurement of the standing dead wood and the lying dead wood biomass are outlined below.

2.5.1.2.1 Standing Dead Wood

Step 1 Standing dead trees shall be measured on permanent sample plots (established for estimating tree biomass - see 2.5.1.1 above) using the same criteria and monitoring frequency used for measuring living trees. The decomposed portion that corresponds to the original above-ground and below-ground biomass is discounted.

Step 2 The decomposition class of the dead tree and the diameter at breast height shall be recorded and the standing dead wood is categorized under the following four decomposition classes:

CLASS 1. Tree with branches and twigs that resembles a live tree (except for leaves);
CLASS 2. Tree with no twigs, but with persistent small and large branches;
CLASS 3. Tree with large branches only;
CLASS 4. Bole only, no branches.

Step 3a For tree in the decomposition class 1 biomass should be estimated using the allometric equation for living trees.

Step 3b When the bole is in decomposition classes 2, 3 or 4, it is recommended to limit the estimate of the biomass to the main trunk of the tree. Usually, there are no allometric equations applicable for such boles and their biomass is estimated based on volume assessment. The volume of dead wood is converted to biomass using the dead wood density appropriate for the decomposition class.

2.5.1.2.2 Lying Dead Wood

The lying dead wood pool is highly variable, and stocks increase as the stands grow; hence its monitoring may be taken up in the first, second or subsequent monitoring periods. The volume of lying dead wood can be assessed from the following survey.

Step 1 Lying dead wood should be sampled using the line intersect method (Harmon and Sexton, 1996).[5] Two 50-m lines bisecting each plot are established and the diameters of the lying dead wood (≥5 cm diameter) intersecting the lines are measured.

Step 2 The dead wood is assigned to one of the three density states $ds=1$ (sound), $ds=2$ (intermediate), and $ds=3$ (rotten) using the 'machete test', as recommended by IPCC Good Practice Guidance for LULUCF (2003), Section 4.3.3.5.3.

Step 3 The volume of lying dead wood per unit area is calculated using the equation (Warren and Olsen, 1964)[6] as modified by van Wagner (1968)[7] separately for each density state:

Equation 27

$$V_{LDW,i,t} = \frac{\pi^2 \times \left(\sum_{n=1}^{N} D_{n,i,t}^{\ 2}\right)}{8 \times L}$$

WHERE

$V_{LDW,i,t}$	Volume of lying dead wood per unit area in stratum i, at time t; m^3 ha^{-1}
$D_{n,i,t}$	Diameter of piece n of dead wood along the transect in stratum i, at time t; cm
N	Total number of wood pieces intersecting the transect; dimensionless
L	Length of the transect; m

[5] Harmon, M. E. and J. Sexton. (1996) Guidelines for Measurements of Woody Detritus in Forest Ecosystems. US LTER Publication No. 20. US LTER Network Office, University of Washington, Seattle, WA, USA.

[6] Warren, W.G. and Olsen, P.F. (1964) A line transect technique for assessing logging waste, Forest Science 10: 267-276.

[7] Van Wagner, C. E. (1968): The line intersect method in forest fuel sampling. Forest Science 14: 20-26.

i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Step 4 Volume of lying dead wood shall be converted into biomass using the following relationship.

Equation 28

$$B_{LDW,i,t} = A_i \times \sum_{ds=1}^{3} V_{LDW,i,t} \times D_{DW,ds}$$

WHERE

$B_{LDW,i,t}$	Biomass of lying dead wood in stratum i at time t; t d.m.
$V_{LDW,i,t}$	Volume of lying dead wood in stratum i, at time t; m^3 ha^{-1}
$D_{DW,ds}$	Basic wood density of dead wood in the density class ds; t d.m. m^{-3} **NOTE:** To estimate density of each class, follow the procedure described in IPCC Good Practice Guidance for LULUCF (2003), Section 4.3.3.5.3.
A_i	Area of stratum i; ha
ds	Index for density state: 1 (sound), 2 (intermediate) or 3 (rotten)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

2.5.1.3 LITTER
(IF SELECTED IN TABLE 1)

For ex ante estimates, if values for carbon stocks of litter are readily available (for example, from the Forest Vegetation Simulator) those values may be used. If values are not readily available, the changes in carbon stocks of litter shall be conservatively neglected.

For ex post estimates, four litter samples shall be collected per sample plot and well mixed into one composite sample. Samples shall be taken at the same time of the year in order to account for natural and anthropogenic influences on the litter accumulation and to eliminate seasonal effects.

A sub-sample from the composite sample of litter is taken, oven dried and weighed to determine the dry weight. The dry to wet weight ratio of the sub-sample is calculated and used for estimations of the litter dry weight.

To estimate the dry litter biomass in metric tons per hectare, the wet litter biomass for the sample plots is multiplied by the dry to wet weight ratio and an expansion factor for the plot size to calculate the litter biomass in metric tons per hectare (10,000 m^2/4 × area of sampling frame in m^2):

Equation 29

$$B_{LI,i,p} = 2.5 \times B_{LI_WET,i,p} \times \frac{MP_{LI}}{a_{i,p}}$$

WHERE

$B_{LI,i,p}$	Biomass of dry litter for plot p in stratum i; MT d.m. ha^{-1}
$B_{LI_WET,i,p}$	Wet weight (field) of the litter in plot p of stratum i; kg
MP_{LI}	Dry-to-wet weight ratio of the litter (dry weight/wet weight); dimensionless
$a_{i,p}$	Area of sampling frame for plot p in stratum i; m^2
i	1, 2, 3, … M_{PS} strata in the project scenario
p	Index for sample plots

The average annual rate of change in the carbon stock of litter from the data at two monitoring intervals shall be calculated. As recommended in the Good Practice Guidance on LULUCF (Chapter 3.2, p 3.35), the dry mass of litter is converted into carbon using 0.370 MT C MT^{-1} d.m. as a default value for the carbon fraction.8 Thus:

[8] Smith and Heath, 2002.

Equation 30

$$dC_{LI,i,t} = \frac{B_{LI,i,t_2} - B_{LI,i,t_1}}{T} \times CF_{LI}$$

WHERE

$dC_{LI,i,t}$	Rate of change in the litter carbon pool in stratum i (averaged over a monitoring period); MT C yr^{-1}
$B_{LI,i,t}$	Biomass of litter in stratum i at time t; MT d.m.
T	Number of years between monitoring time t_2 and t_1 $(T = t_2 - t_1)$; yr
CF_{LI}	Carbon fraction of litter (default value 0.370 MT C MT^{-1} d.m.); MT C MT^{-1} d.m.
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Change in carbon stock in litter in year t ($t_1 \leq t \leq t_2$) is then calculated as:

Equation 31

$$\Delta C_{LI,i,t} = dC_{LI,i,(t_1,t_2)} \times 1 \text{ year}$$

WHERE

$\Delta C_{LI,i,t}$	Change in carbon stock in litter in stratum i, in year t; MT C
$dC_{LI,i,(t_1,t_2)}$	Rate of change in carbon stock in litter in stratum i, for the period between year t_1 and year t_2; MT C yr^{-1}

2.5.1.4 SOIL ORGANIC CARBON
(IF SELECTED IN TABLE 1)

For ex ante estimations, the changes in stocks of soil organic carbon may be assessed using the default method or the changes may be conservatively neglected.

For ex post estimations, the changes in stocks of soil organic carbon are estimated using the approved methodological tool “Tool for estimation of change in soil organic carbon stocks due to the implementation of A/R CDM project activities”. That is:

Equation 32

$$\Delta C_{SOC,i,t} = \Delta SOC_{AL,t}$$

WHERE

$\Delta C_{SOC,i,t}$	Change in carbon stock in the SOC pool in stratum i, in year t; MT C
$\Delta SOC_{AL,t}$	Change in carbon stock in the SOC pool as estimated in the tool "Tool for estimation of change in soil organic carbon stocks due to the implementation of A/R ACR project activities" applied to stratum i; MT C

2.5.1.5 WOOD PRODUCTS
(IF SELECTED IN TABLE 1)

Wood products may be excluded from the project as this carbon stock is considered to be zero in the baseline scenario (see Section 2.4.3) and omission is thus always conservative. However, if included in the project scenario, wood products (if any) must also be included in accounting for the baseline scenario.

The change in carbon stock in wood products is estimated on the basis of harvested volume and ratios of long-term wood products of time in year t_1 and again at a point of time in year t_2 for each stratum. If harvesting boundaries extend across stratum boundaries, harvest volumes should be allocated to each stratum proportionally to the area harvested in each stratum and documentation thereof presented for verification. The rate of change of carbon stock in wood products is calculated as:

Equation 33

$$\Delta C_{WP,i,t} = \frac{C_{WP,i,t_2} - C_{WP,i,t_1}}{T}$$

WHERE

$\Delta C_{WP,i,t}$	Rate of change in long-term wood products from stratum *i*, averaged for the period between year t_1 and year t_2; MT C yr^{-1}
C_{WP,i,t_2}	Carbon stock in wood products from stratum i, up to year t_2; MT C
C_{WP,i,t_1}	Carbon stock in wood products from stratum i, up to year t_1; MT C
T	Time elapsed between two successive estimations $(T=t_2 - t_1)$; yr

i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

To calculate wood products two methodologies are available. The direct (1605b) method is only applicable within the 48 contiguous United States and for limited vegetation types. The less direct (Winjum et al.) method can be applied to any vegetation types throughout the world.

2.5.1.5.1 The 1605b Method

This method calculates the carbon extracted from the start of the project to date and then calculates the proportion of that carbon sequestered long term in wood products.

Step 1 Calculate the biomass of the total volume extracted from the start of the project to date from within the project boundary with extracted timber differentiated into sawnwood and pulpwood classes (if necessary convert volumes in ft^3 to m^3 by multiplying by 0.0283). When using the Forest Vegetation Simulator to estimate the change in carbon stock in wood products, this step can be skipped since these calculations are built into FVS.

Equation 34

$$EXC_{WP,i,t,s/p} = \sum_{h=1}^{H_{PS}} \sum_{j=1}^{S_{PS}} (V_{ex,i,h,s/p,j} \times D_j \times CF_j$$

WHERE

$EXC_{WP,i,t,s/p}$	The summed stock of extracted biomass carbon from stratum i up to year t by wood product disposition (sawnwood/pulpwood) s/p; MT C
$V_{ex,i,h,s/p,j}$	The volume of timber extracted from stratum i during harvest h by species j and wood product disposition (sawnwood/pulpwood) s/p; m^3
D_j	Basic wood density of species j; MT d.m. m^{-3}
CF_j	Carbon fraction of biomass for tree species j; MT C MT^{-1} d.m. (IPCC default value = 0.5 MT C MT^{-1} d.m.)

h	1, 2, 3, …H_{PS} number of harvests since the start of the A/R ACR project activity up to year t
j	1, 2, 3, … S_{PS} tree species in the baseline scenario
s/p	Wood product disposition – defined here as sawnwood or pulp-wood
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Step 2 Calculate the carbon in extracted timber that remains sequestered after 100 years. This can be done in one of two ways. Equation 35 uses Table 1.6 from the Forestry Appendix of the Technical Guidelines of the US Department of Energy's Voluntary Reporting of Greenhouse Gases Program (known as Section 1605b)[9]. PPs will determine the region the project is located in (using Figure 1.1 of the same document) and whether the timber is softwood or hardwood. Instead of tracking annual emissions through retirement, burning and decomposition, the methodology calculates the proportion of wood products that have not been emitted to the atmosphere 100 years after harvest and assumes that this proportion is permanently sequestered. The proportions defined as "In Use" and "Landfill" 100 years after production will be used here.

Equation 36 uses the Forest Vegetation Simulator to estimate the carbon sequestered over time in extracted timber.

Equation 35

$$C_{WP,i,t} = \sum_{s,p}^{s/p} EXC_{WP,i,t,s/p} \times 1605b$$

AND

Equation 36

$$C_{WP,i,t} = C_{WP,i,t,FVS} \times A_i$$

[9] http://www.eia.doe.gov/oiaf/1605/Forestryappendix[1].pdf; also available as a US Forest Service General Technical Report at: http://www.fs.fed.us/ne/durham/4104/papers/ne_gtr343.pdf

WHERE

$C_{WP,i,t}$	Carbon stock in wood products from stratum i up to year t; MT C
$EXC_{WP,i,t,s/p}$	The summed stock of extracted biomass carbon from stratum i up to year t by wood product disposition (sawnwood/pulpwood) s/p; MT C
$1605b$	The proportions of extracted timber still "in use" or sequestered in a "landfill" as wood products 100 years after production from Table 1.6 of the Forestry Appendix to the Technical Guidelines; MT C in products permanently sequestered MT C^{-1} extracted biomass carbon
s/p	Wood product disposition – defined here as sawnwood (s) or pulpwood (p)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity
$C_{WP,i,t,FVS}$	The carbon in wood products from stratum i up to year t as estimated by FVS. This is obtained from the Merchantable Carbon Stored column of the FVS harvested products carbon report and includes the carbon in wood products still in use and sequestered in a landfill. Because FVS is estimating the amount of carbon currently stored for a given year, and not necessarily the amount that is permanently sequestered, values used from the FVS report should be for the year 100 years after the harvest immediately preceding year t and the simulation should not include any harvests or thinnings that are planned to occur after year t. Units must be changed to metric tons per hectare; MT C/ha
A_i	Total area of stratum i; ha

2.5.1.5.2 The Winjum et al. Method

Step 1 Calculate the biomass of the total volume extracted from the start of the project to date from within the project boundary (if necessary convert volumes in ft^3 to m^3 by multiplying by 0.0283):

Equation 37

$$EXC_{WP,i,t,ty} = \sum_{h=1}^{H_{PS}} \sum_{j=1}^{S_{PS}} (V_{ex,i,h,ty,j} \times D_j \times CF_j$$

WHERE

$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product *ty*; MT C
$V_{ex,i,h,ty,j}$	The volume of timber extracted from stratum i during harvest h by species j and wood product class ty; m^3
D_j	Basic wood density of species j; MT d.m. m^{-3}
CF_j	Carbon fraction of biomass for tree species j; MT C MT^{-1} d.m. (IPCC default value = 0.5 MT C MT^{-1} d.m.)
h	1, 2, 3, … H_{PS} number of harvests since the start of the A/R ACR project activity up to year t.
j	1, 2, 3, … S_{PS} tree species in the baseline scenario
ty	Wood product class – defined here as sawnwood, wood-based panels, other industrial roundwood, paper and paper board, and other
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Step 2 Calculate the proportion of extracted timber that remains sequestered after 100 years. Instead of tracking annual emissions through retirement, burning and decomposition, the methodology calculates the proportion of wood products that have not been emitted to the atmosphere 100 years after harvest and assumes that this proportion is permanently sequestered. Default factors listed below are derived from Winjum et al.1998[10]. Alternatively, Project Proponents may use

[10] Winjum, J.K., Brown, S. and Schlamadinger, B. 1998. Forest harvests and wood products: sources and sinks of atmospheric carbon dioxide. Forest Science 44: 272-284

specific factors in equations 38 to 41 from local, regional or national sources that can be validated by peer-reviewed literature.

Equation 38

$$C_{WP,i,t} = \sum_{s,w,oir,p,o}^{ty} (((EXC_{WP,i,t,ty} - WW_{i,t}) - SLF_{i,t}) - OF_{i,t}$$

WHERE

$C_{WP,i,t}$	Carbon stock in wood products from stratum i up to year t; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
$SLF_{i,t}$	Fraction of wood products up to year t that will be emitted to the atmosphere within 5 years of timber harvest; MT C
$OF_{i,t}$	Fraction of wood products up to year t that will be emitted to the atmosphere between 5 and 100 years of timber harvest; MT C
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

WOOD WASTE FRACTION (WW)

Winjum et al 1998 indicate that the proportion of extracted biomass that is oxidized (burning or decaying) from the production of commodities to be equal to 19% for developed countries, 24% for developing countries.

WW is therefore equal to:

Equation 39

$$WW_{i,t} = EXC_{WP,i,t,ty} \times wf$$

WHERE

$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
wf	Wood waste fraction – 0.19 for developed countries, 0.24 for developing countries; MT C MT C^{-1}
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

SHORT-LIVED FRACTION (SLF)

Winjum et al 1998 give the following proportions for wood products with short-term (<5 yr) uses (applicable internationally):

Sawnwood	0.2
Woodbase panels	0.1
Other industrial roundwood	0.3
Paper and Paperboard	0.4

The methodology makes the assumption that all other classes of wood products are 100% oxidized within 5 years.

SLF is therefore equal to:

Equation 40

$$SLF_{i,t} = \left(EXC_{WP,i,t,ty} - WW_{i,t}\right) \times slp$$

WHERE

$SLF_{i,t}$	Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere within 5 years of timber harvest; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
slp	Short-lived proportion - 0.2 for sawnwood, 0.1 for woodbase panels, 0.3 for other industrial roundwood, 0.4 for paper and paperboard and 1 for other; MT C MT C^{-1}
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

ADDITIONAL OXIDIZED FRACTION (OF)

Winjum et al 1998 gives annual oxidation fractions for each class of wood products split by forest region (boreal, temperate and tropical). This methodology projects these fractions over 95 years to give the additional proportion that is oxidized between the 5th and 100th years after initial harvest (Table 3):

Table 3: Proportion of Remaining Wood Products

Oxidized between 5 and 100 years after initial harvest by wood product class and forest region Wood Product Class.

WOOD PRODUCT CLASS	BOREAL	TEMPERATE	TROPICAL
Sawnwood	0.36	0.60	0.84
Woodbase panels	0.60	0.84	0.97
Other industrial roundwood	0.84	0.97	0.99
Paper and paperboard	0.36	0.60	0.99

OF is therefore equal to:

Equation 41

$$OF_{i,t} = \left((EXC_{WP,i,t,ty} - WW_{i,t}) - SLF_{i,t}\right) \times fo$$

WHERE

$OF_{i,t}$	Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere between 5 and 100 years of timber harvest; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
$SLF_{i,t}$	Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere within 5 years of timber harvest; MT C
fo	Fraction oxidized – see Table 3 for defaults; MT C MT C^{-1}
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

2.5.2 Estimation of GHG Emissions within the Project Boundary

The increase in GHG emissions as a result of the implementation of the proposed A/R ACR project activity within the project boundary can be estimated as:

Equation 42

$$GHG_E = \sum_{t=1}^{t^*} E_{BIOMASS_BURN,t}$$

WHERE

GHG_E	Increase in GHG emissions as a result of the implementation of the proposed A/R ACR project activity within the project boundary; MT CO_2e
$E_{BIOMASS_BURN,t}$	Non-CO_2 emissions due to burning of biomass of existing woody vegetation as part of site preparation during the year **t**, as estimated in the tool "Estimation of GHG emissions due to clearing, burning and decay of existing vegetation attributable to a CDM A/R project activity"; MT CO_2e
t	1, 2, 3, … **t*** years elapsed since the start of the A/R ACR project activity

2.6 LEAKAGE

Under applicability conditions of this methodology the following types of leakage emissions can occur: GHG emissions due to activity displacement, the activity displaced being agricultural activities. Therefore, leakage is estimated as follows:

Equation 43

$$LK = \sum_{t=1}^{t^*} LK_{AGRIC,t}$$

WHERE

LK	Total GHG emissions due to leakage; MT CO_2e
$LK_{AGRIC,t}$	Leakage due to the displacement of agricultural activities in year **t**, as calculated in the tool "Estimation of the increase in GHG emissions attributable to

	displacement of pre-project agricultural activities in A/R CDM project activity"; MT CO_2e

2.7 NET ANTHROPOGENIC GHG REMOVALS BY SINKS

The net anthropogenic GHG removals by sinks is the actual net GHG removals by sinks minus the baseline net GHG removals by sinks minus leakage, therefore, the following general formula can be used to calculate the net anthropogenic GHG removals by sinks of an A/R ACR project activity ($C_{AR\text{-}ACR}$), in t CO_2e.

Equation 44

$$C_{AR-ACR} = \Delta C_{ACTUAL} - \Delta C_{BSL} - LK$$

WHERE

C_{AR-ACR}	Net anthropogenic GHG removals by sinks; MT CO_2e
ΔC_{ACTUAL}	Actual net GHG removals by sinks; MT CO_2e
ΔC_{BSL}	Baseline net GHG removals by sinks; MT CO_2e
LK	Total GHG emissions due to leakage; MT CO_2e

In addition an uncertainty deduction, if required per the ACR Standard (i.e. if the precision target of ±10% of the mean at 90% confidence, applied to the final calculation of emission reductions/removal enhancements, is not achieved), must be applied to the result from equation 44 to give an adjusted value of $C_{AR\text{-}ACR}$ accounting for uncertainty.

2.7.1 Calculation of ERTs

To estimate the ERTs at time $t^* = t_2$ (the date of verification) for the monitoring period $T = t_2 - t_1$, this methodology uses the equation provided by ACR[11], which uses a buffer pool and other approved mechanisms to mitigate the risk of reversals. ACR does not award temporary credits.

[11] ACR clarifications for AR-ACM0001 v5, available at http://www.americancarbonregistry.org/carbon-accounting/AR-ACM0001%20v5%20clarificaitons%20for%20use%20on%20ACR.pdf

ERTs shall be calculated by applying the buffer deduction, if applicable:

Equation 45

$$\mathbf{ERT_t = \left(C_{AR-ACR,t_2} - C_{AR-ACR,t_1}\right) \times (1 - BUF)}$$

WHERE

ERT_t	Number of Emission Reduction Tonnes at time $t=t_2-t_1$
C_{AR-ACR,t_2}	Cumulative total net GHG emission reductions up to time t_2; MT CO_2e
C_{AR-ACR,t_1}	Cumulative total net GHG emission reductions up to time t_1; MT CO_2e
BUF	Percentage of project ERTs contributed to the ACR buffer pool, if applicable

Per the ACR Standard, BUF is determined using an ACR-approved risk assessment tool.[12] If the Project Proponent elects to make the buffer contribution in non-project ERTs, or elects to mitigate the assessed reversal risk using an alternate risk mitigation mechanism approved by ACR, BUF shall be set equal to zero.

2.8 DATA AND PARAMETERS NOT MONITORED

(DEFAULT OR POSSIBLY MEASURED ONE TIME)

In addition to the parameters listed in the tables below, the provisions on data and parameters in the tools referred to in this methodology apply.

In choosing key parameters or making important assumptions based on information that is not specific to the project circumstances, such as in use of existing published data, PPs should retain a conservative approach: that is, if different values for a parameter are equally plausible, a value that does not lead to over-estimation of net anthropogenic GHG removals by sinks should be selected.

DATA / PARAMETER	$BEF_{2,j}$
DATA UNIT	Dimensionless

[12] As described in the ACR Standard, unless/until ACR publishes its own Tool for Risk Analysis and Buffer Determination, the Project Proponent shall use the latest version of the VCS AFOLU Non-Permanence Risk Tool, available at http://v-c-s.org/program-documents.

USED IN EQUATIONS	19
DESCRIPTION	Biomass expansion factor for conversion of stem biomass to above-ground biomass for tree species or group of species j
SOURCE OF DATA	The source of data shall be selected, in order of preference, from the following: • Local sources of species or group of species-specific data; • National sources of species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species; • IPCC default values (e.g. Table 3A.1.10 of IPCC GPG-LULUCF 2003)[13]
MEASUREMENT PROCEDURES	N/A
COMMENTS	BEFs in IPCC literature and national forest inventories are usually applicable to closed canopy forests. If applied to individual trees growing in open field, it is recommended that the selected BEF_2 be increased by 30%

DATA / PARAMETER	$BEF_{1,j}$
DATA UNIT	Dimensionless
USED IN EQUATIONS	4
DESCRIPTION	Biomass expansion factor for conversion of annual net increment (including bark) in stem biomass to total above-ground tree biomass increment for species j
SOURCE OF DATA	• Local sources of species or group of species-specific data;

[13] Although the BEFs in Table 3A.1.10 apply to biomass, the dimensionless factors can be equally applied for wood volume expansions.

	• National sources of species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species • IPCC default values (e.g. Table 3A.1.10 of IPCC GPG-LULUCF 2003)[14]
MEASUREMENT PROCEDURES	N/A
COMMENTS	BEFs in IPCC literature and national inventory data are usually applicable to closed canopy forest. If applied to individual trees growing in open field it is recommended that the selected BEF be increased by a further 30%

DATA / PARAMETER	$B_{LOSS_BSL,j,t}$
DATA UNIT	MT d.m.
USED IN EQUATIONS	4
DESCRIPTION	Loss of tree biomass of species **j** in year **t**
SOURCE OF DATA	Existing data from the records relating to the project area. The source data could be the basis for estimating the rate at which pre-project activities (such as collection fuelwood or fodder, selection harvesting, mortality of trees, etc.) are reducing biomass stocks in existing live trees
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	BD_{TREE_BSL}
DATA UNIT	MT d.m. ha^{-1}

[14] Although the BEFs in Table 3A.1.10 apply to biomass, the dimensionless factors can be equally applied for wood volume expansions.

USED IN EQUATIONS	6
DESCRIPTION	Tree biomass density per unit area of the project area (obtained from published literature)
SOURCE OF DATA	Published data may relate to the project area or to another area similar to the project area. If published data is in terms of volume and not in terms of biomass, or the biomass data does not include the below-ground biomass, then transparent and verifiable method using suitable parameters may be used for calculating the tree biomass per unit area from the available data
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	B_{FOREST}
DATA UNIT	MT d.m. ha^{-1}
USED IN EQUATIONS	7
DESCRIPTION	Default above-ground biomass content in forest in the region/country where the A/R ACR project activity is located
SOURCE OF DATA	The source of data shall be selected, in order of preference, from the following: • Regional/national inventories e.g. national forest inventory, national GHG inventory; • Inventory from neighbouring countries with similar conditions; • Globally available data applicable to the project site or to the region/country where the site is located (e.g. latest data from FAO); • IPCC default values from Table 3A.1.4 of IPCC GPG-LULUCF 2003
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_j
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	19, 20
DESCRIPTION	Carbon fraction of tree biomass for species or group of species j
SOURCE OF DATA	The source of data, in order of preference, shall be the following: • National level species or group of species-specific data (e.g. from national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data (e.g. IPCC GPG-LULUCF 2003); • The IPCC default value of 0.5 MT C MT^{-1} d.m.
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_{DW}
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	25, 26
DESCRIPTION	Carbon fraction of dry matter in dead wood biomass
SOURCE OF DATA	Default value 0.5 MT C MT^{-1} d.m. shall be used
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_{LI}
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	30

DESCRIPTION	Carbon fraction of dry matter in litter biomass
SOURCE OF DATA	Default value 0.37 MT C MT^{-1} d.m. shall be used
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_{TREE_BSL}
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	2
DESCRIPTION	Carbon fraction of dry matter for tree biomass in baseline
SOURCE OF DATA	Default value 0.50 MT C MT^{-1} d.m. may be used
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	D_j
DATA UNIT	MT d.m. m^{-3}
USED IN EQUATIONS	4, 19
DESCRIPTION	Basic wood density for species or group of species j
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • National and species or group of species-specific data (e.g. from national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available species or group of species-specific data (e.g. Table 3A.1.9 IPCC GPG-LULUCF 2003)
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	$D_{DW,ds}$
DATA UNIT	MT d.m. m^{-3}
USED IN EQUATIONS	28
DESCRIPTION	Basic wood density of dead wood in the density state: 1 (sound), 2 (intermediate) or 3 (rotten)
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: I. National and species-specific or group of species-specific data (e.g. from national GHG inventory); II. Species-specific or group of species-specific data from neighbouring countries with similar conditions. Sometimes (II) might be preferable to (I); III. Globally species-specific or group of species-specific (e.g. IPCC GPG-LULUCF 2003)
MEASUREMENT PROCEDURES	Project specific determination of the density is allowed

DATA / PARAMETER	$f_j(DBH, H)$
DATA UNIT	MT d.m. $tree^{-1}$
USED IN EQUATIONS	20
DESCRIPTION	Allometric function for species or group of species j linking tree diameter (diameter at breast height or other diameter), and possibly tree height (H), to above-ground biomass of living trees
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • Existing local and species or group of species-specific data; • National and species or group of species-specific data (e.g. national forest inventory or national GHG inventory);

	• Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species (e.g. Tables 4.A.1–4.A.3 of IPCC GPG-LULUCF 2003)
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	$I_{V,j,t}$
DATA UNIT	$m^3\ ha^{-1}\ yr^{-1}$
USED IN EQUATIONS	4
DESCRIPTION	Average annual increment in stem volume of species j, in year t
SOURCE OF DATA	The source of data, in order of preference, shall be the following: • Existing local and species or group of species-specific tree growth data or local volume tables; • National and species or group of species-specific tree growth data or standard volume tables (e.g. from national forest inventory or national GHG inventory); • Species or group of species-specific tree growth data or volume tables from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species
MEASUREMENT PROCEDURES	N/A
COMMENTS	$I_{V,j,t}$ is estimated as the "current annual increment – CAI". The "mean annual increment" – often abbreviated as MAI in the forestry inventories– can only be used if its use leads to conservative estimates. The values read from tables if expressed on the per unit of area basis will usually apply to fully stocked forest. Thus, they should be corrected to be applicable in the baseline conditions, e.g. by multiplication by the fraction of tree crown cover or fraction of number of stems in the baseline stratum of interest (other ways of correction may be proposed by project proponents)

DATA / PARAMETER	$OF_{i,t}$, $SLF_{i,t}$, $WW_{i,t}$
DATA UNIT	MT C
USED IN EQUATIONS	38-41
DESCRIPTION	$OF_{i,t}$ = Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere between 5 and 100 years after production; $SLF_{i,t}$ = Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere within 5 years of production; $WW_{i,t}$ = Fraction of biomass extracted from stratum i up to year t effectively emitted to the atmosphere during production.
SOURCE OF DATA	The source of the data is the published paper of Winjum et al. 1998: Winjum, J.K., Brown, S. and Schlamadinger, B. 1998. Forest harvests and wood products: sources and sinks of atmospheric carbon dioxide. Forest Science 44: 272-284
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	R_j
DATA UNIT	Dimensionless
USED IN EQUATIONS	19, 20
DESCRIPTION	Root-shoot ratio for species or group of species j
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • Existing local and species or group of species-specific data; • National and species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions;

	● Globally available data applicable to species or group of species growing under similar conditions or similar forest type. If none of the above sources are available, then the value of R_j may be calculated as B/A where $B = \exp[-1.085 + 0.9256 \times \ln(A)]$, where A is above-ground biomass (t d.m. ha^{-1}) and B is below-ground biomass (t d.m. ha^{-1}) [Source: Table 4.A.4 of IPCC GPG-LULUCF 2003]
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	R_{1j}
DATA UNIT	kg d.m.yr^{-1} (kg d.m.yr^{-1})$^{-1}$
USED IN EQUATIONS	4
DESCRIPTION	Root-shoot ratio appropriate for biomass increment for species j
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: I. National and species-specific or group of species-specific (e.g. from national GHG inventory); II. Species-specific or group of species-specific from neighbouring countries with similar conditions. Sometimes (II) might be preferable to (I); III. Species-specific or group of species-specific from global studies
MEASUREMENT PROCEDURES	N/A
COMMENTS	If none of the above sources are available, then the value of R_{1j} may be calculated as B/A where $B = \exp[-1.085 + 0.9256 \times \ln(A)]$, where A is above-ground biomass (t d.m. ha^{-1}) and B is below-ground biomass (t d.m. ha^{-1}) [Source: Table 4.A.4 of IPCC GPG-LULUCF 2003]

DATA / PARAMETER	R_{TREE_BSL}
DATA UNIT	Dimensionless

USED IN EQUATIONS	7
DESCRIPTION	Root-shoot ratio for the trees in the baseline
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • Existing local and species or group of species-specific data; • National and species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species growing under similar conditions or similar forest type. If none of the above sources are available, then the value of R_{TREE_BSL} may be calculated as B/A where $B = \exp[-1.085 + 0.9256 \times \ln(A)]$, where **A** is above-ground biomass (t d.m. ha^{-1}) and B is below-ground biomass (t d.m. ha^{-1}) [Source: Table 4.A.4 of IPCC GPG-LULUCF 2003]
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	$V_{TREE,j,p,i}$
DATA UNIT	m^3
USED IN EQUATIONS	19
DESCRIPTION	Stem volume of trees of species or group of species **j** in plot **p** in stratum **i**
SOURCE OF DATA	The source of data, in order of preference, shall be the following: • Existing local and species or group of species-specific tree growth data or local volume tables; • National and species or group of species-specific tree growth data or standard volume tables (e.g. from national forest inventory or national GHG inventory);

	• Species or group of species-specific tree growth data or volume tables from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species
MEASUREMENT PROCEDURES	N/A
COMMENTS	In case of ex ante estimation, it would not be possible to measure diameter of trees to be used in volume tables. In such cases, species-specific or group of species-specific age-diameter curves from local/national sources may be used to estimate the diameter at a given point of time. Age of trees in baseline may be estimated from historical records, participatory appraisal, or tree dendrometry methods. If such age-diameter curves are not available then average growing stock values from Table 3A.1.4 of IPCC GPG-LULUCF 2003 may be multiplied by the fractional value of estimated crown cover of trees. For example, if crown cover of trees is estimated as 10% and the project is located in Cameroon (growing stock volume of 135 m3/ha), then the stem volume of trees may be estimated as 0.10 × 135 = 13.50 m^3/ha

DATA / PARAMETER	1605b
DATA UNIT	Dimensionless
USED IN EQUATIONS	35
DESCRIPTION	Proportion of wood products still "in use" 100 years after production
SOURCE OF DATA	The source is the Forestry Appendix of US Department of Energy's Technical Guidelines for The Voluntary Reporting of Greenhouse Gas Program (Section 1605b): http://www.eia.doe.gov/oiaf/1605/Forestryappendix[1].pdf; also available as a US Forest Service General Technical Report at: http://www.fs.fed.us/ne/durham/4104/papers/ne_gtr343.pdf
MEASUREMENT PROCEDURES	N/A

3 MONITORING METHODOLOGY

All data collected as part of monitoring should be archived electronically and be kept at least for two years after the end of the last crediting period. One hundred percent of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted according to relevant standards. In addition, the monitoring provisions in the tools referred to in this methodology apply.

3.1 MONITORING OF PROJECT IMPLEMENTATION

Information shall be provided, and recorded in the GHG Project Plan, to establish that:

I. The geographic coordinates of the project boundary (and any stratification inside the boundary) are established, recorded and archived;
II. Commonly accepted principles of forest inventory and management in the host country are implemented. In absence of these, standard operating procedures (SOPs) and quality control/quality assurance (QA/QC) procedures for inventory operations, including field data collection and data management, shall be identified, recorded and applied. Use or adaptation of SOPs available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended;
III. The forest planting and management plan, together with a record of the plan as actually implemented during the project, shall be available for validation and/or verification.

3.2 SAMPLING DESIGN AND STRATIFICATION

Stratification of the project area into relatively homogeneous units can either increase the measuring precision without increasing the cost unduly, or reduce the cost without reducing measuring precision because of the lower variance within each homogeneous unit. PPs should present in the GHG Project Plan an ex ante stratification of the project area or justify the lack of it. The number and boundaries of the strata defined ex ante may change during the crediting period (ex post).

3.2.1 Updating of Strata

The ex post stratification shall be updated because of the following reasons:

- Unexpected disturbances occurring during the crediting period (e.g. due to fire, pests or disease outbreaks), affecting differently various parts of an originally homogeneous stratum;

- Forest management activities (cleaning, planting, thinning, harvesting, coppicing, re-replanting) that are implemented in a way that affects the existing stratification.

Established strata may be merged if reasons for their establishing have disappeared.

3.2.2 Precision Requirements

The targeted precision level for biomass estimation shall be ±10% of the mean at a 90% confidence level. Given the correlation between biomass and volume, assessing the precision level with a confidence interval for cubic foot volume is sufficient. PPs may use the latest version of the approved tool for "Calculation of the number of sample plots for measurements within A/R CDM project activities" to determine the sample size and allocation of sample plots among strata.

3.3 REGENERATION MONITORING AREAS

To ensure that the natural (without planting) regeneration rates assumed in the baseline scenario remain valid over the Crediting Period, the Project Proponent shall establish a Regeneration Monitoring Area for each of the strata in the project. Each Regeneration Monitoring Area must be at least 1/4 hectare in size and must be designated outside the project boundary in an area similar to the project area in soil type, slope, aspect, and distance to seed sources. Regeneration Monitoring Areas should be near the project area, but it is suggested they be located far enough away to avoid regeneration due to seeds from the trees planted in the project area.

Each Regeneration Monitoring Area must be examined close to the project start date to determine initial regeneration values. Each Regeneration Monitoring Area must then be re-assessed at intervals not to exceed ten (10) years for the duration of the Crediting Period.

At each re-assessment, regeneration (number of seedlings per hectare) in the Regeneration Monitoring Areas shall be compared to the regeneration assumptions used for the baseline to determine whether the number of seedlings per hectare varies significantly from assumptions. If the observed number of seedlings per hectare exceeds the baseline estimate by more than 10% and by more than 10 trees per hectare, the baseline scenario (including the baseline scenario simulated by FVS, if used) must be modified to better reflect the observed values.

Note that although the required reassessment of natural regeneration based on Regeneration Monitoring Areas may require revision of the baseline regeneration assumptions, this only applies to the current and future calculation of net emission reductions. Baseline revisions will not be applied retroactively to credits already verified and issued in earlier years.

3.4 DATA AND PARAMETERS MONITORED

The following data and parameters should be monitored during the project activity. When applying all relevant equations provided in this methodology for the ex ante calculation of net anthropogenic GHG removals by sinks, PPs shall provide transparent estimations for the parameters that are monitored during the crediting period. These estimates shall be based on measured or existing published data where possible and PPs should retain a conservative approach: That is, if different values for a parameter are equally plausible, a value that does not lead to over-estimation of net anthropogenic GHG removals by sinks should be selected.

DATA / PARAMETER	A_i
DATA UNIT	ha
USED IN EQUATIONS	21, 28
DESCRIPTION	Area of tree biomass stratum i
SOURCE OF DATA	Monitoring of strata and stand boundaries shall be done preferably using a Geographical Information System (GIS), which allows for integrating data from different sources (including GPS coordinates and Remote Sensing data)
MEASUREMENT PROCEDURES	See section 3.1 (II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1 (II)

DATA / PARAMETER	$A_{BSL,j}$
DATA UNIT	ha
USED IN EQUATIONS	4
DESCRIPTION	Area under trees of species j in baseline

SOURCE OF DATA	GPS coordinates and/or remote sensing data
MEASUREMENT PROCEDURES	See section 3.1 (II)

DATA / PARAMETER	$a_{j,p}$
DATA UNIT	m^2
USED IN EQUATIONS	29
DESCRIPTION	Area of sampling frame for plot **p** in stratum **i**
SOURCE OF DATA	Simple measurement or manufacturer's data
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)
COMMENTS	Once selected, the size of the sampling frame shall be fixed until the end of the last crediting period

DATA / PARAMETER	$A_{p,i}$
DATA UNIT	ha
USED IN EQUATIONS	21
DESCRIPTION	Total area of all sample plots in stratum **i**
SOURCE OF DATA	Field measurement
MEASUREMENT PROCEDURES	See section 3.1(II)

MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	$B_{LI_WET,i,p}$
DATA UNIT	kg
USED IN EQUATIONS	29
DESCRIPTION	Wet weight (field) of the litter in plot **p** of stratum **i**
SOURCE OF DATA	Field measurements in sample plots
MEASUREMENT PROCEDURES	**STEP 1** Litter shall be sampled using a sampling frame. The frame is placed at four locations within the sample plot. **STEP 2** At each location, all litter (leaves, fruits, small wood, etc.) falling inside the frame shall be collected and the litter from four locations is mixed to get a representative sample for measuring the wet weight of the biomass
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	$D_{n,i,t}$
DATA UNIT	cm
USED IN EQUATIONS	27
DESCRIPTION	Diameter of piece **n** of dead wood along the transect in stratum **i**, at time **t**
SOURCE OF DATA	Field measurements in sample plots

MEASUREMENT PROCEDURES	Lying dead wood should be sampled using the line intersect method (Harmon and Sexton, 1996).[15] Two 50-m lines bisecting each plot are established, and the diameters of the lying dead wood (≥5 cm diameter) intersecting the lines are measured
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	DBH
DATA UNIT	inch/cm or any unit of length used in the model or data source used
USED IN EQUATIONS	Implicitly used in equation 19, 20
DESCRIPTION	Usually the diameter at breast height of the tree; but it could be any other diameter or dimensional measurement used in the model or data source used, e.g. basal diameter, root-collar diameter, basal area, etc.
SOURCE OF DATA	Field measurements in sample plots. For ex ante estimations, DBH values should be estimated using a growth curve, a growth model, or a yield table that gives the expected tree dimensions as a function of tree age
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	H

[15] Harmon, M. E. and J. Sexton. (1996) Guidelines for Measurements of Woody Detritus in Forest Ecosystems. US LTER Publication No. 20. US LTER Network Office, University of Washington, Seattle, WA, USA.

DATA UNIT	m or any other unit of length
USED IN EQUATIONS	Implicitly used in equation 19, 20
DESCRIPTION	Height of tree
SOURCE OF DATA	Field measurements in sample plots. For ex ante estimations, H values should be estimated using a growth curve, a growth model, or a yield table that gives the expected tree dimensions as a function of tree age
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)
COMMENTS	Models used may be based on units of length other than meter (e.g. feet), in which case the appropriate unit of length only should be used

DATA / PARAMETER	L
DATA UNIT	m
USED IN EQUATIONS	27
DESCRIPTION	Length of the transect to determine volume of lying dead wood
SOURCE OF DATA	Field measurements
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	MP_{LI}
DATA UNIT	Dimensionless
USED IN EQUATIONS	29
DESCRIPTION	Dry-to-wet weight ratio of the litter (dry weight/wet weight)
SOURCE OF DATA	Laboratory measurement of field samples
MEASUREMENT PROCEDURES	Litter samples shall be collected and well mixed into one composite sample at the same time of year in order to account for natural and anthropogenic influences on the litter accumulation and to eliminate seasonal effects. A subsample from the composite sample of litter is taken, oven dried and weighed to determine the dry weight
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	N
DATA UNIT	Dimensionless
USED IN EQUATIONS	27
DESCRIPTION	Total number of wood pieces intersecting the transect
SOURCE OF DATA	Field measurements
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	T
DATA UNIT	Year
USED IN EQUATIONS	17, 23, 30
DESCRIPTION	Time period elapsed between two successive estimations of carbon stock in a carbon pool
SOURCE OF DATA	Recorded time
MEASUREMENT PROCEDURES	N/A
COMMENTS	If the two successive estimations of carbon stock in a carbon pool are carried out at different points of time in year t_2 and t_1, (e.g. in the month of April in year t_1 and in the month of September in year t_2), then a fractional value shall be assigned to T

3.5 CONSERVATIVE APPROACH AND UNCERTAINTIES

While applying this methodology, PPs shall ensure that "Guidelines on conservative choice and application of default data in estimation of the net anthropogenic GHG removals by sinks"[16] are followed for addressing uncertainty.

In choosing key parameters or making important assumptions based on information that is not specific to the project circumstances, such as in use of default data, PPs should select values that will lead to an accurate estimation of net GHG removals by sinks, taking into account uncertainties. If uncertainty is significant, PPs should choose data such that it tends to under-estimate, rather than over-estimate, net GHG removals by sinks.

[16] See http://cdm.unfccc.int/Reference/Guidclarif/ar/methAR_guid26.pdf.

4 ESTIMATES USING THE FOREST VEGETATION SIMULATOR (FVS)

Some sections of this methodology refer to the Forest Vegetation Simulator (FVS) as a tool to estimate carbon stock changes. FVS is the U.S. Forest Service's (USFS) national forest growth model. The FVS software package is free and available on the internet (http://www.fs.fed.us/fmsc/fvs/).

When following this methodology, the version of the FVS software used shall always be at least as recent as the version available at the project start date. If a model user would like to update their FVS software mid-project, this is acceptable as long as consistency is maintained; in this case both the baseline and project calculations must be done with the updated software.

Care and attention to detail must be exercised when using FVS with this methodology. To ensure the best estimates possible, Project Proponents shall follow these guidelines:

- FVS may only be used for projects located within the United States, and only using variants maintained by the FVS staff. Variants for outside the U.S. are available, but are not maintained by the USFS. As a result, USFS cannot verify the biomass and carbon calculation methods used in those variants.
- Select the appropriate geographic variant of FVS. A map and associated GIS shapefiles depicting the suggested FVS variants are available on the FVS website (http://www.fs.fed.us/fmsc/fvs/whatis/index.shtml). If an FVS variant other than the one suggested by the variant map is used, the reasoning behind this substitution must be documented.
- Use current inventory data for model projections. Inventory data older than 10 years may not be used to estimate current carbon stocks.
- Provide as much information with the input data set as possible. As an example, FVS variants often use variables such as slope, aspect, elevation, and a measure of site quality (e.g., site index, habitat type, or plant association) to estimate forest growth over time. Provide this information wherever possible to help ensure accurate predictions. The information relevant to the selected variant is described in the variant overview document available from the FVS website. It is highly recommended that site index or other measures of site quality used by the variant are included as input in FVS simulations. Also, measured growth data (e.g., large tree diameter growth and small tree height growth) can be used to calibrate the growth estimates built into each variant. Including growth sample measurements with simulations will improve model results. Tree records for species not modelled within a specific variant are mapped within FVS to a similar species. If model users change the species designation on input (and hence create their own personally designated species mapping), the reasoning behind this substitution must be documented.

- Be aware of how regeneration is being handled with the variant. Some variants have a full-regeneration model, where regeneration is predicted and added to the model over time. Other variants have a partial-regeneration model that adds in sprouts after fire or harvest, but does not automatically include any other types of regeneration. Understand what the model is doing so you can adjust or add additional regeneration as needed. In addition, the assumptions about baseline regeneration used in FVS must be evaluated through the periodic assessment of Regeneration Monitoring Areas as described in section 3.3.
- Describe which biomass calculation method was selected for the simulations. The FFE method (the default) is the preferred method as it uses more localized volume/biomass equations for each variant and uses species-specific lbs/cubic foot conversion factors. A full description can be found in the FVS Fire and Fuels Extension Guide[18]. The Jenkins' equations, a national set of equations that predict biomass based on species group and dbh, may only be used if it can be demonstrated to the validation/verification body that these are more accurate than the FFE method for the project area.
- Identical settings and model assumptions shall be used to compare project conditions or multiple projects. As an example, make sure the units selected for the carbon calculations are metric tons of carbon/hectare for all simulations. If biomass is calculated using the FFE method, then this method shall be used for all conditions and projects. Similarly, if regeneration has been adjusted, then appropriate adjustments shall be made for all conditions and projects.
- Provide the FVS keyword file (*.key), FVS main output file (*.out) as well as the input data files for review by ACR and/or the validation/verification body.

For additional information about FVS and its carbon calculations, see the Essential FVS Guide[17] and the FVS Fire and Fuels Extension Guide[18]. Variant overviews that describe each individual geographic variant are also available on the FVS website.

[17] Dixon, Gary E. comp. 2002. Essential FVS: A user's guide to the Forest Vegetation Simulator. Internal Rep. Fort Collins, CO: U. S. Department of Agriculture, Forest Service, Forest Management Service Center. 226p. (http://www.fs.fed.us/fmsc/ftp/fvs/docs/gtr/EssentialFVS.pdf)

[18] Rebain, Stephanie A. comp. 2010. The Fire and Fuels Extension to the Forest Vegetation Simulator: Updated Model Documentation. Internal Rep. Fort Collins, CO: U. S. Department of Agriculture, Forest Service, Forest Management Service Center. 396p. (http://www.fs.fed.us/fmsc/ftp/fvs/docs/gtr/FFEguide.pdf).

5 REFERENCES AND OTHER INFORMATION

All references are quoted in footnotes.

5.1 HISTORY OF THE DOCUMENT

VERSION	DATE	NATURE OF REVISION(S)
1.2	31 May 2017	An applicability condition was changed allowing projects to be implemented on wetlands (with conditions).
1.1	12 June 2013	Modification, adding Forest Vegetation Simulator (FVS) as an approved tool to estimate carbon stock changes, following approval by ACR AFOLU Technical Committee.
1.0	08 March 2011	Initial adoption under ACR, following approval by ACR AFOLU Technical Committee.
AR-ACM0001 v05.0.0	EB56, Annex 12 17 September 2010	Adoption by the CDM Executive Board of version 5.0.0 of methodology AR-ACM0001, “Afforestation and reforestation of degraded land,” on which the ACR methodology is based.

DEFINITIONS

Afforestation/ Reforestation (A/R)	Activities to increase carbon stocks by establishing, increasing and restoring vegetative cover through the planting, sowing or human-assisted natural regeneration of woody vegetation. A/R activities must target the eventual establishment of "forest" per the applicable definition. In general, the term afforestation is applied to activities to establish forest on lands that have been in another land use for some relatively long period, while reforestation is applied to activities to reestablish forest on lands that were in forest cover relatively recently. ACR does not make a specific distinction between afforestation and reforestation, since both are eligible
Baseline	Most likely management scenario in the absence of the Project
Basal Area	The area of a given section of land that is occupied by the cross-section of tree trunks and stems at the base.
Buffer Pool	ACR risk mitigation mechanism whereby the Project Proponent contributes an adequate number of ERTs to a buffer pool held by ACR to replace unforeseen losses in carbon stocks. The buffer contribution is a percentage of the project's reported offsets, determined through a project-specific assessment of the risk of reversal. Buffer contributions may come from the project itself, or be made using ERTs of any other type and vintage.
Carbon Pool	A reservoir of carbon that has the potential to accumulate or lose carbon over time. Common forest carbon pools are aboveground biomass, belowground biomass, litter, dead wood, soil organic carbon, and wood products.
Carbon Stocks	Carbon stocks represent the measured, estimated or modeled quantity of carbon held in a particular carbon pool. Quantifying GHG emissions and removals for terrestrial carbon offset projects involves estimating, for the baseline and project scenarios, changes over time in carbon stocks in relevant pools
Clean Development Mechanism (CDM)	The CDM allows GHG emission reduction and removal projects in developing countries to earn certified emission reduction (CER) credits, each equivalent to one metric ton of CO2, which can be sold and used by industrialized countries to a meet a part of their emission reduction targets under the Kyoto Protocol. The CDM is intended to stimulate sustainable

	development and emission reductions, while giving industrialized countries flexibility in how they meet their emission reduction targets.
Crediting Period	The period of time in which the baseline is considered to be valid and project activities are eligible to generate ERTs
Crown Cover	The proportion of a stand covered by the crowns of live trees
Degraded lands	Degraded land is land that has lost some degree of its natural productivity due to human-caused processes
Ex-ante	"Before the event" or predicted response of Project activity
Ex-post	"After the event" or measured response of Project activity
Leakage	Leakage refers to a decrease in sequestration or increase in emissions outside project boundaries as a result of project implementation. Leakage may be caused by shifting of the activities of people present in the project area, or by market effects whereby emission reductions are countered by emissions created by shifts in supply of and demand for the products and services affected by the project.
Natural Regeneration	The ability of an environment, most often a forest, to regenerate itself without external intervention following a disturbance
Offset	Reduction in emissions of GHG made in order to compensate for or to offset an emission made elsewhere.
Project Proponent	An individual or entity that undertakes, develops, and/or owns a project. This may include the project investor, designer, and/or owner of the lands/facilities on which project activities are conducted. The Project Proponent and landowner/facility owner may be different entities. The Project Proponent is the ACR account holder.
Stand Density Index	A measure of the stocking of a stand of trees based on the number of trees per unit area and diameter at breast height of the tree of average basal area, also known as the quadratic mean diameter.
Stratification	A standard statistical procedure to decrease overall variability of carbon stock estimates by grouping data taken from environments with similar characteristics (e.g., vegetation type, age class, hydrology, elevation)

American Carbon Registry
AT WINROCK INTERNATIONAL

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

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ACKNOWLEDGEMENTS

Financial support for the revision and update of this methodology from version 1.0 to 2.0 was provided by the Conservation Innovation Grants program at USDA's Natural Resources Conservation Service (awarded to Ducks Unlimited in 2015). Technical support for Version 2.0 was provided by: Tyler Lark (University of Wisconsin), Dr. Claire Runge (U.C. Santa Barbara), Dr. Joe Fargione (The Nature Conservancy), and Jason Roudebush and Billy Gascoigne (Ducks Unlimited). Version 1.0 of the methodology was written by: Randall Dell (Ducks Unlimited), Drs. Marissa Aherling and Joe Fargione (The Nature Conservancy), Peter Wiseburg and David Diaz (The Climate Trust), Ashley Rood (Environmental Defense Fund), and Drs. Steven DeGryze and Benktesh D. Sharma (Terra Global Capital).

This methodology was developed by Ducks Unlimited, The Nature Conservancy and the American Carbon Registry.

Ducks Unlimited

The Nature Conservancy

American Carbon Registry

Financial support for the development of this methodology was provided by:

U.S. Department of Agriculture
Natural Resources
Conservation Service

ACRONYMS

AC	Avoided Conversion
ACoGS	Avoided Conversion of Grasslands and Shrublands
ACR	American Carbon Registry
AFOLU	Agriculture, Forestry and Other Land Use
APEX	Agricultural Policy Environmental eXtender Model
CO_2e	Carbon dioxide equivalent
CH_4	Methane
CDM A/R	Clean Development Mechanism Afforestation/Reforestation
CRP	Conservation Reserve Program
DAYCENT	Daily Time Step Version of the CENTURY Biogeochemical Model
d.u.	Dimensionless unit
EF	Emission Factor
EPA	Environmental Protection Agency
ERS	Economic Research Service
ERT	Emission Reduction Ton
GHG	Greenhouse Gas
IA	Identified Agent
IPCC	Intergovernmental Panel on Climate Change
LU/LC	Land Use/Land Cover
LCA	Land Conservation Agreement
LCC	Land Capability Class

MLRA	Major Land Resource Areas
NH_3	Ammonia
N_2O	Nitrous Oxide
NLCD	National Cropland Data Layer
NO_X	Nitrogen Oxides
PDA	Programmatic Development Approach
REDD	Reduced Emissions from Deforestation and Degradation
SOC	Soil Organic Carbon
SSR	Sources, Sinks and Reservoir
UA	Unidentified Agent
VVB	Validation/Verification Body

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1 BACKGROUND AND APPLICABILITY

1.1 SUMMARY DESCRIPTION OF METHODOLOGY

This methodology estimates the emissions avoided by preventing the conversion of Grasslands and Shrublands to annual crop production.[1] Conversion of Grassland and Shrubland to uses other than annual Cropland is not an eligible activity under this methodology. Conversion to orchards and vineyards is not an eligible activity under this methodology. Grassland and shrubland soils are significant reservoirs of organic carbon that will, if left uncultivated, continue to store this carbon belowground. Grassland and shrubland ecosystems may also support greater plant biomass than annual Cropland, especially belowground. In addition to the avoided cultivation and oxidation of soil organic carbon, several crop production practices with GHG implications, such as fertilizer applications, may also be avoided through the project activity. Livestock, primarily cattle, are anticipated to be common in the project scenario and their associated emissions from enteric fermentation and manure deposition are accounted.

This methodology accounts for two Avoided Conversion baseline scenarios: 1) where the conversion agent is identified and 2) where the conversion agent is unidentified. Projects that can identify the conversion agent are required to demonstrate proof of intent to convert by the identified agent. Where the specific conversion agent cannot be identified but a class of likely agents can, the Unidentified Agent baseline approach is used to determine the probability of conversion. This approach is based on historical rates of conversion of existing grasslands and shrublands within a county, in addition to the various land capability classes suitable for agriculture at the field level.

The removal of project lands from the supply of potential Cropland is expected to create leakage effects, all in the form of market leakage.[2] A default market leakage estimate is offered to account for these effects. Standardized values for leakage and baseline determination are specific to the United States.

[1] Eligible project types may include, but are not limited to, the avoided conversion of native rangeland, and grasslands established under the Conservation Reserve Program (United States) that have been in grassland cover for a minimum of 10 years.

[2] Leakage and market leakage are defined in the ACR Standard. Leakage is a decrease in sequestration or increase in emissions outside project boundaries resulting from project implementation. Leakage may

Unless specified otherwise in this document, projects are subject to all requirements and specifications in the most current version the American Carbon Registry Standard. Definitions specific to this methodology can be found at the end of the document.

1.2 APPLICABILITY CONDITIONS

In addition to satisfying the latest ACR program requirements, project activities must satisfy the following conditions for this methodology to apply:

- All Participant Fields avoid the complete conversion[3] of Grasslands or Shrublands to annual Cropland. Conversion of Grassland and Shrubland to uses other than annual Cropland is not an eligible activity under this methodology.
- All Participant Fields in the Project Area are currently Grassland or Shrubland, have qualified as Grassland or Shrubland for at least 10 years prior to the Start Date[4], will remain as Grassland or Shrubland throughout the Project Term, and are legally able to be converted and would be converted to Cropland in the absence of the project activity.
- All Participant Fields enrolled in the Project Area must be subject to a qualified Land Conservation Agreement (LCA) entered into by the Project Participant prohibiting the conversion of the land from Grassland or Shrubland for the duration of the minimum Project Term or longer. The area bound by the LCA does not have to match the Project Area nor Participant Field enrolled; however, the entire area of the Participant Field must be included in the area covered by the LCA. The LCA must also explicitly prohibit grassland conversion to another land use—often referred to as a "sod-buster" clause—such that avoidable reversals are sufficiently precluded as long as the LCA is enforced.[5] If the easement allows for alternative land use other than grassland preservation, such as building envelopes, gravel sites, road development, etc., those areas must be delineated and removed from the eligible portion of the Participant Field. The LCA must be recorded on the deed of the property encompassing all Participant Fields to ensure transferability among ownership.

be caused by shifting of the activities present in the project area or by market effects whereby emission reductions are countered by emissions created by shifts in supply of and demand for the products and services affected by the project. See Section 6.3 for discussion of leakage as pertains to this project type.

[3] The complete removal of initial vegetation community through complete tillage, chemical treatment, fire, or combinations thereof which are followed by seeding of an annual crop.

[4] In the case of aggregated projects, Participant Fields must have qualified as Grassland or Shrubland for at least 10 years prior to the date the Project Participants agreed to enroll that field into the aggregate.

[5] ERTs will not be issued for any period of non-conformance with the LCA.

- In the case of an unidentified agent of conversion, the Project Area is located entirely in a county or counties listed in Appendix B.[6] In the case of an identified agent of conversion, written offers to lease or buy property must specify cropland as the intended/highest and best use, including reference to available water rights and infrastructure if irrigation is required; in the absence of written offers to lease or buy the property, landowner attestations or other documentation demonstrating threat to conversion must reference the highest and best use as cropland and other comparable conversion events in the region.
- Land may remain in use for livestock grazing and/or haying and be subject to prescribed burning or wildfires during the project scenario, so long as the provisions of the relevant qualified LCA are met. In the project scenario, detrimental overgrazing, overstocking, or overuse of prescribed fires leading to the progressive loss of vegetative cover shall not occur, allowing carbon pools to remain at a steady state. Supplemental management practices that increase carbon stocks in the project scenario are allowable but the resultant emissions avoided or removed are not eligible for crediting under this methodology.
- At least 50% of the project area is in Land Capability Class (LCC) I-IV and no more than 25% of the project area is LCC VII and VIII as assessed using the SSURGO non-irrigated lands database.
- When the landowner will hold title to the carbon rights, a statement of intent[7] to develop a carbon offset project is submitted to ACR no sooner than 12 months before and not longer than 12 months after the date that the qualified LCA is recorded.
- When the landowner will not hold title to the carbon rights, the date of any agreement (e.g. a carbon options agreement) transferring carbon rights from the landowner to the project developer must be enacted no sooner than 12 months before and not longer than 12 months after the date that the qualified LCA is recorded.
- The Project Area includes either one contiguous parcel, or multiple discrete parcels of land. If the Project Area consists of multiple discrete parcels, Project Proponents must demonstrate that each discrete parcel meets all applicability criteria of the methodology.
- Project Areas do not include Grasslands or Shrublands on organic soils or peatlands, nor include wetland acres within Grassland/Shrubland tracts. Additional information on how to appropriately identify and remove wetland acres and organic soils from GHG modeling and ERT calculation is provided in Section 2.1.2.
- An irrigated cropland scenario in the baseline and an irrigated project scenario are allowed. In the baseline scenario, a strong justification must be made for the likelihood of the irrigated cropland scenario that is ultimately subject to the verifier's professional judgement. The justification shall include, at a minimum, an assessment of irrigation water access—both legal and physical—to the Project Field(s) at the Project Start Date and evidence of ongoing irrigation practices on like parcels in the same county. Any biogeochemical models used for GHG

[6] Eligibility maps are updated at minimum every 5 years.

[7] Contact ACR administrator for a Statement of Intent template document or basic requirements.

modelling must have proven capabilities to account for GHG influences from specific irrigation practices.

- Where livestock are present in the project scenario, manure is not managed, stored, or dispersed in liquid form. Livestock are primarily forage fed and not managed in a confined area, e.g., feedlot. There are no restrictions on the application of synthetic or organic amendments, i.e. manure, in the baseline scenario.
- The Project Area is located in the United States.

1.3 PERIODIC REVIEWS AND REVISIONS

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes to project activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the methodology.

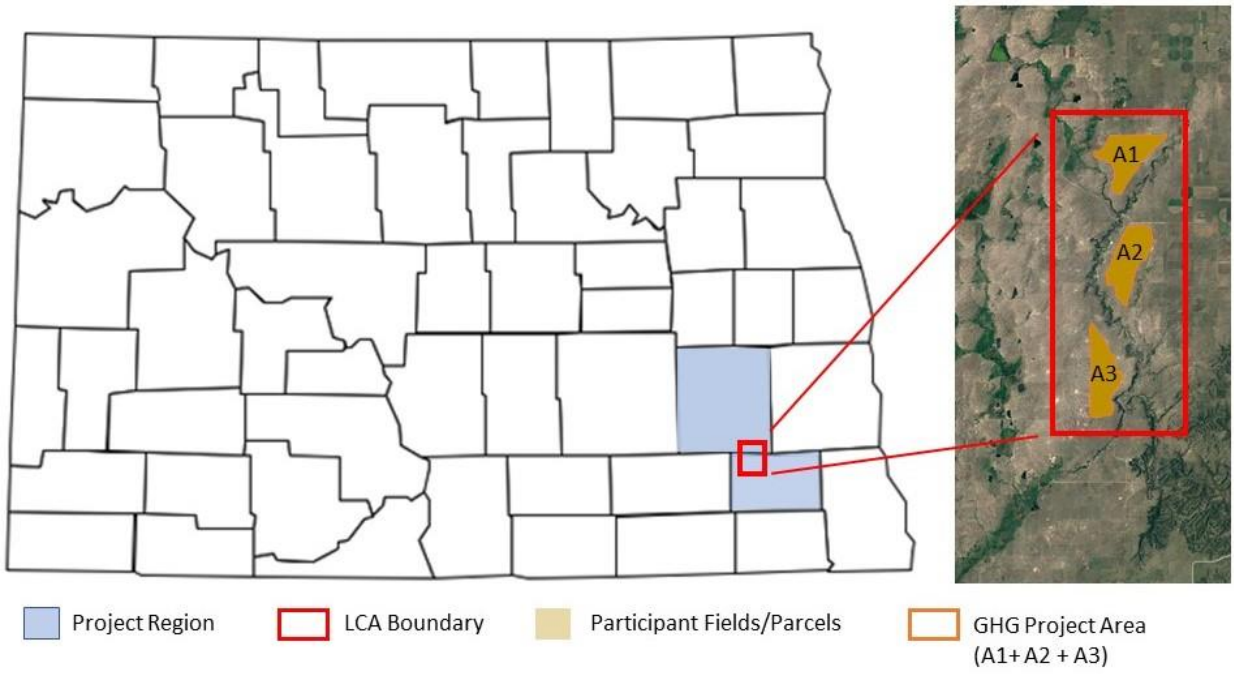
2 PROJECT BOUNDARIES

2.1 SPATIAL BOUNDARY

2.1.1 Field, Area, Region Boundary Terms

Figure 1: Spatial Boundaries

Three spatial boundaries are relevant to this methodology: Participant Fields, Project Area and Project Region.



Participant Fields are the discrete parcels where project activities are implemented, when referred to individually.

All Participant Fields must be covered in full by the qualified LCA and an agreement specifying ownership of any ERTs issued, if not specified in the qualified LCA. The GHG project area (e.g. area within Participant Field boundaries) may be smaller than but must be completely within the qualified LCA boundary.

The Project Area is the collection of Participant Fields. Other areas that may fall within relevant property boundaries but for which Grassland-Shrubland to Cropland conversion is not applicable (e.g., non-Grassland or Shrubland land cover, waterways, residences, etc.) are not included in the Project Area.

The Project Region may be an eco-region or geographic administrative unit of relatively homogenous economic conditions and governance at which baseline activities are occurring, e.g. a state, county, watershed, irrigation district, Major Land Resource Area, etc. The Project Region is the highest-level geographical boundary and is used in this methodology for demonstrating baseline conditions identification of baseline management practices and the quantification of greenhouse gas emission reductions and avoidance, i.e., to define the applicability of models and emission factors. The Project Region shall be further stratified to account for heterogeneity within the Project Region according to the procedures in Section 4 Stratification.

In situations where the Project Proponent (e.g., an aggregator or developer) is not the Project Participant (e.g., an owner of a Participant Field), the Project Proponent must demonstrate that a qualified LCA restricts the management of conversion activities (e.g. via a conservation easement) for the duration of the Project Term on each Participant Field. In situations where the Project Proponent does not take fee-title possession of the land, a conveyance of the associated GHG benefits of the avoided conversion activity from the Project Participant to the Project Proponent must demonstrate clear ownership of any ERTs generated by the project activity.

2.1.2 Recording the Project Area and Project Region

Spatially explicit data files (e.g. shapefiles for GIS) recording the following boundaries must be provided in the GHG Project Plan:

1. Project Region
2. Project Area
3. Participant Fields
4. Wetlands, building envelopes, cultivated areas, streams, roads, gravel pits or other areas not covered by a sod-buster clause and/or excluded from but within the Project boundary
5. LCA Boundary[8]
6. ERT ownership boundary (if different than 3 or 5)

[8] LCA boundary as recorded on the deed; if the LCA is not a recorded easement, adequate evidence, subject to verifier professional judgement, of due diligence in determining spatially accurate boundaries, must be provided.

See Section 7 Monitoring and Data Collection for additional details.

The Project Area is the collection of shape file polygons for all individual Participant Fields boundaries and is not necessarily contiguous.

The Project Region(s) must include the entirety of the Project Area within its (their) boundaries. The Project Region(s) may be comprised of non-contiguous areas so long as all Participant Fields are contained within a Project Region (i.e. the Project Area must be fully contained within the boundaries of the Project Region(s)) and all Participant Fields are within the qualified LCA boundary.

All required shapefiles shall be made available in the GHG Project Plan at time of validation. Wetland acreage delineation can often be subjective given the influence of yearly precipitation and associated variability. Where wetland acres are explicitly accounted in the language of the qualified LCA or otherwise legally encumbered, Project Proponents are to rely on the qualified LCA language or other legal protections for identifying total wetland acreage that is ineligible. Spatially explicit boundary shapefiles must be provided that delineate the total wetland acres in the qualified LCA. These shapefiles can then be either directly uploaded into a GHG accounting platform, or overlaid with the soils maps provided through NRCS's Web Soil Survey (http://web-soilsurvey.sc.egov.usda.gov/App/HomePage.htm) as required by biogeochemical models.

If wetland acres are not explicitly identified in the qualified LCA, Project Proponents must demonstrate at the time of project validation that no portion of the project area requires exclusion due to classification as a wetland, either permanent, emergent, seasonal or otherwise. Project Proponents must demonstrate to the satisfaction of the verifier that the project area is limited to the area that would reasonably be plowed under as part of conversion i.e. roads, building envelopes, infrastructure or wet areas are excluded.[9] These boundaries remain constant for the length of the project. The shapefiles delineating wetland acres must be provided and overlaid with the boundaries of the Participant Field(s).

2.2 GHG ASSESSMENT BOUNDARY

The GHG assessment boundary delineates the sources, sinks and reservoirs (SSRs) that must be included or excluded when quantifying the net changes in emissions associated with the avoided conversion of Grassland or Shrubland to Cropland.

All SSRs that are likely to result in a significant increase in GHG emissions or decreased carbon storage in the project scenario relative to the baseline must be accounted for, for each Participant Field.

[9] Verifiers may use SSURGO or other databases to inform the presence of soils that would be too wet or otherwise unsuitable for cultivation.

Specific carbon pools and GHG sources, including carbon pools and GHG sources that cause project and leakage emissions, may be deemed de minimis and do not have to be accounted for if in aggregate the omitted decrease in carbon stocks (in carbon pools) or increase in GHG emissions (from GHG sources) amounts to less than three percent of the total ex ante estimate of GHG benefit generated by the project.

2.2.1 Carbon Pools (Reservoirs)

Table 1: Carbon Pools

CARBON POOL	INCLUDED/ EXCLUDED	JUSTIFICATION
Tree biomass (above-ground, below ground)	Excluded	Tree biomass is conservatively excluded in both the baseline and project scenario.[10]
Above-ground non-tree, woody biomass	Optional	Likely to be a source of carbon loss in the baseline scenario and it is optional to include for both the baseline and project scenario. Where Project Proponents elect to include this pool in the project scenario, it must also be included in the baseline scenario.
Above-ground non-tree, non-woody biomass	Optional	Likely to be a source of carbon loss in the baseline scenario and it is optional to include for both the baseline and project scenario. Where Project Proponents elect to include this pool in the project scenario, it must also be included in the baseline scenario.
Litter	Excluded	Not a major pool in baseline or project scenarios.
Below-ground, non-tree biomass	Optional	Likely to be a significant source of carbon loss in baseline scenario. Projects may elect to account for below-ground biomass. Where Project Propo-

[10] All references to above-ground or below-ground biomass in this methodology are in reference to grassland, shrubland or cropland vegetation that does not meet the definition of a tree according to the U.S. Forest Service https://www.nrs.fs.fed.us/fia/data-tools/state-reports/glossary/default.asp

CARBON POOL	INCLUDED/ EXCLUDED	JUSTIFICATION
		nents elect to include this pool in the project scenario, it must also be included in the baseline scenario.
Soil organic carbon	Included	Major carbon pool subject to project activity.
Dead wood	Excluded	Not a major carbon pool in the baseline or project scenario.
Wood products	Excluded	Not a major carbon pool in the baseline or project scenario.

2.2.2 GHG Sources and Sinks

Table 2: Greenhouse Gas Sources

SOURCE	GAS	INCLUDED/ EXCLUDED	JUSTIFICATION
Soil Management	CO_2	Included	Accounted for in soil organic carbon pool.
	CH_4	Excluded	Not a significant gas for this source.
	N_2O	Included	Covers direct emissions from synthetic and organic N amendment sources. Indirect emissions from synthetic and organic N amendments are excluded.[11]
Fossil Fuel Combustion	CO_2	Optional	Baseline emissions from fossil fuel are likely larger than in the project scenario and may be conservatively excluded. Where Project Proponents elect to include this pool in the project scenario, it must also be included in the baseline scenario.

[11] This methodology assumes that baseline emissions of N_2O (direct or indirect) due to N amendments are always larger than project emissions of N_2O.

SOURCE	GAS	INCLUDED/ EXCLUDED	JUSTIFICATION
	CH_4	Excluded	Not a significant gas for this source.
	N_2O	Excluded	Not a significant gas for this source.
Biomass Burning	CO_2	Excluded	Accounted for in biomass pools.
	CH_4	Excluded	Not a significant gas for this source.
	N_2O	Excluded	Not a significant gas for this source.
Livestock Emissions	CO_2	Excluded	Not a significant gas for this source.
	CH_4	Optional	When livestock are present in the baseline and/or project scenario, this is a major source of emissions and must be included.
	N_2O	Excluded	Emissions of N_2O from livestock waste are captured under Soil Management emissions.

2.3 TEMPORAL BOUNDARY

The dates and time frames for the following project events must be defined in the GHG Project Plan:

- Project Start Date for each Participant Field enrolled
- Project Crediting Period start and end dates
- Date of submittal of Project listing with ACR (date when GHG Project Plan was initially submitted) for initial Participant Fields if a PDA Project
- Date of signature of the agreement specifying ownership of ERTs (if project proponent is not participant field(s) landowner)
- Date of submittal of Statement of Intent to ACR (if project proponent is participant field(s) landowner)
- Projected dates and intervals of revaluation of baseline inputs (at minimum once every 5 years)

- Projected dates of enrollment[12] and validation for new Participant Fields included in the project, if applicable[13] and actual dates as Participant Fields are enrolled.
- Demonstration that each Participant Field was in a Grassland or Shrubland land cover at least 10 years prior to time of executing the qualified Land Conservation Agreement.

The GHG Project Plan shall also include anticipated timeline for monitoring, reporting, and/or verification activities.

2.3.1 Start Date

The earliest Project Start Date for AFOLU projects is specified in the most recent version of the ACR Standard.

The Project Start Date for this project type is the date on which the qualified LCA is recorded. The project shall be submitted for listing with ACR no more than 3 years after the date upon which the qualified LCA is recorded.[14]

2.3.2 Crediting Period

The Project Crediting Period must begin no earlier than the project start date.[15] The Project Crediting Period is the timeframe in which changes are conservatively estimated to occur in a Participant Field's terrestrial carbon pools, i.e. the time as predicted by a biogeochemical model or field measurements[16] that soil carbon loss would continue to occur in the baseline scenario of

[12] The enrollment date is the date where a landowner entered into an agreement with the Project Proponent if not the landowner or the date where a new parcel was added to an existing GHG project plan where the landowner is the Project Proponent.

[13] Projects expecting to add new Participant fields over time must follow the requirements for Programmatic Design Approach in the ACR Standard.

[14] See ACR Standard Section 6A for Project Development Process, requirements for the step Project Listing. The Statement of Intent to develop or participate in a carbon project on the part of the land owner is separate from Project Listing and is required within 12 months of the LCA being recorded. Please contact ACR Administrator for a Statement of Intent template document or requirements.

[15] The start of the first reporting period may be after the project start date such that a project may forego credit issuance for a period of time in order to delay verification provided the validation occurs within 3 years of the start date.

[16] When changes in the soil carbon pool are not modeled and a default value 20 years is used for the parameter D, the transition period between soil organic carbon equilibrium states, the crediting period is also 20 years and cannot be renewed (See Appendix A).

conversion to Cropland. The Crediting Period must be at least 5 years but no more than 40 years and cannot be renewed.

The establishment of the baseline scenario as conversion to Cropland is valid for the duration of the Project Term following a successful initial validation. Updates to the project's baseline land management scenarios shall occur at least once every five years from the project start date.[17]

2.3.3 Project Term

The Minimum Project Term refers to the required duration of crediting, monitoring and reporting of Project Activities. The minimum Project Term for AFOLU projects with a risk of reversal is defined in the latest ACR Standard.

[17] Verifications are required at the same minimum frequency (5 years) but updates to the baseline cropland management scenario not required at every verification necessarily.

3 BASELINE DETERMINATION AND ADDITIONALITY

3.1 BASELINE DETERMINATION

The baseline scenario is the conversion of Grassland or Shrubland to Cropland. Baseline determination requires: 1) demonstration of the land-use scenario of cropland in the absence of the project activity and 2) description of the avoided cropland management practices. Baseline determination should be performed in conjunction with Section 3.2 Additionality Assessment. The baseline land use scenario of conversion to cropland, once determined, is static and made ex ante, with no adjustments during the Project Term. The baseline management scenario must be updated every 5 years, as outlined below in 3.1.2.

3.1.1 Determine Baseline Land-Use Scenario

All Participant Fields must demonstrate that Cropland is the likely land use scenario in the absence of the project activity with conversion of Grassland or Shrubland to Cropland occurring via either an identified or unidentified agent.

3.1.1.1 CONVERSION VIA AN UNIDENTIFIED AGENT

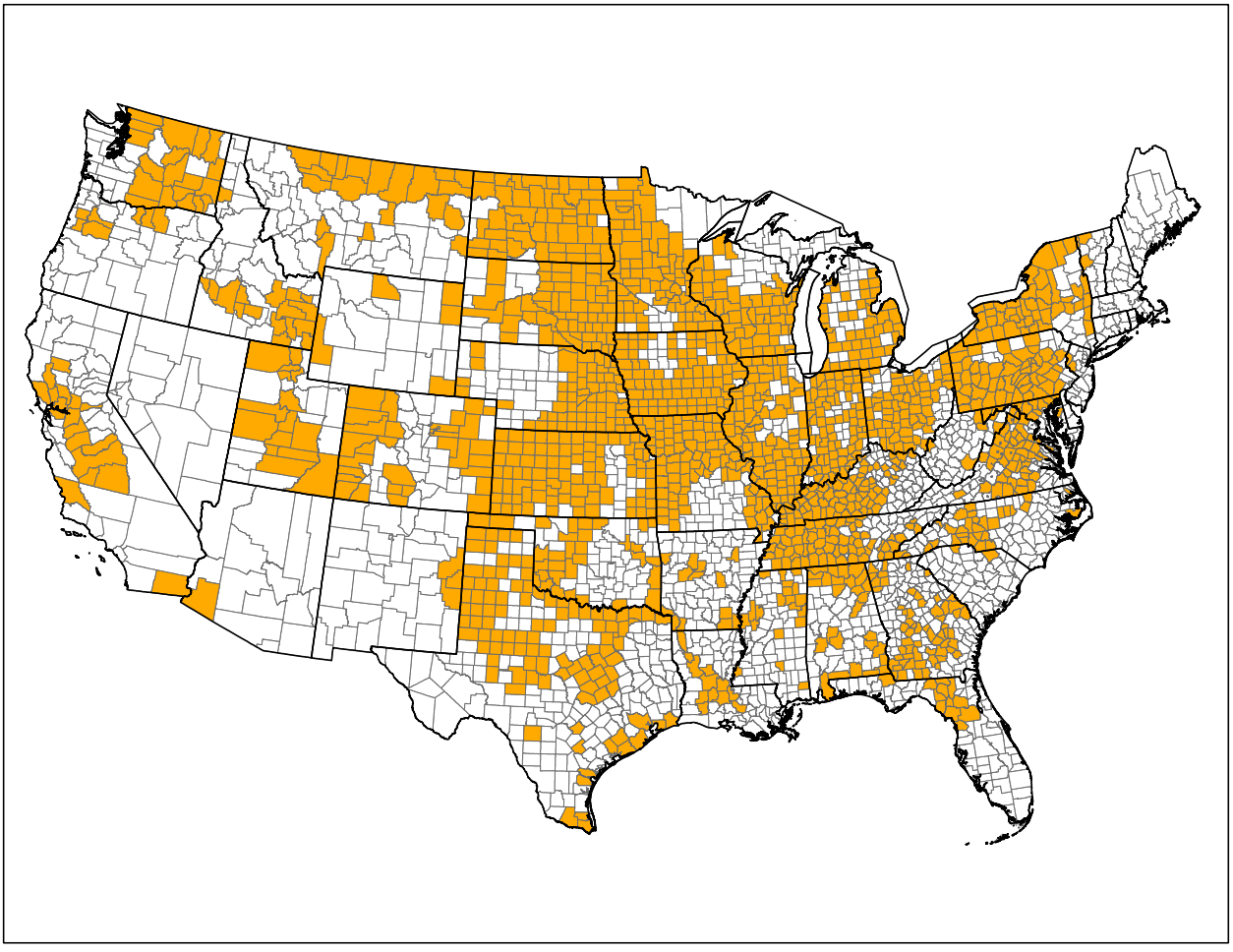
The baseline land use scenario is Cropland for all Participant Fields located in counties shown in the map below, listed in Appendix B and meeting all criteria in Section 1.2.

3.1.1.2 CONVERSION VIA AN IDENTIFIED AGENT

The baseline land use scenario is Cropland for all Participant Fields not located in counties shown in the map below and listed in Appendix B but: 1) meet all criteria in Section 1.2 and 2) are unambiguously identified in written rental or purchase offers with Cropland named as the intended use OR unambiguously identified in other documentation, subject to verifier and ACR review, including landowner affidavits, that can demonstrate a threat to conversion to cropland.

Figure 2: County Map for Unidentified Agents of Conversion, Baseline Land Use Scenario and Practice-Based Performance Standard

Project fields/parcels located in the counties highlighted in orange have a baseline scenario of cropland for unidentified agents of conversion and surpass the practice-based performance standard for demonstrating additionality. Project fields/parcels in white counties must determine the baseline land-use scenario and demonstrate additionality according to sections 3.1.1.2 and 3.2.2.2 respectively.



3.1.2 Determine Baseline Cropland Management Scenario

The baseline crop management scenario is determined ex ante and must be updated at minimum every 5 years from the project start date for the duration of the project term. This re-assessment updates the avoided crop management practices (i.e. the baseline) for the subsequent 5-year period. The baseline management scenario for the previous 5 years will not be altered. New baseline management scenarios are applied to all Participant Fields, including those previously enrolled, such that the baseline scenario for each Participant Field may change every 5 years.[18]

Required projected baseline management practices are listed below. Management practices (including as inputs to approved biogeochemical models) shall be informed from producer surveys conducted by government agricultural agencies or university extension offices[19]; the expert opinion of university extension personnel working in the region and systems of interest; personnel of a governmental agriculture agency field office (e.g., United States Department of Agriculture's Risk Management Agency, Farm Service Agency, Natural Resources Conservation Service) with jurisdiction in the Project Region; or Cropland management plans approved by a lending agency. Alternatively, a survey conducted by the Project Proponent may be used where the above sources are unavailable, unreliable or outdated, or aggregated at a scale larger than the Project Region.

The following baseline data should be defined:

- Field preparation techniques
- Tillage practices and intensity
- Typical cropping sequence (including fallow)
- Timing of planting and harvest of all crops
- Average applied N rates per identified crop
- Type of applied N and application methods employed
- Average application rates of other nutrients, or inputs, if applicable
- Irrigation practice and frequency
- Presence and type of cover crop
- Residue management practice
- Fire practice and frequency

[18] Verifications are required at the same minimum frequency (5 years) but updates to the baseline cropland management scenario not required at every verification necessarily.

[19] The smallest geographic extent for such data shall be used. For example, if fertilizer rates are available at the county level and state level, the county-level estimate shall be used.

- Other necessary inputs for modeling relevant biogeochemical processes
- Stocking rates, season dates for grazing, livestock type
- Equipment types and usage or volumes of fossil fuels by type

3.2 ADDITIONALITY ASSESSMENT

Avoided emissions from the project must be additional. Assessment of the additionality of a project will be made based on passing the tests cited below. These tests require the project proponent to demonstrate that the project activity is surplus to regulations and reduces emissions below "business-as-usual" for rates of conversion of grassland to cropland in the U.S.

- Regulatory Surplus Test (all participant fields)
- Practice Based Performance Standard (participant fields in counties in Appendix B) OR Implementation Barrier (participant fields in all other U.S. locations)

3.2.1 Regulatory Surplus Test

The project activity must meet the requirements of regulatory surplus set out in the latest ACR Standard. The project activity shall not be mandated by any law, statute or other regulatory framework. Specifically, there must not be any federal, state, or local regulations for the project region/area (pre-existing or subsequent), nor other pre-existing legally binding contracts, deed restrictions or encumbrances that require the project fields to be maintained as grassland other than the LCA that is recorded for the project (assessed at Project Start Date and upon initial verification). Furthermore, there must be no federal, state, or local regulation which would prohibit ongoing management of the project area as cropland in the baseline scenario (assessed at Project Start Date and initial verification).

Voluntary agreements that can be rescinded, such as rental contracts, are not considered legal requirements. Non-perpetual payment programs administered by government entities (e.g. Conservation Reserve Program) are not considered legal barriers to participation in a carbon offset program, given that the recordation of a new perpetual 99-year easement would disqualify the lands from continued participation in any such program. Enhancement payments administered by government entities (e.g. Environmental Quality Incentives Program or Conservation Stewardship Program) do not purport to pay for the preservation of grasslands, and thus, are considered compliant with this methodology's regulatory surplus requirements.

3.2.2 Practice-Based Performance Standard (if applicable)

3.2.2.1 UNIDENTIFIED AGENT

Participant Fields located in counties listed in Appendix B pass the Practice Based Performance Standard Test. Participant Fields which meet the eligibility criteria for this methodology can use the performance standard to demonstrate additionality without providing additional implementation barrier analysis.

An assessment of the rate at which unencumbered (available for conversion) Grassland and Shrubland acres as defined by the NCDL on a per county basis were converted to the Cropland land use type over a 10-year period, shows that the counties listed in Appendix B experience a high rate of loss of Grassland and Shrubland to Cropland.[20] Conversion of Grassland and Shrubland to Cropland is considered common practice in these areas, therefore the activity of encumbering fields within a qualified LCA in these counties is considered beyond business as usual.

3.2.2.2 IDENTIFIED AGENT

Participant Fields not located in counties listed in Appendix B may also pass the Practice Based Performance Standard Test when a specific agent of conversion has been identified. Participant Fields which meet the eligibility criteria for this methodology and can document likelihood to conversion via an identified agent and can use the performance standard to demonstrate additionality without providing additional implementation barrier analysis.

The county level analysis conducted to produce the maps in Appendix B may not reflect recent hot spots of conversion, real threats at a smaller scale than county level or where data is incorrect or lacking in the underlying databases. In instances where the Project Participants have received an offer to rent or purchase the Participant Fields for the purposes of cultivation or can

[20] Counties listed in Appendix B represent the top 50% of U.S. counties in terms of loss of available Grassland and Shrubland to Cropland. Loss rates in these counties represent areas where grassland loss in the United States is most extreme, relative to current conditions in the U.S. This calculation produced a county list of grassland conversion rates, normalized by the unique number of grassland/shrubland acres available for conversion in each county in each time step. It would be inaccurate to assume that one county is more at-risk just because more cumulative grassland acres were converted compared to another. By deriving the proportion of converted acres in relation to the grassland base acreage, the analysis avoids this potential bias. A brief description of the analysis to determine counties with high rates of conversion where Grasslands and Shrublands are most under threat can be found in Appendix B. The analysis will be updated every 5 years to reflect the current areas of highest conversion in the United States.

otherwise document such an offer, conversion of grassland and shrubland to cropland is considered common practice in this area (as it is a demonstrable threat), therefore the activity of encumbering fields within a qualified LCA is considered beyond business as usual.

Projects do not need to reassess additionality with each verification during their crediting period. However, ACR will re-assess the performance standard every 5 years.

4 STRATIFICATION

The objective of stratification is to reduce uncertainty of pool and emission estimates at the Project Area level.

When the DAYCENT model (or other approved process based biogeochemical models) are used for quantification of carbon pools, spatial heterogeneity must be accounted for in both baseline and project scenarios via stratification, for example, soil type, climate, cropping scenario and/or previous land use history. For modeling efforts, this requires parameterizing and running the model for each stratum and estimating parameter values separately for each category. The stratification approach must be included in the GHG Project Plan and is subject to verifier review during project validation.

When soil sampling is conducted in the Project Area and this area is not homogeneous, stratification may be used to improve the precision of carbon stock estimates. For estimation of baseline carbon stocks, strata may be defined by parameters that are key variables for estimating changes in baseline and project carbon stocks, for example: soil type, climate, cropping scenario and/or previous land use history.

Stratification accuracy, precision and details such as sample design and plot selection shall be determined following best practices and detailed in the GHG Project Plan. Stratification must consider the biogeochemical and/or empirical models (see Chapter 5) that will be applied for the methodology, where each stratum can be represented by a unique model parameterization. It is not necessary to use the same stratification categories for each pool or for baseline and project scenarios.

5 USE OF MODELS FOR QUANTIFICATION OF GHG EMISSIONS

Under this methodology, the following classes of models shall be used to quantify carbon pools and GHG emissions:

1. Process based biogeochemical models (e.g. DAYCENT)
2. Empirical models based on time series measurements and proxy sites

The DAYCENT model is approved for use with this methodology throughout the continental United States, excluding Alaska. Additional process based biogeochemical models may be approved by ACR[21], according to the criteria specified in the ACR Standard, Section A.6.

Empirical models may be approved on a case by case basis where available. Please contact ACR for approval of new empirical models for use with this methodology. Proposed models shall, at a minimum, meet the following criteria:

- Be published in peer-reviewed, scientific literature;
- Be empirically based;
- Be able to account for changes to soil organic matter and nutrient dynamics that occur following the conversion of Grassland or Shrubland to Cropland;
- Be able to estimate size of relevant carbon pools on an annual basis (mass of carbon/year);
- Be able to make predictions at the scale of a Stratum or Project Area, whichever is smallest;

[21] Proposed biogeochemical or empirical models will be reviewed by ACR and/or Winrock staff as well as ACR's AFOLU Technical Committee. ACR's AFOLU Technical Committee supports the objective of bringing to market high-quality AFOLU carbon offsets based on scientifically sound methodologies. The AFOLU Technical Committee will provide ACR independent advice on a range of agriculture, forestry, grassland, rangeland, wetland and other land-use topics needed for greenhouse gas (GHG) methodologies being brought to ACR and/or developed by Winrock. ACR approves new methodologies, tools and significant methodology modifications through a process of public consultation and expert peer review. The AFOLU Technical Committee will not replace that process, but rather complement it. This is a standing committee with a subset of Committee members, serving on two-year terms, consulted for specific issues that match their expertise.

- A baseline site must be identified and accessible on which one or more parameters are monitored in the baseline scenario; baseline and project site must have similar soil types, climate, and management history[22].
- Directly measure soil carbon (soil carbon loss) in baseline and project sites OR dependent variable is soil carbon (soil carbon loss) and relationship between proxy variable and emissions must be significant at $P < 0.1$ and unbiased (i.e. with minimal trend in residuals)
- Uncertainty in predicted soil carbon loss (emissions - dependent variable) is known and calculated as the root mean squared error (RMSE);
- Be validated for the Project Region to demonstrate that the model can accurately estimate each carbon pool and GHG source in the Project Region including the management systems identified in both the project and baseline scenario and regional weather and climate conditions (average annual precipitation and temperature) applicable to the Project Area. Model validation shall use peer-reviewed or other quality-controlled data (i.e. such as that collected as part of a Government soils inventory or experiment), appropriate for the Project Region. For an example see Ahlering et al. (2016) or Chamberlain et al. (2011).
- Be based on a time series experimental design that includes cropped and grassland sites and t=0 is the conversion event

Output from models should include estimates of uncertainties associated with all pools and sources. In cases where variances are not included in model outputs, additional uncertainty analyses should be performed (e.g., Monte Carlo simulations). In cases where input variances can be calculated through Monte Carlo simulations, then these shall be performed and reported as well. See Section 6.5 Uncertainty Assessment and Conservativeness.

[22] Suitability of the project and baseline sites ultimately to the discretion of the verifier and ACR validation review

6 QUANTIFICATION OF GHG EMISSIONS REDUCTIONS

6.1 QUANTIFICATION OF BASELINE GHG EMISSIONS

Baseline GHG emissions for all Participant Fields in the project area in a single year are calculated according to Equation 1. Baseline emissions for a single Participant Field are calculated according to Equation 2.

Equation 1: Baseline Emissions

$$\mathbf{BE_y} = \sum_{\mathbf{p}}^{\mathbf{P}} \mathbf{BE_{p,y}}$$

WHERE

BE_y	Baseline emissions in year y, y = 0 at project start date; $MTCO_2e$
$BE_{p,y}$	Baseline emissions from Participant Field p in year y; $MTCO_2e$
P	Total number of Participant Fields in the Project Area
p	Participant Field
y	Year

Equation 2: Baseline Emissions from Each Participant Field

$$\mathbf{BE_{p,y}} = \left(\mathbf{C_{AGB,BL_{p,y-1}}} - \mathbf{C_{AGB,BL_{p,y}}} + \mathbf{C_{BGB,BL_{p,y-1}}} - \mathbf{C_{BGB,BL_{p,y}}} + \mathbf{C_{SOC,BL_{p,y-1}}} - \mathbf{C_{SOC,BL_{p,y}}}\right) + \mathbf{E_{N_2O,BL_{,p,y}}} + \mathbf{E_{FERM,BL\,p,y}} + \mathbf{E_{FF_{,p,y}}}$$

WHERE

$BE_{p,y}$	Baseline emissions from Participant Field p in year y; $MTCO_2e$

$C_{AGB,BL_{p,y}}$	Carbon stock of above-ground biomass for Participant Field **p**, in year **y**, in the baseline scenario; $MTCO_2e$ (optional)
$C_{BGB,BL_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field **p**, in year **y**, in the baseline scenario; $MTCO_2e$ (optional)
$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field **p**, in year **y**, in the baseline scenario; $MTCO_2e$
$E_{N_2O,BL_{p,y}}$	N_2O emissions from Participant Field **p**, in year **y** in the baseline scenario for; $MTCO_2e$
$E_{FERM,BL\ p,y}$	CH_4 emissions from livestock – enteric fermentation in Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$
$E_{FF,p,y}$	Emissions due to the use of fossil fuels in agricultural management in field **p** and year **y** in the baseline scenario; $MTCO_2e$ (optional)

6.1.1 Accounting Baseline Emissions from Aboveground Biomass (Woody and Non-woody)

Accounting for this pool is optional. If included, woody biomass is non-tree. If included, in the baseline scenario, projects must account for remaining Grassland and Shrubland aboveground biomass as Participant Fields are converted over time, as well as the aboveground biomass in annual crops grown following conversion. The aboveground biomass in the baseline scenario shall be calculated each year according to Equation 3.

Equation 3: Baseline Above Ground Biomass

$$C_{AGB,BL_{p,y}} = C_{AGB_{grass},BL_{p,y}} + C_{AGB_{crop},BL_{p,y}}$$

WHERE

$C_{AGB,BL_{p,y}}$	Carbon stock of aboveground biomass in Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$
$C_{AGB_{grass},BL_{p,y}}$	Remaining carbon stock of pre-existing aboveground biomass for Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$

$C_{AGB_{crop},BL_{p,y}}$	Carbon stock of aboveground crop biomass in Participant Field p in year y in the baseline scenario, as calculated from Section 6.1.1.2; $MTCO_2e$

6.1.1.1 CARBON STOCKS OF WOODY AND NON-WOODY, NON-CROP ABOVEGROUND BIOMASS ($C_{AGB, GRASS,BL,P,Y}$)

In the conversion of Grassland to Cropland, this methodology treats carbon in aboveground, biomass[23] to be primarily released to the atmosphere in the first 5 years following conversion. Projects that opt to account for the removal of aboveground biomass in conversion to Cropland will do so by first quantifying initial carbon stocks for above-ground grass and shrub biomass in the project scenario (see Section 6.2.1). That is, for projects accounting for the loss of aboveground biomass due to conversion, the initial (year y=0) carbon stocks in aboveground biomass for each Participant Field in both the project and baseline scenarios shall be equal and based upon the estimation of initial carbon storage in aboveground biomass.

The loss of carbon from aboveground biomass due to conversion shall be based upon the proportion of that field that is converted and the decomposition of biomass in the portion of the field that is converted. The most conservative scenario is that biomass would decompose as slow as litter in an untilled Cropland.[24] Project Proponents may use a less conservative estimate of 100% decomposition of aboveground biomass the year following conversion in cases where tillage is used in the baseline scenario. The aboveground biomass estimate, for biomass from the project scenario, shall be the annual peak biomass, i.e. maximum annual growth prior to grazing, harvest or other disturbance.

Equation 4: Baseline Carbon Stocks of Woody and Non-Woody, Non-Crop Above Ground Biomass Loss

$$C_{AGB_{grass},BL_{p,y}} = C_{AGB,PR_{p,y}} \times \left(1 - \sum_{t=0}^{y} FC_{p,t,y}\right) + C_{AGB,PR_{p,y}} \times \sum_{t=0}^{y} \left(FC_{p,t,y} \times e^{(-0.77 \times (y-t))}\right)$$

WHERE

[23] Because this methodology treats the loss of aboveground biomass upon conversion as lost to the atmosphere over a 5-year period, projects are permitted to account for aboveground biomass that is lost upon conversion to Cropland. However, project may not include aboveground Tree biomass in this calculation as the decay period is much longer. Tree biomass removed from the Participant Field during conversion in the baseline scenario may be expected to decay over several years and/or some portion could remain intact over long periods in harvested wood products. This methodology conservatively excludes accounting for the loss of aboveground Tree biomass in the baseline scenario.

[24] Most fields are prepared for conversion to Cropland by destroying existing aboveground biomass through herbicide application and plowing, although it is possible to direct seed into Grassland.

$C_{AGB_{grass},BL_{p,y}}$	Carbon stock of aboveground woody and non-woody biomass from Participant Field **p** in year **y** in the baseline scenario; MT CO_2.
$C_{AGB,PR_{p,y}}$	Carbon stock of aboveground non-woody biomass for Participant Field **p**, in the project scenario, as determined from Section 6.2.1; $MTCO_2e$
$FC_{p,t,y}$	The proportion of Participant Field **p** that is converted to Cropland in year **t**, time of conversion, in year **y** of the baseline scenario. If the entire field will be converted in year 1, **FCp,t,y** =1, d.u.
$e^{(-0.77 \times (y-t))}$	Decay rate of aboveground biomass following conversion. Note that because conversion often occurs over multiple years, and decay is a nonlinear function, it is necessary to track carbon loss from a given year's conversion event. The decay rate (0.77) is based on leaf decomposition in no-till Cropland (Kochsiek et al. 2009)
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 40 years

6.1.1.2 CARBON STOCKS OF ABOVEGROUND CROP BIOMASS ($C_{AGB,CROP,BL,P,Y}$)

In the baseline scenario, the aboveground biomass each year is assumed equal to biomass losses from harvest and mortality in that same year. There is no carryover of aboveground crop biomass between years. There is no net accumulation of aboveground biomass stocks once areas have been converted for the duration of the Project Crediting Period (IPCC GL AFOLU 2006, Ch. 5, 5.2.1.1). After 100% conversion for a Participant Field, $C_{AGB_{crop},BL_{p,y}}$ will remain static, except in rotational cropping systems where aboveground biomass values will conform to each crop year.

$C_{AGB_{crop},BL_{b,y}}$ can be estimated by either:

- Approved models (see Section 5)[25]
- Field measurements for crop or forage productivity and Project Region published in peer reviewed literature
- Agricultural statistics for crop or forage productivity and Project Region, including State Agricultural Extension Offices

[25] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{AGB_{crop},BL_{b,y}}$.

- Values for the annualized average dry matter ($DMBL,p,y$) and carbon fraction (CFb) for each crop type (Equation 6). Values for $DMBL,p,y$ can be obtained from fixed ratio of crop yield to plant biomass, the Harvest Index ratio, available from peer reviewed literature, or government or University extension for crop and region of interest. A default harvest index of 0.50 can be used for maize (Ciampitti and Vyn 2012), of 0.46 for soybean (Johnson et al. 2006), and 0.45 for wheat (Johson et al. 2006). 5-year average crop yields must be used, and yield data obtained from government or extension crop yield reports for the smallest available administrative unit containing the Participant Field, e.g., county.

Carbon stocks in aboveground crop biomass in the baseline scenario should be calculated for each Participant Field in the Project Area, each year according to Equations 5 and 6.

Equation 5: Baseline Above Ground Crop Biomass

$$C_{AGB_{crop},BL_{p,y}} = \sum_{b}^{B} C_{AGB_{crop},BL_{b,y}}$$

WHERE

$C_{AGB_{crop},BL_{p,y}}$	Carbon stock of aboveground crop biomass for Participant Field **p** in the baseline scenario in year **y;** $MTCO_2e$
$C_{AGB_{crop},BL_{b,y}}$	Carbon stock of aboveground crop biomass in the baseline for crop type **b** in year **y**; $MTCO_2e$
B	Total number of crop types

Equation 6: Baseline Above Ground Crop Biomass for Crop Type b

$$C_{AGB_{crop},BL_{b,y}} = DM_{BL,b,y} \times CF_b \times \frac{44}{12} \times A_b$$

WHERE

$C_{AGB_{crop},BL_{b,y}}$	Baseline above ground crop biomass for crop type b
$DM_{BL,b,y}$	Annualized average dry matter in the baseline for crop type **b** in year **y**; MT dry matter per ha
CF_b	Carbon fraction of dry matter for biomass type **b**; MT-C (MT dry matter)$^{-1}$

A_b	Area of crop type b; hectares
$\frac{44}{12}$	Ratio of molar mass of CO_2 to C

6.1.2 Accounting Baseline Emissions from Belowground Biomass

Accounting for this pool is optional. If included, woody biomass is non-tree (i.e. shrubs). The conversion of Grassland to Cropland is expected to result in the removal or rapid decomposition of belowground biomass.

$C_{BGB,BL_{p,y}}$ can be estimated by either:

- Approved models (see Section 5)[26]
- $C_{AGB,BL_{p,y}}$ (Equation 3) and appropriate root-to-shoot ratios for crop and woody and non-woody components

Below-ground biomass carbon stocks are assumed to decompose at a rate specified in Equation 8 upon conversion to Cropland in the baseline scenario.

Equation 7: Baseline Belowground Biomass

Carbon stocks in belowground biomass in the baseline shall be calculated for each Participant Field in the Project Area according to Equation 7.

$$C_{BGB,BL_{p,y}} = C_{BGB_{grass},BL_{p,y}} + C_{BGB_{crop},BL_{p,y}}$$

WHERE

$C_{BGB,BL_{p,y}}$	Carbon stock of belowground biomass in Participant Field p in year y in the baseline scenario; $MTCO_2e$
$C_{BGB_{grass},BL_{p,y}}$	Carbon stock of woody and non-woody belowground biomass for Participant Field p in year y in the baseline scenario; $MTCO_2e$

[26] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB,BL_{p,y}}$.

$C_{BGB_{crop},BL_{p,y}}$	Carbon stock of belowground crop biomass in Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$

6.1.2.1 ACCOUNTING CARBON STOCKS OF WOODY AND NON-WOODY, NON-CROP BELOWGROUND BIOMASS ($C_{BGB,GRASS,P,Y}$)

Projects that opt to account for the decomposition or removal of belowground biomass in conversion to Cropland will do so by first quantifying initial carbon stocks for belowground woody and non-woody biomass in the project scenario (see Section 6.2.2 Below-Ground Biomass). That is, for projects accounting for the loss of belowground biomass due to conversion, the initial (year y=0) carbon stocks in belowground biomass for each Participant Field in both the project and baseline scenarios shall be equal and based upon the estimation of initial carbon storage in belowground biomass.

The loss of carbon from belowground biomass due to conversion shall be based upon the proportion of that field that has been converted ($FC_{p,t,y}$) and the decomposition of biomass in the portion of the field that was converted. The decomposition rate is specified in Equation 8.

Equation 8: Baseline Pre-existing Belowground Grass Biomass

$$C_{BGB_{grass},BL_{p,y}} = C_{BGB,PR_{p,y}} \times \left(1 - \sum_{t=0}^{y} FC_{p,t,y}\right) + C_{BGB,PR_{p,y}} \times \sum_{t=0}^{y} FC_{p,t,y} \times e^{(-1.41 \times (y-t))}$$

WHERE

$C_{BGB_{grass},BL_{p,y}}$	Carbon stock of belowground woody and non-woody biomass from Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$
$C_{BGB,PR_{p,y}}$	Carbon stock of belowground biomass for Participant Field **p**, in year **y,** in the project scenario, as determined from Section 6.2.2; $MTCO_2e$
$FC_{p,t,y}$	The cumulative proportion of Participant Field **p** that has been converted to Cropland in year **t**, time of conversion, as of year **y** in the baseline scenario. If the entire field will be converted in year 1, $FC_{p,t,y}$ =1, d.u.
$e^{(-1.41 \times (y-t))}$	The decay function for belowground biomass following conversion. Note that because conversion often occurs over multiple years, and decay is a nonlinear function. It is necessary to track carbon loss from a given year's conversion event, and then sum the loss from all years, as shown in Equation 8. The decay rate (1.41) is based on average grass root decomposition from 46 studies (Silver and Miya 2001). For woody biomass, a decay rate of 0.44

	should be used for broadleaved species and a decay rate of 0.30 should be used for conifer species (Silver and Miya 2001)[27]
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 40 years

6.1.2.2 ACCOUNTING CARBON STOCKS OF BELOWGROUND CROP BIOMASS

$C_{BGB_{crop},BL_{b,y}}$ can be estimated by:

- Approved models (see Section 5)[28]
- Field measurements for crop or forage productivity and Project Region published in peer reviewed literature
- Agricultural statistics for crop or forage productivity and Project Region, including State Agricultural Extension Offices
- $C_{AGB_{crop},BL_{b,y}}$ and suitable root-to-shoot ratio for crop and region (Equation 9). For maize a default value of 0.07 should be used.[29]

If using a root-to-shoot ratio, carbon stocks in belowground crop biomass in the baseline scenario should be calculated for each Participant Field in the Project Area, each year, and for each crop according to Equation 9.

Equation 9: Baseline Belowground Crop Biomass Using Root to Shoot

$$C_{BGB_{crop},BL_{p,y}} = \sum_{b}^{B} R_b \times C_{AGB_{crop},BL_{b,y}}$$

[27] Project Proponents may replace the default decomposition rate with a site-specific value based on peer reviewed literature.

[28] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[29] This is based on a comprehensive analysis of root-to-shoot ratios in maize (Amos and Walters 2006). The review of root-to-shoot ratio in maize provides a value based on an analysis that does not include grain or cobs in its measure of shoot; our default value represents a modified value that can be used to calculate root biomass based on total aboveground biomass, including grain and cobs (Amos and Walters 2006).

WHERE

$C_{BGB_{crop},BL_{p,y}}$	Carbon stock of belowground crop biomass for Participant Field p in the baseline scenario in year y; $MTCO_2e$
R_b	Root carbon-to-shoot carbon ratio of (crop) biomass type b; d.u.
$C_{AGB_{crop},BL_{b,y}}$	Carbon stock of aboveground crop biomass of crop type b and year y of the baseline scenario, as calculated in 6.1.1; $MTCO_2e$
B	Total number of crop types

6.1.3 Accounting Baseline Emissions from Soil Organic Carbon

Accounting for this pool is required. The soil carbon pool is expected to be the primary source of emissions for the project activity, as soil carbon accounts for approximately 90% of ecosystem carbon in Grassland and rangeland systems (Schuman et al. 2001).

$C_{SOC,BL_{p,y}}$ can be estimated by:

- Approved models (see Section 5).[30] This method assumes emissions from SOC following conversion proceed according to the best fit decay curve to the model SOC and for the time up until when SOC levels in the model are changing by no more than ± 3%, not to exceed 40 years.
- Direct measurement of SOC according to requirements in ISO 10381-2:2003 Soil quality – sampling – Part 2: Guidance on sampling techniques.[31] This method assumes the emissions from SOC following conversion proceed linearly for 20 years (i.e., D = 20), at which point a new equilibrium level of SOC is reached in the converted state. A linear EF function may be used per the IPCC GL AFOLU 2006 (adapted from Eq. 2.25, Ch2, p 2.30).[32,33]

[30] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[31] Please see Section B.1.1 Stratification.

[32] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_02_Ch2_Generic.pdf

[33] Determination of the equilibrium SOC value resulting after a linear decay of 20 years requires the selection of an appropriate proxy site or chronosequence study. Site similarity or appropriateness must be

- Direct measurement of SOC according to requirements in ACR Tool for Estimation of Stocks in Carbon Pools and Emissions from Emission Sources.[34] This method assumes the emissions from SOC following conversion proceed linearly for 20 years (i.e., D = 20), at which point a new equilibrium level of SOC is reached in the converted state. A linear EF function may be used per the IPCC GL AFOLU 2006 (adapted from Eq. 2.25, Ch2, p 2.30).[35]

Whatever approach is deployed, estimates should be available to the affected depth at which SOC changes are expected to occur in response to baseline activities.[36] The affected depth chosen for sampling or modeling shall be justified to the validator using peer-reviewed scientific data and/or professional expert opinion. Further, direct sampling shall separate and exclude visible root biomass from SOC estimates. If models are utilized, they shall similarly be calibrated with samples that have excluded visible root biomass.

Equation 10: Total Soil Organic Carbon in the Baseline Scenario

Through one or a combination of the above approaches, total soil organic carbon stocks in the baseline scenario for each Participant Field in the Project Area shall be calculated according to Equation 10.

$$C_{SOC,BL_{p,y}} = \sum_{i}^{p,i} C_{SOC_{i,y=0}} \times A_{p,i} \times (1 - EF_{t,y}) \times FC_{p,y}$$

WHERE

$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field p in the baseline scenario in year y; $MTCO_2e$
$C_{SOC_{i,y=0}}$	Total initial (year y=0) soil organic carbon stock for soil stratum i, fixed for project duration; $MTCO_2e\ (ha)^{-1}$
$A_{p,i}$	Area of participant field p in soil strata i; hectares
$EF_{t,y}$	Emission factor for the fraction of soil organic carbon pool remaining t years since conversion to Cropland in year y; d.u.

demonstrated satisfactorily at the time of validation or a literature study used which meets the standards of best practice for soil chronosequence studies by the USGS e.g. https://pubs.usgs.gov/bul/1648/report.pdf.

[34] Please see Section B.1.1 Stratification.

[35] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_02_Ch2_Generic.pdf

[36] Recent syntheses commonly find losses of soil carbon down to 1 meter (Sanderman et al. 2017).

$FC_{p,y}$	Proportion of Participant Field p that has been converted to Cropland in the baseline scenario for year y. If the entire field will be converted in year 1, $FC_{p,y}$=1, d.u.
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 40; years

When direct measurement approaches are used to estimate $C_{SOC,BL_{p,y}}$, $EF_{t,y}$ for each soil organic carbon stratum may be determined by:

- Equation 11
- A peer-reviewed study of soils and a region similar to the Project Area or Project Region that examines long-term changes in soil carbon, with samples from sites that have a minimum of 20 years since conversion to cropland.
- An empirical result from field measurements at sites that have and have not been converted to Cropland but are otherwise materially similar to each other and to the Project Area (e.g. in soil type and climate), provided that soil samples are collected from the relevant soil layers that would be affected by the conversion process and baseline activity. A sample-based emission factor shall not be projected for a period of time longer than the Cropland sample sites have been converted to Cropland, and at a minimum shall be measured following the same management treatments for duration of 5 years. Empirical data on soil carbon emissions shall be adjusted for uncertainty as described in Section 5.2.3.5 of IPCC GL AFOLU 2006.
- Approved process based biogeochemical models (see Section 5), e.g., DAYCENT.

Equation 11: Emission Factor for Decay Rate of SOC Following Conversion

$$EF_{t,y} = \frac{1 - (FSOC_{LU} \times FSOC_{MG} \times FSOC_{IN})}{D} \times t$$

WHERE

$EF_{t,y}$	Emission factor describing the fraction of soil organic carbon pool remaining t years since conversion to Cropland in year y; d.u.
$FSOC_{LU}$	Fraction of soil organic carbon pool remaining after transition period, accounting for land use factors; d.u.
$FSOC_{MG}$	Fraction of soil organic carbon pool remaining after transition period, accounting for management factors; d.u.

$FSOC_{IN}$	Fraction of soil organic carbon pool remaining after transition period, accounting for input of organic matter; d.u.
D	Transition period for soil organic carbon, time period for transition between equilibrium SOC values, default value of 20; years
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 20; years

6.1.4 Accounting Baseline Emissions from Soil N_2O

Accounting for this pool is required. Direct and indirect soil N_2O emissions in the baseline scenario result from nitrogen fertilizer application, both synthetic and organic, as well as the presence of N-fixing plant species such as legumes. Quantification of indirect N_2O emissions from nitrogen fertilizer application is highly uncertain. GHG benefits from this pool cannot be assured to be real and are therefore conservatively excluded from both the baseline and project scenario.[37]

$E_{BL,N_2O_{p,y}}$ may be determined by:

- Approved models (see Section 5).[38]
- Equations 12, 13 and 14.[39]

Equation 12: Baseline N_2O Emissions

Baseline emissions of N_2O from the application of nitrogen fertilizer can be calculated for each Participant Field in the Project Area according to Equation 12.

$$\mathbf{E_{BL,N_2O_{p,y}} = E_{BL,N_2O,direct_{p,y}} = \left(F_{BL,SN_{p,y}} + F_{BL,ON_{p,y}}\right) \times EF_N \times \frac{44}{28} \times GWP_{N_2O}}$$

WHERE

[37] Nitrogen application is assumed to be higher in the baseline scenario, crop cultivation, relative to the project scenario, grassland with or without grazing.

[38] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop,BL_{b,y}}}$.

[39] CDM A/R Methodological Tool, Estimation of direct nitrous oxide emission from nitrogen fertilization. https://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-07-v1.pdf

$E_{BL,N_2O_{p,y}}$	Total N_2O emissions from Participant Field p in year y; $MTCO_2e$
$E_{BL,N_2O,direct_{p,y}}$	Direct N_2O emissions from the addition of N to Participant Field p in the baseline scenario for year y; $MTCO_2e$
$F_{BL,SN_{p,y}}$	Mass of synthetic fertilizer nitrogen applied to Participant Field p in the baseline scenario in year y adjusted for volatilization as NH_3 and NO_X; (See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$F_{BL,ON_{p,y}}$	Mass of organic N amendments applied to Participant Field p in the baseline scenario in year y adjusted for volatilization as NH_3 and NO_X; See Section 3.1.2. Baseline Cropland Management Scenario); MT N
EF_N	Emission Factor for emission from N inputs; MT N_2O-N (MT N input)$^{-1}$. A default emission factor of 0.0254 (2.54%) of applied synthetic fertilizer N and 0.02 (2%) of applied organic fertilizer N can be assumed to be emitted (Davidson 2009).
$\frac{44}{28}$	Ratio of molecular weights of N_2O to N; MT N_2O (MT N)$^{-1}$
GWP_{N_2O}	Global Warming Potential for N_2O[40]

Equation 13: Baseline Mass of Synthetic Fertilizer Nitrogen

$$F_{BL,SN_{p,y}} = \sum_{j}^{J} M_{BL,SN_{p,j,y}} \times N_{BL,SN_j} \times (1 - Frac_{SN})$$

WHERE

$F_{BL,SN_{p,y}}$	Mass of synthetic fertilizer nitrogen applied to Participant Field p in the baseline scenario in year y adjusted for volatilization as NH_3 and NO_X; (See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{BL,SN_{p,j,y}}$	Mass of synthetic fertilizer type j applied to Participant Field p in year y; (See Section 3.1.2. Baseline Cropland Management Scenario); MT fertilizer

[40] Project proponents shall refer to the ACR Program Standard for the approved IPCC GWP for nitrous oxide value, which will be updated periodically as new information becomes available.

N_{BL,SN_j}	Nitrogen content of synthetic fertilizer type **j**; MT N (MT input)$^{-1}$
$Frac_{SN}$	Fraction of synthetic fertilizer nitrogen that volatilizes as NH_3 and NO_X;
J	Total number of synthetic **N** inputs of type **j**

Equation 14: Baseline Mass of Organic Fertilizer Nitrogen

$$F_{BL,ON_{p,y}} = \sum_{k}^{K} M_{BL,ON_{p,k,y}} \times N_{BL,ON_k} \times (1 - Frac_{ON})$$

WHERE

$F_{BL,ON_{p,y}}$	Mass of organic **N** amendments applied to Participant Field **p** in the baseline scenario in year **y** adjusted for volatilization as NH_3 and NO_X; (See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{BL,ON_{p,k,y}}$	Mass of organic **N** amendment type **k** applied to Participant Field **p** in year **y**; (See Section 3.1.2. Baseline Cropland Management Scenario); MT fertilizer
N_{BL,ON_k}	Nitrogen content of organic **N** amendment type **k**; MT-N (MT inputs)$^{-1}$
$Frac_{ON}$	Fraction of organic amendment nitrogen that volatilizes as NH_3 and NO_X;
K	Total number of organic **N** amendments types

6.1.5 Accounting Baseline Emissions from Enteric Fermentation

Livestock, such as cattle, bison and sheep, produce CH_4 due to enteric fermentation in their rumen. Enteric fermentation emissions vary by species, breed, animal size, feed, environment and management systems (Ominski et al. 2007). Estimates of enteric fermentation can also vary widely depending on the level of specificity input data and use of defaults (Ominski et al. 2007). It is therefore encouraged that Project Proponents utilize the most representative input data where possible. Further, calves less than 6 months in age are assumed to have zero CH_4 emissions as their diet will be primarily milk (US EPA 2013).

Accounting for GHG emissions from livestock enteric fermentation is required when livestock would be present in the baseline scenario. In some areas, it is common practice for livestock to graze cultivated fields in the winter or to graze stover following harvest. It must be shown at time of validation that:1) winter grazing is common practice in the region as part of the baseline crop management scenario, per the requirements in section 3.1.2, and 2) winter grazing is feasible and likely at the specific project location because cattle are already present or have been present in the project area[41] or LCA area.

Estimates of enteric CH_4 emissions are restricted to rangeland/pasture manure systems where manure is left unmanaged once deposited by livestock per the Applicability Conditions in Section 1.2. It is recognized that in Grassland ecosystems, the net contribution of livestock in the system may be net GHG sequestration (Liebig et al. 2010). Any stimulation to vegetation growth from soil nutrient amendments, grazing and/or natural manure management, present from pre-project conditions/practices, are assumed to be captured through the model parameterization of soil and biomass carbon pools in the project scenario. Any net sequestration benefits from these activities in the project scenario are conservatively excluded from this methodology but could be eligible for ERTs under a separate but complimentary Grazing Land and Livestock Management methodology. Manure deposited by livestock present in the project scenario shall be accounted for in Soil Nitrogen Emissions, Section 6.1.4 Soil Nitrogen Emissions. Baseline emissions from livestock due to enteric fermentation shall be calculated for each Participant Field in the Project Area according to Equation 15 and 16.

Equation 15: Baseline Enteric Fermentation

$$E_{Ferm,p,y} = \sum_{l}^{L} P_{p,l} \times EF_{l} \times GD_{p,l,y} \times GWP_{CH_4} \div 1,000$$

WHERE

$E_{Ferm,p,y}$	CH_4 emission from enteric fermentation due to livestock on Participant Field p in year y; $MTCO_2e$
L	Total number of livestock types in project scenario
$P_{p,l}$	Population of livestock type l on Participant Field p; head
$GD_{p,l,y}$	Grazing days per livestock type l on Participant Field p in year y; grazing days

[41] These emissions are conservatively excluded in the baseline scenario if the project scenario does not also include grazing. These emissions are conservatively excluded if it cannot be demonstrated that grazing was already occurring within the project boundary or by the land manager. These emissions are conservatively excluded if it cannot be demonstrated that grazing is both feasible and likely for the project area in addition to common practice in the region.

EF_l	Enteric CH_4 emission factor for livestock type l; $kgCH_4$ ($head^{-1}$) (grazing day^{-1})
GWP_{CH4}	Global warming potential for CH_4 (See ACR Standard)
1,000	Conversion kg to MT

Equation 16: Enteric Emission Factor per Head of Livestock

$$EF_l = \frac{GE \times \left(\frac{Y_m}{100}\right)}{55.65}$$

WHERE

EF_l	Enteric methane emission factor per head of livestock
GE	Gross energy intake MJ $head^{-1}$ day^{-1}
Y_m	Methane conversion factor, per cent of gross energy in feed converted to methane
55.65	Energy content of methane; MJ/kg CH_4

6.1.6 Accounting Baseline Emissions from Fossil Fuels

Accounting for GHG emissions from fossil fuels is optional. The combustion of fossil fuels used in farm machinery, and potentially construction equipment, to assist with the conversion and ongoing crop management process produces emissions that may optionally be accounted for with Equation 17 and included in Equation 2.

Equation 17: Baseline Fossil Fuel Emissions

Projects that elect to account for fossil fuel emissions in the baseline scenario shall be calculated according to Equation 17.

$$E_{BL,FFp,y} = \sum_{v}^{V} \sum_{f}^{F} \left(FF_{BL_{p,v,f,y}} \times EF_{f,y} \right)$$

WHERE

$E_{BL,FFp,y}$	Emissions due to the use of fossil fuels in agricultural management in the baseline scenario on Participant Field p in year y; $MTCO_2e$
$FF_{BL_{p,v,f,y}}$	Volume of fossil fuel consumed in the baseline scenario on Participant Field p in vehicle/equipment type v with fuel type j during year y; (See Section 3.1.2. Baseline Cropland Management Scenario); liters
EF_f	Emission factor for the type of fossil fuel combusted in vehicle or equipment, j. (See U.S. Energy Information Agency, EIA)[42]
v	Type of vehicle/equipment
V	Total number of types of vehicle/equipment used in the project activity
f	Type of fossil fuel
F	Total number of fuel types

6.2 QUANTIFICATION OF PROJECT GHG EMISSIONS

The greatest net GHG benefit from the project activity is anticipated to be the avoided release of SOC. This methodology conservatively assumes that avoided conversion results in the maintenance (without increase) of carbon stocks in the pools of soil organic carbon, and above-ground and below-ground biomass remain at steady state throughout the project scenario. That is, for

[42] https://www.eia.gov/environment/emissions/co2_vol_mass.php

each included pool, projects must estimate initial carbon stocks and are only allowed to generate credits based on avoided losses from these stocks (i.e., assuming the change in these stocks is on average, zero), rather than accounting for activities that may increase these stocks.

Project GHG emissions for all Participant Fields in the project area in a single year are calculated according to Equation 18. Project GHG emissions for a single Participant Field are calculated according to Equation 19.

Equation 18: Total Project Emissions

$$PE_y = \sum_{p}^{P} PE_{p,y}$$

WHERE

PE_y	Total project emissions in year y; $MTCO_2e$
$PE_{p,y}$	Total project emissions for Participant Field p in year y; $MTCO_2e$
P	Total Project Participant Fields

Equation 19: Project Emissions

$$PE_{p,y} = C_{AGB,PR_{p,y-1}} - C_{AGB,PR_{p,y}} + C_{BGB,PR_{p,y-1}} - C_{BGB,PR_{p,y}} + E_{PR,N_2O_{p,y}} + E_{FERM_{p,y}} + E_{FF,PRy,p}$$

WHERE

$PE_{p,y}$	Project emissions per participating field **p** in year y
$C_{AGB,PR_{p,y}}$	Carbon stock of above-ground crop biomass for Participant Field p in the project scenario in year y; $MTCO_2e$ (optional)
$C_{BGB,PR_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field p in the project scenario in year y; $MTCO_2e$ (optional)
$E_{PR,N_2O_{p,y}}$	Emissions due to the use of fossil fuels in agricultural management in the project scenario on Participant Field p in year y; $MTCO_2e$
$E_{FERM,p,y}$	Project emissions from livestock – enteric fermentation in Participant Field p in year y; $MTCO_2e$

$E_{FF,PRy,p}$	Emissions due to the use of fossil fuels in project management, fermentation in Participant Field p in year y; $MTCO_2e$ (optional)

6.2.1 Accounting Project Emissions from Aboveground Biomass (Woody and Non-woody)

This pool is optional. If included, woody biomass is non-tree. If included, projects must account for these emissions by determining initial above ground carbon stocks for each biomass type using one of the following methods:

- Models meeting the criteria in Section 5 Use of Models for GHG Estimation.[43]
- Direct field measurements of $C_{AGB_{b,y=0}}$ or $DM_{b,y=0}$ and CF_b (Equation 21) for each biomass type, b, in a year where growing season precipitation is within 30% of average annual growing season precipitation or averaged over three years.[44]
- Remote sensing of $C_{AGB_{b,y=0}}$ or $DM_{b,y=0}$ and CF_b (Equation 21) for each biomass type, b, in a year where growing season precipitation is within 30% of average annual growing season precipitation or averaged over three years. Remote sensing data should be calibrated to the Project Area with field samples.[45]
- Data as available from government agency or University extension office for $DM_{b,y=0}$ and CF_b

This methodology assumes all aboveground biomass from these pools is lost following conversion to Cropland. Typical aboveground biomass may include grasses, leguminous and non-leguminous forbs, shrubs and trees. Above-ground biomass is highly variable in rangeland systems, both geographically and temporally, and is highly dependent upon precipitation. A conservative estimate of peak annual above-ground biomass (excluding trees) shall therefore be assumed to remain at a steady state for the duration of the Project Crediting Period.

Equation 20: Project Aboveground Biomass

$$C_{AGB,PR_{p,y}} = \sum_{b}^{B} C_{AGB_{b,y=0}}$$

[43] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[44] Conducted for project or available in peer reviewed literature.

[45] Conducted for project or available in peer reviewed literature.

WHERE

$C_{AGB,PR_{p,y}}$	Carbon stock of above-ground biomass for Participant Field p in the project scenario in year y
$C_{AGB_{b,y=0}}$	Initial (year y=0) carbon stock of above-ground biomass for biomass type b; $MTCO_2e$

Equation 21: Initial Project Aboveground Biomass

$$C_{AGB_{b,y=0}} = DM_{b,y=0} \times CF_b \times \frac{44}{12} \times A_b$$

WHERE

$C_{AGB_{b,y=0}}$	Initial (year y=0) carbon stock of above-ground biomass for biomass type b; $MTCO_2e$
$DM_{b,y=0}$	Dry matter for biomass type b at project initiation (year $y=0$); MT dry matter ha^{-1}
CF_b	Carbon fraction of dry matter for biomass type b; MT C (MT dry matter)$^{-1}$
A_b	Area of biomass type b; hectares
$\frac{44}{12}$	Ratio of molar mass of CO_2 to C

6.2.2 Accounting Project Emissions from Belowground Biomass

This pool is optional. If included, projects must account for these emissions by determining initial below ground carbon stocks for each biomass type using one of the following methods:

- Models meeting the criteria in Section 5 Use of Models for GHG Estimation[46]

[46] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB,BL_{p,y}}$.

- $C_{AGB,PR_{p,y}}$ (Equation 22) and appropriate root-to-shoot ratios for crop and woody and non-woody components

Equation 22: Project Belowground Biomass

$$C_{BGB,PR_{p,y}} = \sum_{b}^{B} R_b \times C_{AGB_{b,y=0}}$$

WHERE

$C_{BGB,PR_{p,y}}$	Carbon stock of below-ground biomass for Participant Field p in the project scenario in year y; $MTCO_2e$
B	Total number of biomass types
R_b	Root carbon-to-shoot carbon ratio of biomass type b; default value 4.2 for temperate Grassland, 4.5 for cool temperate Grassland, and 1.8 for Shrubland (Mokany et al. 2006); d.u.[47,48]
$C_{AGB_{b,y=0}}$	Initial (year $y=0$) carbon stock in above-ground biomass of biomass type b; $MTCO_2e$

As stated in Section 6.2.1, above-ground biomass stocks are assumed to remain in steady-state throughout the project duration; the corresponding carbon stock change in below-ground biomass pools is therefore also assumed to be zero over the project life. Although management activities in the project scenario, such as grazing, haying or prescribed fires have been demonstrated to stimulate below-ground biomass growth, these potential gains are conservatively excluded.

[47] Project Proponents can replace the default rate with a site-specific value or more recent value from peer reviewed literature.

[48] In Grasslands, a global database finds that carbon concentration in roots and shoots are relatively equivalent across sites (median 44% in leaves and 43% in roots; Craine et al. 2005). Therefore, root-to-shoot ratios are equivalent to the root carbon-to-shoot carbon ratios in Grasslands.

6.2.3 Accounting Project Emissions from Soil Organic Carbon

SOC stocks are conservatively assumed to be in a steady state from the date of recording of the easement, such that soil organic carbon stocks in the project scenario are fixed over the project life i.e. do not increase. Because there is no change in SOC during year y in the project scenario, this term is not included in the total project emissions for year y, Equation 19.

6.2.4 Accounting Project Emissions from Soil N_2O

Direct soil N_2O emissions in the project scenario result from nitrogen fertilizer application, both synthetic and organic. Quantification of indirect N_2O emissions from nitrogen fertilizer application is highly uncertain. GHG benefits from this pool cannot be assured to be real and are therefore conservatively excluded from both the baseline and project scenario.[49]

$E_{PR,N_2O_{p,y}}$ may be determined by:

- Models meeting the criteria in Section 5 Use of Models for GHG Estimation.[50]
- Equations 23- 27.[51]

Equation 23: Project N_2O Emissions

$$\mathbf{E_{PR,N_2O_{p,y}} = E_{PR,N_2O,direct_{p,y}} = [\left(F_{PR,SN_{p,y}} + F_{PR,ON_{p,y}}\right) \times EF_N + F_{PRP,p,y} \times EF_{MNR}] \times \frac{44}{28} \times GWP_{N_2O}}$$

WHERE

$E_{PR,N_2O_{p,y}}$	Total N_2O emissions from Participant Field p in year y; $MTCO_2e$
$E_{PR,N_2O,direct_{p,y}}$	Direct N_2O emissions from the addition of N to Participant Field p in the project scenario for year y; $MTCO_2e$

[49] Nitrogen application is assumed to be higher in the baseline scenario, crop cultivation, relative to the project scenario, grassland with or without grazing.

[50] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[51] CDM A/R Methodological Tool, Estimation of direct nitrous oxide emission from nitrogen fertilization. https://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-07-v1.pdf

$F_{PRP,p,y}$	Mass of manure and urine N deposited by grazing animals on pasture, range and paddock on participant field p, in year y
$F_{PR,SN_{p,y}}$	Mass of synthetic fertilizer nitrogen applied to Participant Field p in the project scenario in year y adjusted for volatilization as NH_3 and NO_X; MT N
$F_{PR,ON_{p,y}}$	Mass of organic N amendments applied to Participant Field p in the project scenario in year y adjusted for volatilization as NH_3 and NO_X; MT N
EF_N	Emission factor for emission from N inputs; MT N_2O-N (MT N input)$^{-1}$
EF_{MNR}	Emission factor for emissions from manure inputs MT N_2O-N (MT N input)$^{-1}$
$\frac{44}{28}$	Ratio of molecular weights of N_2O to N; MT N_2O (MT N)$^{-1}$
GWP_{N_2O}	Global Warming Potential for N_2O[52]

Equation 24: Project Mass of Synthetic Fertilizer Nitrogen

$$F_{PR,SN_{p,y}} = \sum_{j}^{J} M_{PR,SN_{p,j,y}} \times N_{PR,SN_j} \times (1 - Frac_{SN})$$

WHERE

$F_{PR,SN_{p,y}}$	Mass of synthetic N amendments applied to Participant Field p in the project scenario in year y adjusted for volatilization as NH_3 and NO_X; See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{PR,SN_{p,j,y}}$	Mass of synthetic fertilizer type j applied to Participant Field p in year y; MT
N_{PR,SN_j}	Nitrogen content of synthetic fertilizer type j; MT-N (MT input)$^{-1}$
$Frac_{SN}$	Fraction of synthetic fertilizer nitrogen that volatilizes as NH_3 and NO_X;
J	Number of synthetic fertilizer types

[52] Project proponents shall refer to the ACR Program Standard for the approved IPCC GWP for nitrous oxide value, which will be updated periodically as new information becomes available.

j	Synthetic fertilizer type

Equation 25: Project Mass of Organic Fertilizer Nitrogen

$$F_{PR,ON_{p,y}} = \sum_{k}^{K} M_{PR,ON_{p,k,y}} \times N_{PR,ON_k} \times (1 - Frac_{ON})$$

WHERE

$F_{PR,ON_{p,y}}$	Mass of organic N amendments applied to Participant Field p in the project scenario in year y adjusted for volatilization as NH_3 and NO_X; See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{PR,ON_{p,k,y}}$	Mass of organic fertilizer type k applied to Participant Field p in year y; MT
N_{PR,ON_k}	Nitrogen content of organic fertilizer type k; MT-N (MT input)$^{-1}$
$Frac_{ON}$	Fraction of organic fertilizer nitrogen that volatilizes as NH_3 and NO_X;
K	Number of organic fertilizer types
k	Organic fertilizer type

Equation 26: Percent Excreta Nitrogen

$$F_{PRPp,y} = \sum_{l}^{L} (P_{p,l} \times Nex_{l,p,y})$$

WHERE

$F_{PRPp,y}$	Percent excreta nitrogen
L	Number of livestock types
l	livestock type
$P_{p,l}$	Population of livestock type l, on participant field p; number of head

$Nex_{l,p,y}$	Annual average N excretion per head of species/category, kg N (animal)$^{-1}$ of livestock type l

Equation 27: Nitrogen Excreta Per Head of Livestock

$$Nex_{l,p,y} = \frac{N_{rate(l)} \times \frac{TAM_l}{1,000} \times GD_{p,l,y}}{1,000}$$

WHERE

$Nex_{l,p,y}$	Nitrogen excreta per head of livestock on participant field p in year y (kg N (animal)-1 (year)-1
$N_{rate(l)}$	N excretion rate; kg N (1,000 kg animal mass)$^{-1}$ day^{-1}
TAM_l	Typical animal mass for livestock category l; kg animal^{-1}
$GD_{p,l,y}$	Grazing days per livestock type l on Participant Field p in year y; grazing days

6.2.5 Accounting Livestock Emissions from Enteric Fermentation

Livestock, such as cattle, bison and sheep, produce CH_4 as a result of enteric fermentation in their rumen. Enteric fermentation emissions vary by species, breed, animal size, feed, environment and management systems (Ominski et al. 2007). Estimates of enteric fermentation can also vary widely depending on the level of specificity of input data and use of defaults (Ominski et al. 2007). It is therefore encouraged that Project Proponents utilize the most representative input data where possible. Further, calves less than 6 months in age are assumed to have zero CH_4 emissions as their diet will be primarily milk (US EPA 2013).

Estimates of enteric CH_4 emissions are restricted to rangeland/pasture manure systems where manure is left unmanaged once deposited by livestock per the Applicability Conditions in Section 1.2. It is recognized that in Grassland ecosystems, the net contribution of livestock in the system may be net GHG sequestration (Liebig et al. 2010). The effects of vegetation stimulation and soil nutrient amendments that grazing and natural manure management, as maintained from pre-project conditions, are assumed to be captured through estimates of soil and biomass carbon pools in the project scenario. Any net sequestration benefits from these activities in the project scenario are conservatively excluded from this methodology but could be eligible for

ERTs under a separate but complimentary Grazing Land and Livestock Management methodology. Manure deposited by livestock present in the project scenario shall be accounted for in Soil Nitrogen Emissions, Section 6.2.4 Soil Nitrogen Emissions. Project emissions from livestock due to enteric fermentation shall be calculated for each Participant Field in the Project Area according to Equation 28 and 29.

Equation 28: Project Enteric Fermentation

$$E_{Ferm,p,y} = \sum_{li}^{L} P_{p,l} \times EF_{l} \times GD_{p,l,y} \times GWP_{CH_4} \div 1,000$$

WHERE

$E_{Ferm,p,y}$	CH_4 emission from enteric fermentation due to livestock on Participant Field p in year y; $MTCO_2e$
L	Total number of livestock types in project scenario
$P_{p,l}$	Population of livestock type l on Participant Field p; head
$GD_{p,l,y}$	Grazing days per livestock type l on Participant Field p in year y; grazing days
EF_{l}	Enteric CH_4 emission factor for livestock type l; $kgCH_4$ ($head^{-1}$) ($grazing\ day^{-1}$)
GWP_{CH4}	Global warming potential for CH_4 (See ACR Standard)
$1,000$	Conversion kg to MT

Equation 29: Enteric Emission Factor per Head of Livestock

$$EF_{l} = \frac{GE \times \left(\frac{Y_m}{100}\right)}{55.65}$$

WHERE

EF_{l}	Enteric CH_4 emission factor for livestock type l; $kgCH_4$ ($head^{-1}$) ($grazing\ day^{-1}$)
GE	Gross energy intake MJ $head^{-1}$ day^{-1}

Y_m	Methane conversion factor, per cent of gross energy in feed converted to methane. 6.5%; Lambs (<1-year-old): 4.5%; and Mature Sheep: 6.5% Source: Chapter 4, Tables 10.12 and 10.13, IPCC 2006 AFOLU GL
55.65	Energy content of methane; MJ/kg CH_4

6.2.6 Accounting Project Emissions from Fossil Fuels

Accounting for GHG emissions from fossil fuels is optional. Where fossil fuel emissions are accounted for in the baseline, project fossil fuel emissions must also be estimated.

Equation 30: Project Fossil Fuel Emissions

$$E_{FF,PRp,y} = \sum_{v}^{V} \sum_{f}^{F} \left(FF_{PR_{p,v,f,y}} \times EF_f \right)$$

WHERE

$E_{FF,PRp,y}$	Emissions due to the use of fossil fuels in project management, on participant field p in year y; $MTCO_2e$
$FF_{PR,p,v,f,y}$	Consumption of fossil fuel in vehicle/equipment type **v** during year **y** per fuel type **f**; Liters $(yr.)^{-1}$ on participant field p
EF_f	Emission factor for the type of fossil fuel combusted in vehicle or equipment, **v.** See U.S. Energy Information Agency.[53]
v	Type of vehicle/equipment
V	Total number of types of vehicle/equipment used in the project activity
f	Type of fuel
F	Total number of fuel types

[53] https://www.eia.gov/environment/emissions/co2_vol_mass.php

Unlike the baseline scenario, Project Proponents can monitor machinery and equipment use in the project scenario and the quantity of fuel consumed. Where this information is not easily attainable or difficult to estimate, default fuel usage rates from the same sources used to identify fuel usage for the baseline scenario may be used.

6.3 LEAKAGE

Market leakage is the primary source of potential leakage from the avoided conversion of Grassland and Shrubland. Conversion is most likely driven by commodity crops, rather than food crops which would be consumed locally and potentially induce activity shifting leakage. For commodity crops, attempts to estimate activity shifting leakage will double count market leakage. For food crops, the default values provided in this section for market shifting leakage will provide a conservative estimate of activity shifting leakage where it occurs.

Equation 31: Leakage Emissions

$$\mathbf{LE_y = LE_{M,y}}$$

WHERE

LE_y	Leakage factor in year $\mathbf{y}$
$LE_{M,y}$	Market Leakage in year $\mathbf{y}$

6.3.1 Description of Leakage

6.3.1.1 COMMODITY AND FOOD CROP

The crops identified in the baseline analysis shall be assessed for leakage type if they are a food or commodity crop. A commodity crop is traded and consumed in national and/or international markets, traded on a recognized futures exchange, and individual producers are price takers (no ability to affect price). If the majority of crops in a rotation are considered a commodity crop, production is determined to be commodity-dependent, and leakage will therefore be market-driven. Attempts to monitor and estimate activity-shifting leakage in this scenario will lead to double counting of market leakage.

In contrast, non-commodity or food crops are more likely to be purchased or consumed locally or regionally and the displacement of their production will lead to unmet local demand, providing a driver for Activity Shifting leakage. The ability to estimate activity shifting leakage in scenarios

where conversion is driven by non-commodity crops is extremely poor with available data. Estimation errors based on aggregation, sampling error or classification error from remotely sensed images may exceed estimates of annual conversion rates. In these situations, it is considered conservative to use the default market leakage rate to account for all leakage.

6.3.1.2 MARKET LEAKAGE

Avoiding the conversion of Grassland and Shrubland will directly remove arable Cropland that would otherwise enter production. Food demand is relatively inelastic globally, requiring that the foregone production will be made up either through changes at the intensive (fertilizer use, crop yield response) or extensive (indirect land use conversion) margin. Since the commodities being displaced are traded in national and international markets, and production is responsive to numerous dynamic phenomena, estimation of market leakage requires use of detailed economic data and complex general equilibrium models. Completion of these analyses are expected to be beyond the capabilities of most Project Proponents, and therefore a simplified default approach is used to provide a default value of LE_{MY} applicable to avoided conversion to commodity crops in North America that can be used for all Projects using this methodology.

Market leakage is based on the law of supply and demand. Avoided conversion reduces the supply of otherwise arable Cropland, which all else being equal, puts upward pressure on prices, which puts downward pressure on quantity demanded and upward pressure to increase production on non-project lands. The relationship between price and supply and demand are quantified by price elasticities. Price increases can also lead to increased supply through mechanisms other than conversion of additional non-Project lands (i.e. changes at the intensive margin). Price signals inspire farmers to produce more crops on their existing farmland, e.g., by investing in more labor, advanced technology, or inputs (Taheripour 2006). Price signals can also inspire increased investment in yield improvement (Ruttan and Hayami 1984). Thus, avoiding conversion to Cropland is expected to reduce the net amount of land needed for crop production both by increasing yields on existing farmland and by decreasing the quantity of demand. Methods based only on short-run price elasticities generally capture decreased demand but may not capture these additional mechanisms that contribute to meeting demand without requiring Cropland expansion. Therefore, methods based only on price elasticities will tend to overestimate leakage, making them conservative from the standpoint of calculating offsets generated by a project.

The default leakage value is derived from Equation 32, which is derived from Murray, McCarl and Lee (2004).

Equation 32: Market Leakage

$$LE_{M,y} = \frac{E_S}{E_S - E_D}$$

WHERE

$LE_{M,y}$	Market leakage in year **y**; (0-1.0)
E_S	Price elasticity of supply
E_D	Price elasticity of demand

Note that Price elasticity of demand (E_D) is generally a negative number (demand goes down as price goes up) and Price elasticity of supply (E_S) is generally a positive number (supply goes up as price goes up), so market leakage will be a percentage that ranges from 0 to 100.

Elasticities may be obtained from the Food and Agriculture Policy Research Institute (FAPRI) Elasticity Database[54,55] as well as peer reviewed literature and state government reports.

To obtain a default value that can be reliably used in the United States, we considered a range of approaches to estimating leakage and used the most conservative result. Several researchers have used estimates of leakage associated with the USDA Conservation Reserve Program (CRP). The retirement of land from crop production as in the Conservation Reserve Program should have similar or larger leakage effects as an avoided conversion project that keeps land out of crop production. Both approaches preclude marginal Cropland from entering crop production. One might expect CRP to have greater leakage because of both the large scale of land retirement and because CRP typically removes land entirely from all productive uses, although some emergency haying and grazing is allowed, whereas, conservation through a carbon offset program such as this one still allow grazing and livestock production.

[54] The USDA Commodity and Food Elasticity Database is no longer being updated (https://www.ers.usda.gov/data-products/commodity-and-food-elasticities/).

[55] http://www.fapri.iastate.edu/tools/elasticity.aspx

Table 3: Literature Values for Leakage Associated with the USDA CRP

SOURCE	ESTIMATE OF MARKET EFFECTS LEAKAGE	APPROACH
Taheripour, (2006)	≤20%	General equilibrium model of CRP leakage.
Wu (2000)	20%	Statistical estimate of leakage based on empirical land use data associated with the implementation of the CRP.
Barr et al. (2011)	<20%	Price elasticity of Cropland supply was found to be 0.029. When combined with reasonable estimates of price elasticity of demand, this consistently results in leakage estimates of <20%.
Murray et al. (2007)	0-20%	Plausible leakage discount for Cropland retirement based on previous literature.

A peer reviewed paper studied actual responses of U.S. land area to changes in prices and found that the price elasticity of Cropland area in the United States is very low (0.029 was the highest of several estimates in the paper) (Barr et al. 2011). Unfortunately, this paper does not provide a comparable estimate for price elasticity of demand. In the absence of a definitive estimate of demand, we are able to show that any reasonable estimate of the price elasticity of demand yields a leakage estimate that is no greater than 20% when paired with Barr et al.'s estimate for price elasticity of supply. Any estimate of the price elasticity of demand that is less than -0.116 would result in leakage of 20% or lower. In drafting of version 1.0 of this methodology, 241 estimates were obtained from the USDA ERS database on own-price demand elasticities for commodities relevant to the United States (corn, soy, legume, grain, cereal, oil, food) for the period prior to 2014. The mean demand elasticity was -0.44, and more than 90% of all values were less than -0.116.

Therefore, a conservative default value of 20% market leakage may be used for avoided conversion of Grasslands or Shrublands to commodity crops in the United States.

6.3.2 Quantification of Leakage Deduction

Equation 33: Leakage Deduction

$$LD_y = LE_y \times \sum_{p}^{P} \left(C_{AGB,BL_{p,y-1}} - C_{AGB,BL_{p,y}} + C_{BGB,BL_{p,y-1}} - C_{BGB,BL_{p,y}} + C_{SOC,BL_{p,y-1}} - C_{SOC,BL_{p,y}} \right)$$

WHERE

LD_y	Leakage deduction in year y
LE_y	Leakage in year y, $MTCO_2e$ (Equation 31)
$C_{AGB,BL_{p,y}}$	Carbon stock of aboveground biomass in Participant Field p in year y in the baseline scenario; $MTCO_2e$. (Equation 3, optional pool)
$C_{BGB,BL_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field p in the baseline scenario in year y; $MTCO_2e$. (Equation 7, optional pool)
$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field p in the baseline scenario in year y; $MTCO_2e$. (Equation 10)

6.4 NET GHG EMISSIONS

Equation 34: Net Emission Reductions

$$ER_y = BE_y - PE_y - NP_y - LD_y$$

WHERE

ER_y	Net GHG emissions reductions and/or removals in year y, $MTCO_2e$
BE_y	Baseline emissions in year y, (Equation 1) $MTCO_2e$
PE_y	Project emissions in year y, (Equation 16) $MTCO_2e$
NP_y	Non-Permanence deduction in year y, (Equation 35) $MTCO_2e$
LD_y	Leakage deduction for year y, (Equation 31) $MTCO_2e$

Where $BEy < PEy$, no ERTs shall be issued for that year.

Equation 35: Non-Permanence Deduction

$$NP_y = BF_y \times \sum_{p}^{P} \left(C_{AGB,BL_{p,y-1}} - C_{AGB,BL_{p,y}} + C_{BGB,BL_{p,y-1}} - C_{BGB,BL_{p,y}} + C_{SOC,BL_{p,y-1}} - C_{SOC,BL_{p,y}} \right)$$

WHERE

NP_y	Non-Permanence deduction for year y
BF_y	Non-Permanence buffer in year y, result of project analysis using the latest version of the ACR Tool for Risk Analysis and Buffer Determination to determine the overall project risk rating, applied as BFy.[56]
$C_{AGB,BL_{p,y}}$	Carbon stock of aboveground biomass in Participant Field p in year y in the baseline scenario; $MTCO_2e$ (Equation 3, optional pool)
$C_{BGB,BL_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field p in the baseline scenario in year y; $MTCO_2e$ (Equation 7, optional pool)
$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field p in the baseline scenario in year y; $MTCO_2e$ (Equation 10)

6.5 UNCERTAINTY

Estimation of uncertainty is required for each baseline and project carbon pool and GHG sources. When sampling is conducted, and the 90% confidence limit (high or low) is greater than 10% of the mean value, the confidence limit (resulting in the lowest ERT value) shall be used rather than the sampled mean to ensure conservativeness. Uncertainty estimates or lower bounds are required for default values (such as those by the IPCC), estimates from peer-reviewed literature, and direct measurements or empirical relationships based on measurements. They should be directly estimated per general requirements in the ACR Standard. Where process models are used to estimate pools and sources, key sources of uncertainty in model parameters and inputs should be used to model uncertainty.[57] Models approved for use by ACR

[56] As described in the most recent version of the ACR Standard, the Project Proponent shall use the ACR Tool for Risk Analysis and Buffer Determination.

[57] Where a range of plausible uncertainty values are available for a parameter or input, Project Proponents shall select the most conservative value so as not to overestimate project emission reductions.

with this methodology must meet all criteria for process based biogeochemical models in the ACR Standard. When the DAYCENT model is used, an uncertainty deduction factor of 10% must be subtracted from the difference between baseline and project SOC.[58]

6.6 PERMANENCE AND REVERSALS

Carbon offsets generated through the sequestration of carbon in soil or biomass are inherently at some risk of reversal or termination. Reversals can be unintentional or intentional. Internal risk factors include project management, financial viability, opportunity costs and project longevity. External risk factors include factors related to easement violations and natural risks including fire, flood, and extreme weather events. See specific instructions for agriculture/grassland projects within the ACR Risk Assessment Tool. The risk assessment, overall risk rating, and proposed mitigation or buffer contribution shall be included in the GHG Project Plan.

Per the Buffer Pool Terms and Conditions (see the ACR Standard) sequestration projects will terminate automatically if a Reversal causes project stocks to decrease below baseline levels prior to the end of the Minimum Project Term.

6.6.1 Assessment of Risk

To assess the risk of reversal or termination, the Project Proponents shall conduct a risk assessment addressing internal, external and natural risks using the most recently approved ACR Risk Assessment Tool.[59]

6.6.2 Mitigation of Risk

While prescribed burns are allowed under this Methodology, fire could have negative ecological impacts and reduce aboveground biomass in shrublands in addition to potentially reversing carbon storage resulting from the project when best practices for prescribed burns are not followed. Project Proponents shall know and follow best management practices for use of fire for the vegetation type and region.

An alternative value may be used if Project Proponents can justify why the selected parameter or input value is more appropriate than the most conservatively available value, with the justification transparent in the GHG Project Plan Document and/or Monitoring Report.

[58] Based on Ogle et al. 2007 for CRP lands

[59] http://americancarbonregistry.org/carbon-accounting/tools-templates/acr-risk-tool-v1-0.pdf

6.6.3 Buffer Pool Contributions

ACR's Risk Assessment Tool produces a total risk rating for the project which equals the percentage of offsets that must be deposited in the ACR buffer pool to compensate for reversal or termination (unless another ACR approved risk mitigation mechanism is used in lieu of buffer contribution). The risk assessment, overall risk rating, and proposed mitigation or buffer contribution shall be included in the GHG Project Plan.

7 MONITORING AND DATA COLLECTION

Each project shall include a GHG project plan sufficiently meeting the requirements of the ACR Standard. The plan shall describe the collection of all data required to be monitored and, in a manner, which meets the requirements for accuracy and precision of this Methodology. Project Proponents shall use the template for GHG project plans available at www.americancarbonregistry.org. Additionally, projects are required to submit a GHG monitoring report for each reporting period. Project Proponents shall use the template for GHG monitoring reports available at http://americancarbonregistry.org/carbon-accounting/tools-templates.

7.1 THE GHG PROJECT PLAN

Requirements for GHG Project Plans for all ACR projects are listed in the ACR Standard. See sections 7.2 and 7.3 for additional GHG Project Plan requirements, specific to this methodology.

7.2 DATA COLLECTION AND PARAMETERS MONITORED

See Appendix A for a list of parameters available at validation, parameters monitored, and parameters determined from equations. Project Proponents are strongly encouraged to maintain area-based parameters in per Hectare (or per acre) units as well per field p, to assist validation and verification events.

7.2.1 Description of the Monitoring Plan

The Monitoring Plan is developed at time of validation, contained in the GHG Project Plan and submitted at each verification event. In addition to the parameters listed in Appendix A the monitoring plan must also include:

- Baseline Crop Management Scenario (Section 3.1.2); updated at minimum every 5 years
- Spatially explicit shapefiles for project boundaries (Section 2.1.2)
- Conversion Agents

- Livestock presence, average annual AUMs of grazing and average annual forage availability in AUMs within the Project Area and the dates of grazing activity[60]
- Cover of Grassland versus Shrubland in Project Area
- Any effects of disturbance, especially of burning (wildfire or prescribed), on aboveground shrub biomass.

The Monitoring Report shall further describe the following:

- Monitoring tasks included or required as part of the LCA and responsible party
- Frequency of monitoring tasks and reporting
- Measurement procedures and frequency of collection (if applicable)
- Biogeochemical model parameter definitions[61]
- Quality Assurance/Quality Control measures
- Archiving measures
- Responsibilities, roles and qualifications of monitoring team
- Any due diligence for boundaries in the LCA

7.2.2 Sampling Design

Where Project Proponents elect to employ direct measurements, the Monitoring Plan in the GHG Project Plan Document shall specify the sampling design, sample size, plot size and determination of plot locations. All sampling must be carried out such that a 90% Confidence Interval does not exceed 10% of the mean. Where uncertainty exceeds 10% of the mean, estimated GHG benefits or values must be discounted by using the boundary of the confidence interval. All measurements will be conducted according to approved sampling standards and subject to Quality Assurance/Quality Control measures, as specified in the Monitoring Plan.

[60] A Grazing Management Plan, when available, meets this monitoring requirement. Grazing practices, including intensity, shall be consistent with the conservation goals set forth in the easement.

[61] Necessary environmental parameters for use in biogeochemical modeling and determination of ex post pools and sources estimated with a biogeochemical model are to be recorded. Sources for such variables may include national databases, or published data with the selection and collection of such data provided in a transparent manner in the Monitoring Report for easy verification and replication. Where meteorological data is collected from a regional meteorology station in the Project Region, information from the nearest station is advised, preferably within 100km of the Participant Field. Where the Project Area exceeds a 100km radius, a single or averaged set of meteorological data may be utilized.

7.3 DATA ARCHIVING

The VVB shall retain reports, measurements and other project related documents, including documentation of LU/LC conversion, per requirements in the ACR Standard. Where soil samples are collected, these shall be maintained by the project developer until at least the next scheduled verification event, i.e. 5 years. Soil and other durable samples shall be stored in an air-dry condition in a cool, dry location.

8 VALIDATION AND VERIFICATION

8.1 ACR VV STANDARD AND DEVIATIONS

Aspects of the avoided conversion project type are unique such that certain validation and verification procedures are allowed that supersede the ACR Verification and Validation Standard.[62] Specific instances where this methodology supersedes requirements in the ACR Validation and Verification Standard are described below. Unless otherwise stated, the requirements in the most recent version of the ACR Validation and Verification Standard apply to all projects.

8.1.1 Listing Requirements

Submittal of a full GHG Project Plan is not required at listing for this project type. Project Proponents can submit basic project information and the Statement of Intent or GHG ownership agreement and estimated future properties (if PDA) within ± 12 months of date of recording of the LCA. A complete GHG Project Plan can be submitted up until the time of validation.[63]

8.1.2 Site Visits

Site-visits are not required at validation nor at subsequent verifications for this project type, provided the verifier can reach a reasonable level of assurance via review of required documents and supplemental material (e.g. images, on-going monitoring reports as required as part of the LCA, telephone interviews, including those with the responsible entity for the LCA, remote sensing, third party datasets etc.). The verifier has discretion to request a site-visit at the following times in the project life cycle IF he/she determines that a reasonable level of assurance is unattainable without a site visit: at validation, if a reversal occurs, if LCA or regulatory infraction occurs, or change in VVB.

At a minimum, the following must be included in a remote verification:

[62] These include: 1) the baseline scenario is a counter factual scenario and cannot be monitored, rather the baseline assumptions are justified ex ante 2) the project activity requires a qualified LCA be recorded, which in and of itself includes due diligence prior to recording and on-going monitoring and reporting and 3) LCAs are complex legal agreements that vary geographically and upon the nature of the organizations entering into the agreement; it is difficult to predict with accuracy when an LCA will be completed and recorded and thus to know in advance the official project start date.

[63] Per the ACR Standard, AFOLU projects must COMPLETE validation within 3 years of the start date of the project; i.e. the date of qualified LCA recording.

- Spatially-explicit boundary shape file of Project Region, Project Area, and Participant Fields, including delineation of any wetlands, building envelopes, cultivated areas, gravel pits, or other acres not governed by a sod-busting/no-conversion clause. Participant Field boundaries will not be made public.
- Spatially-explicit boundary shapefiles of the area covered by the qualified LCA.
- Copy of the recorded Land Conservation Agreement(s)/Easement(s) that encompass all Participant Fields.
- Record of due diligence for accurate boundary definition prior to LCA recording.
- Links to recent LANDSAT imagery of the project area or time stamped LANDSAT image files.
- Record or image of the Participant Fields being Grassland or Shrubland at 10 years prior to start date.
- Monitoring Plan for the qualified LCA.
- Evidence of ownership/right-to the GHG offsets for Project Participant on all Participant Fields for the crediting period being verified.
- GHG Project Plan and associated components. This includes documentation on how any models were parameterized and a detailed Monitoring Plan.
- GHG Quantification documents with modeling output, assumptions, and net GHG calculations.
- If applicable, an electronic copy of the appraisal and valid appraiser's license.

Annual easement monitoring reports are sufficient for demonstrating that the land has not been converted or undergone significant changes and is being managed in a way consistent with the protected conservation values. If an easement violation occurs, the registry must be informed in accordance with ACR's Standard, and it must be referenced in the project plan being verified, including any remediation steps taken.

8.1.3 Requirements for PDA Projects

Requirements for PDA projects as defined in the ACR Standard apply. Regarding site visits, this methodology supersedes requirements in the ACR Standard (See Section 8.1.2).

8.1.4 Significant Changes to a Project

If a significant or a substantial change occurs to the project after validation and/or initial verification, a site visit may be required either by the verifier or ACR, before the next issuance of ERTs. Examples of significant changes include:

- Partial reversal of credits issued to date for a specific parcel and it intends to continue to participate in the project.
- Unintentional reversals resulting from extreme weather events that cause a change to the baseline soil carbon stocks.
- If a parcel is considered a full reversal and it's intentional.
- Material regulatory violations that exclude parcels from future inclusion.

DEFINITIONS

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry Standard apply.

Cropland	A land-use category that includes areas used for the production of crops for harvest on cultivated lands. Cultivated crops include row crops or close grown crops and also hay or pasture in rotation with cultivated crops. Cropland also includes land with alley cropping and windbreaks as well as lands in temporary fallow.[64]
Grassland and Shrubland	A land-use category on which the plant cover is composed principally of grasses, grass-like plants (i.e., sedges and rushes), forbs, or shrubs suitable for grazing and browsing, and includes both pastures and native rangelands. This includes areas where practices such as clearing, burning, chaining, and/or chemicals are applied to maintain the grass vegetation. Savannas, some wetlands and deserts, in addition to tundra are considered Grassland. Woody plant communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also classified as Grassland and Shrubland if they do not meet the criteria for Forest Land. Grassland includes land managed with agroforestry practices such as silvipasture and windbreaks, assuming the stand or woodlot does not meet the criteria for Forest Land.[65]
Forest Land	Land with at least 10 percent cover (or equivalent stocking) by live Trees of any size, including land that formerly had such Tree cover and that will be naturally or artificially regenerated. To qualify, the area must be at least 1 acre in size. Forest Land includes transition zones, such as areas between Forest and non-Forest Lands that have at least 10% cover (or equivalent stocking) with live Trees and forest areas adjacent to urban and built-up lands.[66]

[64] Adapted from: https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/?cid=nrcs143_014127

[65] Adapted from: https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/?cid=nrcs143_014127 Spatial analysis uses the unique definitions of Grassland and Shrubland, respectively, in the NLCD.

[66] https://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

Identified Agent	The known entity that is planning to convert a particular parcel of Grassland or Shrubland to Cropland (e.g., a particular local landowner).
Indirect N_2O Emissions	N_2O emissions that result from microbial nitrification and denitrification of Nitrogen that has first been removed from agricultural soils and animal waste management systems within the project boundary via volatilization, leaching, runoff, or harvest of crop biomass.[67, 68]
Land Conservation Agreement	An easement, covenant, deed restriction, or other legal agreement that may be employed to maintain the project land cover during the Project Crediting Period. The Land Conservation Agreement, as defined in this methodology, does not necessarily contain language pertaining to ownership of carbon or greenhouse gas emissions.
Participant Field	A particular parcel of Grassland or Shrubland where conversion to Cropland is planned by an identified agent or anticipated by an unidentified agent, analogous to the use of project activity in the ACR Standard.
Price Elasticity of Demand	A measure used in economics to show the responsiveness, or elasticity, of the quantity demanded of a good or service to a change in its price, ceteris paribus.
Price Elasticity of Supply	A measure used in economics to show the responsiveness, or elasticity, of the quantity supplied of a good or service to a change in its price.
Project Area	The collection of all participant fields where project activities are implemented.
Project Crediting Period	The length for which project activities are eligible to earn ERTs and the baseline determination remains valid.
Project Participant	A landowner or the manager of a Participant Field.
Project Proponent	An individual or entity that undertakes, develops, and/or owns a project. This may include the project investor, designer, and/or owner of the lands/facilities on which project activities are conducted. The Project

[67] IPCC Good Practice Guidance and Uncertainty Management in National GHG Inventories; https://www.ipcc-nggip.iges.or.jp/public/gp/bgp/4_6_Indirect_N2O_Agriculture.pdf

[68] American Carbon Registry Standard, https://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard/acr-standard-v5-1-july-2018.pdf

	Proponent and landowner/facility owner may be different entities. The Project Proponent is the ACR account holder.
Project Region	The larger region including and encompassing the entire Project Area. The Project Region may be an eco-region or geographic administrative unit.
Soil texture	The proportion of sand, silt and clay sized particles that make up the mineral fraction of the soil. It is a classification instrument used both in the field and laboratory to determine soil classes based on their physical texture.
Stratum	An area of land within which the value of a variable, and the processes leading to change in that variable, are relatively homogenous.
Succession	The process of change in the species structure of an ecological community over time.
Tree	A woody perennial plant, typically large, with a single well-defined stem carrying a more or less definite crown; sometimes defined as attaining a minimum diameter of 3 inches (7.6 cm) and a minimum height of 15 ft (4.6 m) at maturity. For FIA, any plant on the tree list in the current field manual is measured as a tree.[69]
Unidentified Agent	A particular entity that cannot be uniquely identified, but that belongs to a class of known conversion agents (e.g., farm corporations) who plan to convert Grassland or Shrubland to Cropland in the Project Area.

[69] https://www.nrs.fs.fed.us/fia/data-tools/state-reports/glossary/default.asp

APPENDIX A: PARAMETERS

A.1 PARAMETERS DEFINED BY METHODOLOGY EQUATIONS

All parameters in A.1 can also be obtained as outputs from approved biogeochemical models.

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
BE_y	$MTCO_2e$	Baseline emissions in year **y**, all field. **y**=0 at project start date		1
$BE_{p,y}$	$MTCO_2e$	Baseline emissions from participant field **p**, in year **y**		1,2
$C_{AGB,BL_{p,y}}$	$MTCO_2e$	Carbon stock of above-ground biomass for Participant Field **p** in the baseline scenario in year **y**		2,3
$C_{AGB_{b,y=0}}$	$MTCO_2e$	Initial (year **y**=0) carbon stock of above-ground biomass for biomass type **b**		20, 22
$C_{AGB,PR\ p,y}$	$MTCO_2e$	Carbon stock of above-ground biomass for Participant Field **p** in the project scenario in year **y**		4, 19, 21
$C_{AGB_{grass},BL_{p,y}}$	$MTCO_2e$	Carbon stock of (remaining, pre-existing) above ground for Participant Field **p** in year **y** in the baseline scenario, as calculated from Section 6.2.1		3

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$C_{AGB_{crop},BL_{p,y}}$	$MTCO_2e$	Carbon stock of aboveground crop biomass in Participant Field **p** in year **y** in the baseline scenario		5
$C_{AGB_{crop},BL_{b,y}}$	$MTCO_2e$	Carbon stock of aboveground crop biomass in Participant Field **p**, for crop type **b**, in year y in the baseline scenario		5, 6
$C_{BGB,BL_{p,y}}$	$MTCO_2e$	Carbon stock of belowground biomass in Participant Field **p** in year **y** in the baseline scenario		2,7
$C_{BGB_{crop},BL_{p,y}}$	$MTCO_2e$	Carbon stock of belowground crop biomass in Participant Field **p** in year **y** in the baseline scenario		7, 9
$C_{BGB_{grass},BL_{p,y}}$	$MTCO_2e$	Carbon stock of (remaining, pre-existing) belowground biomass from Participant Field **p** in year **y** in the baseline scenario		7, 8
$C_{BGB,PR_{p,y}}$	$MTCO_2e$	Carbon stock of below-ground biomass for Participant Field **p** in the project scenario in year **y**		8, 19, 22
$C_{SOC,BL_{p,y}}$	$MTCO_2e$	Carbon stock of soil organic carbon for Participant Field **p** in the baseline scenario in year **y**		2,10
$F_{BL/PR,ON_{p,y}}$	MT-N	Mass of organic **N** amendments applied to Participant Field **p** in the baseline/project scenario in year **y** adjusted for volatilization as NH_3 and NO_X		12, 14, 23, 25

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$F_{BL/PR,SN_{p,y}}$	MT-N	Mass of synthetic fertilizer nitrogen applied to Participant Field **p** in the baseline/project scenario in year **y** adjusted for volatilization as NH_3 and NO_X		12, 13, 23, 24
$E_{BL/PR,N_2O_{p,y}} = E_{BL/PR,N_2Odirect_{p,y}}$	$MTCO_2e$	Total N_2O emissions from Participant Field **p** in the baseline/project scenario in year **y**. Indirect emissions are conservatively excluded		2, 12, 19, 23
$E_{(BL/PR),FF_{p,y}}$	$MTCO_2e$	Emissions due to the use of fossil fuels in agricultural management in the baseline/project scenario on Participant Field **p** in year **y**		2, 17, 19, 30
$EF_{t,y}$	d.u.	Emission factor for the fraction of soil organic carbon pool remaining **t** years since conversion to Cropland in year **y**		10, 11
$Nex_{l,p,y}$	kg N $(animal)^{-1}$ $(yr.)^{-1}$	Annual average **N** excretion per head of species/category **l**, Participant Field **p** in year **y**		26, 27
$E_{FERM_{p,y}}$	$MTCO_2e$	CH_4 emission from enteric fermentation due to livestock on Participant Field **p** in year **y**		28
PE_y	$MTCO_2e$	Total project emissions in year **y**		18
$PE_{p,y}$	$MTCO_2e$	Total project emissions from participant field **p** in year **y**		18, 19

A.2 PARAMETERS AVAILABLE AT VALIDATION

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
A_b	ha	Area of biomass/crop type **b**	Project Proponent	6, 21
$A_{p,i}$	ha	Area of Participant Field in soil strata **i**	Project Proponent	10
$C_{AGB_{b,y=0}}$	$MTCO_2e$	Initial (year **y**=0) carbon stock of aboveground biomass for Participant Field **p**	Measured, Modeled, values from literature	20, 22
$C_{SOC_{i,y=0}}$	$MTCO_2e\ (ha)^{-1}$	Total initial (year **y**=0) soil organic carbon stock in soil strata **i**, fixed for project duration	Measured, modeled, or literature. Where unavailable, default values from IPCC 2006 AFOLU GL, Table 2.3 may be used.	10
CF_b	MT C $(MT\ dry\ matter)^{-1}$	Carbon fraction of dry matter for biomass type **b**	Literature, Table 11.2 IPCC 2006 GL AFOLU	6, 21
D	years	Transition period for soil organic carbon, time period for transition between equilibrium SOC values, default value of 20	Measured, Modeled, literature, or default value of 20 years (IPCC 2006 AFOLU GL, Ch. 2).	11

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$DM_{b,y=0}$	$MTCO_2e$	Average, annual, dry matter for biomass type **b** at project initiation (year **y**=0)	Measured, Modeled, literature	6, 21
$e^{(-0.77\times(y-t))}$	d.u.	The decay function for aboveground biomass following conversion	Kochsiek et al. 2009	4
$e^{(-1.41\times(y-t))}$	d.u.	The decay function for belowground biomass following conversion	Silver and Miya 2001	8
EF_f	$MTCO_2e$ (liter of fuel)$^{-1}$	Emission factor for the type of fossil fuel combusted in vehicle or equipment	For gasoline EF CO_2e = 8.89 kg CO_2e/gallon. For diesel EF CO_2e = 10.16 kg CO_2e/gallon. Source: EIA	17, 30
EF_l	kg-CH_4 head^{-1} grazing day^{-1}	Enteric CH_4 emission factor for livestock type **l**	Default value for Cattle in Cool Climate Zone: 1; default for Temperate or Warm Climate Zone: 2 Source: Chapter 10, Table 10.14, IPCC 2006 AFOLU GL	28, 29
EF_N	MT-N_2O-N (MT-N input)$^{-1}$	Emission Factor for emission from **N** inputs	0.0254 (2.54%) of applied synthetic fertilizer **N** and 0.02 (2%) of applied organic fertilizer **N** (Davidson, 2009)	12, 23

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
EF_{MNR}	MT-N_2O-N (MT-N input)$^{-1}$	Emission Factor for emission from manure inputs	Literature, Default values may be found Table 11.1, Chapter 11 IPCC 2006 AFOLU GL	23
$FC_{p,y}$	d.u	Proportion of Participant Field **p** that has been converted to Cropland in the baseline scenario for year **y**, d.u.	Project Proponent	10
$FC_{p,t,y}$	d.u.	The cumulative proportion of Participant Field **p** that has been converted to Cropland in year **t**, time of conversion, as of year **y** in the baseline scenario, determined based on rates and extents of conversion	Project Proponent	4, 8
$Frac_{ON}$	kg N volatilized (kg of N applied or deposited)$^{-1}$	Fraction of organic **N** applied to soils that volatilizes as NH_3 and NO_x	Default value of 0.20 Source: Chapter 11, Table 11.3, p. 11.24, IPCC 2006 AFOLU GL	14, 25
$Frac_{SN}$	kg N volatilized (kg of N applied or deposited)$^{-1}$	Fraction of synthetic **N** applied to soils that volatilizes as NH_3 and NO_x	Default value of 0.10 Source: Chapter 11, Table 11.3, p. 11.24, IPCC 2006 AFOLU GL	13, 24

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
GWP_{CH_4}	$MTCO_2e$	Global warming potential for CH_4	See ACR Standard	28
GWP_{N_2O}	$MTCO_2e$	Global warming potential for N_2O	See ACR Standard	12, 23
Y_m	d.u.	Methane conversion factor, per cent of gross energy in feed converted to methane	Suggested Default for Cattle or Buffalo-grazing: 6.5%; Lambs (<1-year-old): 4.5%; and Mature Sheep: 6.5% Source: Chapter 4, Tables 10.12 and 10.13, IPCC 2006 AFOLU GL	29
P		Total number of participant fields, $\mathbf{p}$	Project Proponent	
t	years	Time since conversion of Grassland to Cropland in the baseline scenario	Project Proponent	
R_b	d.u.	Root carbon-to-shoot carbon ratio of (crop) biomass type $\mathbf{b}$; default value 4.2 for temperate grassland, 4.5 for cool temperate grassland and 1.8 for shrubland	Literature, Craine et al. 2005, Mokany et al 2006; or IPCC 2006 AFOLU GL	9, 22

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$\frac{44}{12}$		Ratio of molar mass of CO_2 to C	NA	6, 21
$\frac{44}{28}$		Ratio of molar mass of N_2O to N	NA	12

A.3 PARAMETERS MONITORED

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
B		Total number of crop/biomass types b		
$DM_{BL,b,y}$	MT dry matter $(ha)^{-1}$	Annualized average dry matter in the baseline for crop type b in year y	Harvest Index: ratio of economic product dry mass to plant aboveground dry mass. Alternatively, Values from literature, where none are available use of Harvest Index applied to crop yield guides for the Project Region may be used, or the IPCC default value of 5.0 MT C $(ha)^{-1}$ for annual crops following one year after conversion (IPCC 2006 AFOLU GL, Table 5.9)	6

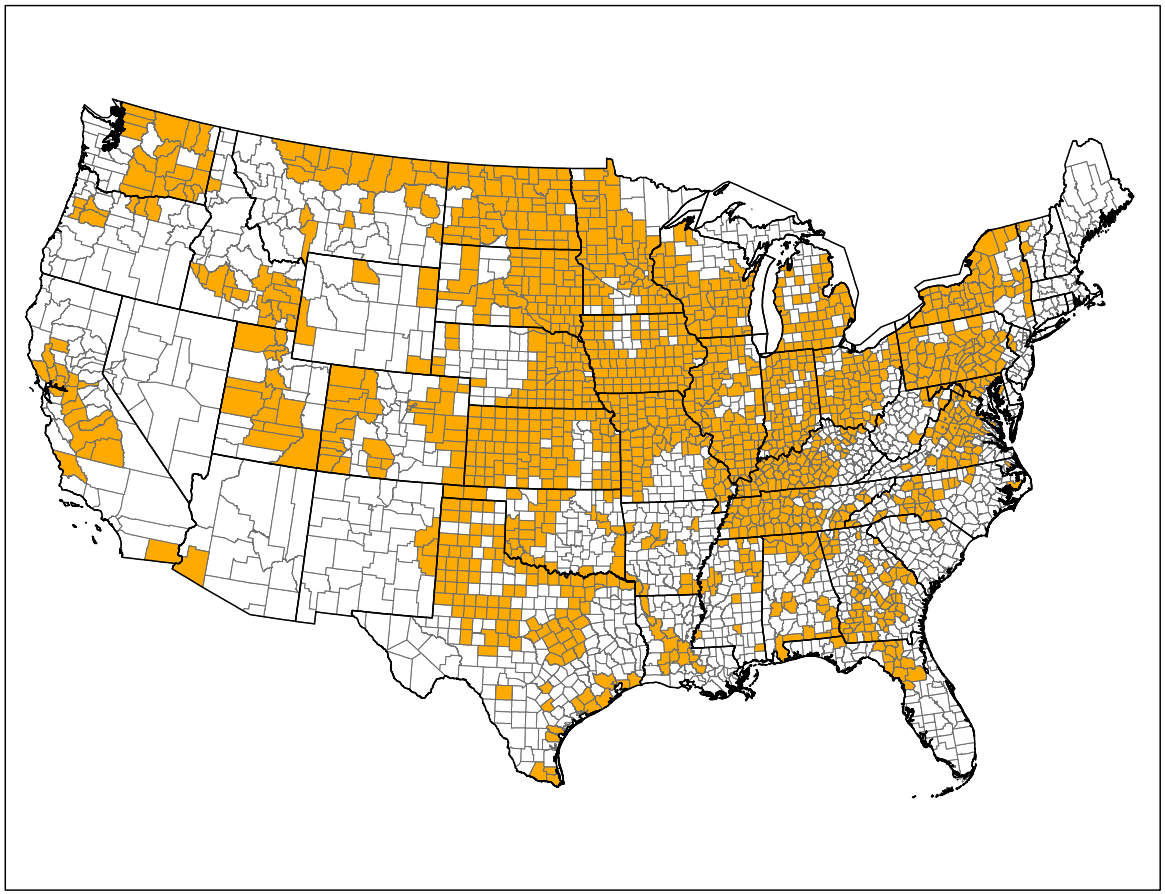
PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$F_{PRP_{p,y}}$	MT-N	Mass of manure and urine **N** deposited by grazing animals on pasture, range and paddock	Producer records, or a university extension or other production report containing grazing animal population multiplied by per animal manure and urine **N** deposition.	23
$FSOC_{LU}$	d.u.	Fraction of soil organic carbon pool remaining after transition period, accounting for land use factors	Literature, model, measured, or IPCC defaults Table 5.5 AFOLU GL 2006	11
$FSOC_{MG}$	d.u.	Fraction of soil organic carbon pool remaining after transition period, accounting for management factors	Literature, model, measured, or IPCC defaults Table 5.5 AFOLU GL 2006	11
$FSOC_{IN}$	d.u.	Fraction of soil organic carbon pool remaining after transition period, accounting for input of organic matter	Literature, model, measured, or IPCC defaults Table 5.5 AFOLU GL 2006	11
$FF_{BL/PR_{p,v,j,y}}$	liters	Volume of fossil fuel consumed in the baseline/project scenario on Participant Field **p** in vehicle/equipment type **v** with fuel type **j** during year **y**	Expert opinion or extension/agency report (baseline) or producer report (project) that contains vehicle/equipment hours and fuel needed per unit of use.	17, 30

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$GD_{p,l,y}$	days	Grazing days per livestock type l on Participant Field p in year y	University extension, producer, or other production report containing average grazing days per livestock type l in the project region.	27, 28
GE	MJ head^{-1} day^{-1}	Gross energy intake	Literature, government reports, or expert opinion.	29
$M_{BL/PR,SN_{p,j,y}}$	MT	Mass of synthetic fertilizer type j applied to Participant Field p in year y	County-level producer surveys conducted by a government agricultural agency(ies) or university extension offices, or the expert opinion of an university extension personnel working in the region and systems of interest, personnel of a governmental agriculture agency field office (e.g., USDA's RMA, FSA, NRCS) with jurisdiction in the Project Region, or Cropland management plans approved by a lending agency.	13, 24
$M_{BL/PR,ON_{p,k,y}}$	MT	Mass of organic N amendment type k applied to Participant Field p in year y	County-level producer surveys conducted by a government agricultural agency(ies) or university extension offices, or the expert opinion of an university extension personnel working in the region and systems of interest, personnel of a governmental agriculture agency field office (e.g., USDA's RMA, FSA,	14, 25

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
			NRCS) with jurisdiction in the Project Region, or Cropland management plans approved by a lending agency.	
$N_{BL/PR,ON_k}$	MT-N (MT input)$^{-1}$	Nitrogen content of organic N amendment type k	Producer of nitrogen if a commercially produced product. Otherwise IPCC defaults or values from the literature.	14, 25
$N_{BL/PR,SN_j}$	MT-N (MT input)$^{-1}$	Nitrogen content of synthetic fertilizer type j	Producer of fertilizer	13, 24
N_{rate_l}	kg N (1,000 kg animal mass)$^{-1}$ day^{-1}	N excretion rate	Default values may be found in Table 10.19, Chapter 10 IPCC 2006 AFOLU GL	27
$P_{p,l}$	number of head	Population of livestock type l	Where the Project Proponent can demonstrate that any positive change in enteric methane would be de minimus then it is not required that livestock populations must be monitored at the level of the Participant Field. This could be done by identifying the maximum stocking rate observed in the Project Region and calculating the difference in enteric methane emission between the baseline and maximum stocking rate.	26, 28

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
TAM_l	kg animal^{-1}	Typical animal mass for live-stock category **l**	Literature, government reports, or expert opinion.	27
L		Total number of livestock types in project scenario	Project Proponent	26, 28
J		Total number of synthetic **N** inputs, **j**	Project Proponent	13, 24
K		Total number of organic **N** amendments, **k**	Project Proponent	14, 25
V		Total number of vehicles, **v**	Project Proponent	17, 30
F		Total number of fossil fuels, **f**	Project Proponent	17, 30

APPENDIX B: COUNTY MAP FOR UNIDENTIFIED AGENT OF CONVERSION



Project fields/parcels located in the counties highlighted in orange have a baseline scenario of cropland for unidentified agents of conversion and surpass the practice-based performance standard for demonstrating additionality. Project fields/parcels in white counties must determine the baseline land-use scenario and demonstrate additionality according to sections 3.1.1.2 and 3.2.2.2 respectively.

STATE	COUNTY
AL	Baldwin County
	Barbour County
	Bullock County
	Calhoun County
	Cherokee County
	Colbert County
	Covington County
	Cullman County
	Dallas County
	DeKalb County
	Escambia County
	Etowah County
	Franklin County
	Geneva County
	Henry County
	Houston County
	Jackson County
	Lauderdale County
	Lawrence County
	Limestone County
	Macon County
	Madison County
	Marengo County
	Marshall County
	Morgan County
	Perry County
	Talladega County
AR	Ashley County
	Chicot County
	Conway County
	Crawford County
	Drew County
	Jackson County
	Lafayette County
	Little River County
	Lonoke County
	Miller County
	Perry County
	Pope County
	Yell County
AZ	Yuma County
CA	Amador County
	Contra Costa County
	Fresno County
	Glenn County
	Imperial County
	Kings County
	Lake County
	Madera County
	Merced County
	Napa County
	Sacramento County
	San Joaquin County
	San Luis Obispo County
	Solano County
	Sonoma County
	Stanislaus County
	Tulare County
	Yolo County
CO	Adams County
	Alamosa County
	Arapahoe County
	Baca County
	Cheyenne County
	Conejos County
	Delta County
	Denver County
	Dolores County
	Eagle County
	Elbert County
	Garfield County
	Kiowa County
	Kit Carson County
	La Plata County
	Lincoln County
	Logan County
	Mesa County
	Moffat County
	Montezuma County
	Montrose County
	Morgan County
	Phillips County
	Pitkin County
	Prowers County
	Rio Blanco County
	Rio Grande County
	Routt County
	Saguache County
	San Miguel County
	Washington County
FL	Alachua County
	Citrus County
	Columbia County
	Dixie County
	Gilchrist County
	Hamilton County
	Jackson County
	Lafayette County
	Levy County
	Madison County
	Marion County
	Suwannee County
GA	Appling County
	Atkinson County
	Bacon County

STATE	COUNTY
	Baker County
	Bartow County
	Berrien County
	Bleckley County
	Brooks County
	Burke County
	Calhoun County
	Chattooga County
	Coffee County
	Colquitt County
	Crawford County
	Crisp County
	Decatur County
	Dodge County
	Dougherty County
	Early County
	Floyd County
	Gordon County
	Hart County
	Houston County
	Irwin County
	Jeff Davis County
	Jefferson County
	Jenkins County
	Johnson County
	Lamar County
	Lanier County
	Lee County
	Macon County
	Miller County
	Mitchell County
	Monroe County
	Montgomery County
	Morgan County
	Murray County
	Peach County
	Pierce County
	Polk County
	Putnam County
	Richmond County
	Screven County
	Seminole County
	Spalding County
	Sumter County
	Taylor County
	Telfair County
	Terrell County
	Thomas County
	Toombs County
	Treutlen County
	Walker County
	Walton County
	Warren County
	Washington County
	Wheeler County
	White County
	Worth County
IA	Adair County
	Adams County
	Allamakee County
	Appanoose County
	Audubon County
	Benton County
	Black Hawk County
	Butler County
	Carroll County
	Cass County
	Cedar County
	Cherokee County
	Chickasaw County
	Clarke County
	Clay County
	Clayton County
	Clinton County
	Crawford County
	Dallas County
	Davis County
	Decatur County
	Delaware County
	Des Moines County
	Dickinson County
	Dubuque County
	Emmet County
	Fayette County
	Floyd County
	Franklin County
	Fremont County
	Greene County
	Grundy County
	Guthrie County
	Hancock County
	Hardin County
	Harrison County
	Henry County
	Howard County
	Ida County
	Iowa County
	Jackson County
	Jasper County
	Jefferson County
	Johnson County
	Jones County
	Keokuk County
	Lee County
	Linn County
	Louisa County
	Lucas County
	Lyon County

STATE	COUNTY
	Madison County
	Mahaska County
	Marion County
	Marshall County
	Mills County
	Mitchell County
	Monona County
	Monroe County
	Montgomery County
	Muscatine County
	O'Brien County
	Osceola County
	Page County
	Plymouth County
	Polk County
	Pottawattamie County
	Poweshiek County
	Ringgold County
	Sac County
	Shelby County
	Sioux County
	Story County
	Tama County
	Taylor County
	Union County
	Van Buren County
	Wapello County
	Warren County
	Washington County
	Wayne County
	Winnebago County
	Winneshiek County
	Woodbury County
	Wright County
ID	Ada County
	Bannock County
	Bear Lake County
	Bingham County
	Bonneville County
	Butte County
	Camas County
	Canyon County
	Caribou County
	Elmore County
	Gooding County
	Jefferson County
	Latah County
	Lincoln County
	Madison County
	Oneida County
	Power County
IL	Adams County
	Alexander County
	Bond County
	Boone County
	Brown County
	Bureau County
	Calhoun County
	Carroll County
	Cass County
	Christian County
	Clay County
	Clinton County
	Coles County
	Crawford County
	Cumberland County
	DeKalb County
	Douglas County
	Edgar County
	Edwards County
	Effingham County
	Fayette County
	Ford County
	Franklin County
	Fulton County
	Gallatin County
	Greene County
	Hamilton County
	Hancock County
	Hardin County
	Henderson County
	Henry County
	Jackson County
	Jasper County
	Jefferson County
	Jersey County
	Jo Daviess County
	Johnson County
	Kane County
	Kankakee County
	Kendall County
	Knox County
	Lawrence County
	Lee County
	Livingston County
	Macoupin County
	Madison County
	Marion County
	Marshall County
	Mason County
	Massac County
	McDonough County
	McHenry County
	McLean County
	Menard County
	Mercer County
	Monroe County
	Montgomery County

STATE	COUNTY
	Morgan County
	Ogle County
	Peoria County
	Perry County
	Pike County
	Pope County
	Pulaski County
	Putnam County
	Randolph County
	Richland County
	Rock Island County
	Saint Clair County
	Saline County
	Schuyler County
	Scott County
	Shelby County
	Stark County
	Stephenson County
	Tazewell County
	Union County
	Vermilion County
	Wabash County
	Warren County
	Washington County
	Wayne County
	White County
	Whiteside County
	Will County
	Williamson County
	Winnebago County
IN	Adams County
	Allen County
	Benton County
	Blackford County
	Boone County
	Brown County

STATE	COUNTY
	Carroll County
	Cass County
	Clark County
	Clay County
	Crawford County
	Daviess County
	Decatur County
	DeKalb County
	Delaware County
	Dubois County
	Elkhart County
	Fayette County
	Floyd County
	Fountain County
	Franklin County
	Fulton County
	Gibson County
	Greene County
	Hamilton County
	Harrison County
	Hendricks County
	Henry County
	Huntington County
	Jackson County
	Jasper County
	Jay County
	Jefferson County
	Jennings County
	Knox County
	Kosciusko County
	LaGrange County
	LaPorte County
	Lawrence County
	Madison County
	Marshall County
	Martin County

STATE	COUNTY
	Miami County
	Monroe County
	Montgomery County
	Morgan County
	Newton County
	Noble County
	Orange County
	Owen County
	Perry County
	Pike County
	Porter County
	Pulaski County
	Putnam County
	Randolph County
	Ripley County
	Rush County
	Saint Joseph County
	Scott County
	Spencer County
	Starke County
	Steuben County
	Tippecanoe County
	Union County
	Vermillion County
	Vigo County
	Warren County
	Warrick County
	Washington County
	Wayne County
	White County
	Whitley County
KS	Allen County
	Atchison County
	Barton County
	Bourbon County
	Brown County

STATE	COUNTY
	Butler County
	Cherokee County
	Cheyenne County
	Clay County
	Cloud County
	Comanche County
	Crawford County
	Decatur County
	Dickinson County
	Doniphan County
	Douglas County
	Edwards County
	Ellis County
	Finney County
	Ford County
	Franklin County
	Gove County
	Graham County
	Grant County
	Gray County
	Greeley County
	Hamilton County
	Harper County
	Harvey County
	Haskell County
	Hodgeman County
	Jackson County
	Jefferson County
	Jewell County
	Johnson County
	Kearny County
	Kingman County
	Kiowa County
	Labette County
	Lane County
	Leavenworth County

STATE	COUNTY
	Lincoln County
	Linn County
	Logan County
	Marion County
	Marshall County
	McPherson County
	Meade County
	Miami County
	Mitchell County
	Montgomery County
	Morton County
	Nemaha County
	Neosho County
	Ness County
	Norton County
	Osage County
	Osborne County
	Ottawa County
	Pawnee County
	Phillips County
	Pratt County
	Rawlins County
	Reno County
	Republic County
	Rice County
	Rooks County
	Rush County
	Russell County
	Saline County
	Scott County
	Sedgwick County
	Seward County
	Shawnee County
	Sheridan County
	Sherman County
	Smith County

STATE	COUNTY
	Stafford County
	Stanton County
	Stevens County
	Sumner County
	Thomas County
	Trego County
	Wallace County
	Washington County
	Wichita County
	Wilson County
KY	Adair County
	Allen County
	Ballard County
	Barren County
	Bath County
	Bourbon County
	Boyle County
	Breckinridge County
	Bullitt County
	Butler County
	Caldwell County
	Calloway County
	Carlisle County
	Carroll County
	Casey County
	Christian County
	Clark County
	Clinton County
	Crittenden County
	Cumberland County
	Daviess County
	Edmonson County
	Estill County
	Fleming County
	Franklin County
	Fulton County

STATE	COUNTY
	Graves County
	Grayson County
	Green County
	Greenup County
	Hancock County
	Hardin County
	Hart County
	Henderson County
	Henry County
	Hickman County
	Hopkins County
	Larue County
	Lewis County
	Lincoln County
	Livingston County
	Logan County
	Lyon County
	Marion County
	Marshall County
	Mason County
	McCracken County
	McLean County
	Meade County
	Mercer County
	Metcalfe County
	Monroe County
	Muhlenberg County
	Nelson County
	Ohio County
	Powell County
	Pulaski County
	Rockcastle County
	Rowan County
	Russell County
	Scott County
	Shelby County
	Simpson County
	Spencer County
	Taylor County
	Todd County
	Trigg County
	Trimble County
	Union County
	Warren County
	Washington County
	Wayne County
	Webster County
LA	Allen Parish
	Avoyelles Parish
	Bossier Parish
	Evangeline Parish
	Grant Parish
	Iberville Parish
	Jefferson Davis Parish
	Natchitoches Parish
	Pointe Coupee Parish
	Rapides Parish
	Red River Parish
	Saint Landry Parish
MD	Allegany County
	Baltimore County
	Carroll County
	Cecil County
	Frederick County
	Garrett County
	Harford County
	Howard County
	Montgomery County
	Queen Anne's County
	Washington County
MI	Alcona County
	Allegan County
	Alpena County
	Arenac County
	Barry County
	Bay County
	Berrien County
	Branch County
	Calhoun County
	Cass County
	Clinton County
	Eaton County
	Genesee County
	Gladwin County
	Grand Traverse County
	Hillsdale County
	Huron County
	Ingham County
	Ionia County
	Iosco County
	Isabella County
	Jackson County
	Lapeer County
	Leelanau County
	Lenawee County
	Livingston County
	Macomb County
	Manistee County
	Mason County
	Mecosta County
	Missaukee County
	Muskegon County
	Oceana County
	Ogemaw County
	Oscoda County
	Ottawa County
	Saginaw County

STATE	COUNTY
	Saint Clair County
	Saint Joseph County
	Sanilac County
	Shiawassee County
	Tuscola County
	Washtenaw County
	Wayne County
MN	Aitkin County
	Anoka County
	Becker County
	Beltrami County
	Benton County
	Big Stone County
	Carver County
	Cass County
	Chippewa County
	Chisago County
	Clay County
	Clearwater County
	Cottonwood County
	Crow Wing County
	Dakota County
	Dodge County
	Douglas County
	Fillmore County
	Freeborn County
	Goodhue County
	Grant County
	Hennepin County
	Houston County
	Hubbard County
	Isanti County
	Jackson County
	Kanabec County
	Kandiyohi County
	Lac qui Parle County

STATE	COUNTY
	Lake of the Woods County
	Le Sueur County
	Lincoln County
	Lyon County
	Mahnomen County
	Marshall County
	McLeod County
	Meeker County
	Mille Lacs County
	Morrison County
	Mower County
	Murray County
	Norman County
	Olmsted County
	Otter Tail County
	Pennington County
	Pine County
	Pipestone County
	Polk County
	Pope County
	Red Lake County
	Redwood County
	Rice County
	Roseau County
	Scott County
	Sherburne County
	Sibley County
	Stearns County
	Steele County
	Stevens County
	Swift County
	Todd County
	Traverse County
	Wabasha County
	Wadena County
	Washington County

STATE	COUNTY
	Wilkin County
	Winona County
	Wright County
	Yellow Medicine County
MO	Adair County
	Andrew County
	Atchison County
	Audrain County
	Barry County
	Barton County
	Bates County
	Benton County
	Bollinger County
	Boone County
	Buchanan County
	Butler County
	Caldwell County
	Callaway County
	Cape Girardeau County
	Carroll County
	Cass County
	Cedar County
	Chariton County
	Clark County
	Clay County
	Clinton County
	Cole County
	Cooper County
	Dade County
	Daviess County
	DeKalb County
	Dunklin County
	Franklin County
	Gasconade County
	Gentry County
	Greene County

STATE	COUNTY
	Grundy County
	Harrison County
	Henry County
	Hickory County
	Holt County
	Howard County
	Jackson County
	Jasper County
	Johnson County
	Knox County
	Lafayette County
	Lawrence County
	Lewis County
	Lincoln County
	Linn County
	Livingston County
	Macon County
	Madison County
	Marion County
	Mercer County
	Moniteau County
	Monroe County
	Montgomery County
	Morgan County
	New Madrid County
	Newton County
	Nodaway County
	Perry County
	Pettis County
	Pike County
	Platte County
	Polk County
	Putnam County
	Ralls County
	Randolph County
	Ray County
	Saint Charles County
	Saint Clair County
	Saint Francois County
	Saint Louis County
	Sainte Genevieve County
	Saline County
	Schuyler County
	Scotland County
	Scott County
	Shelby County
	Stoddard County
	Sullivan County
	Vernon County
	Warren County
	Wayne County
	Worth County
MS	Adams County
	Alcorn County
	Benton County
	Calhoun County
	Chickasaw County
	Clay County
	Covington County
	DeSoto County
	George County
	Humphreys County
	Leake County
	Lee County
	Leflore County
	Lowndes County
	Monroe County
	Noxubee County
	Pontotoc County
	Sunflower County
	Union County
	Washington County
MT	Blaine County
	Broadwater County
	Chouteau County
	Daniels County
	Dawson County
	Fallon County
	Gallatin County
	Glacier County
	Golden Valley County
	Hill County
	Liberty County
	McCone County
	Petroleum County
	Phillips County
	Pondera County
	Roosevelt County
	Sheridan County
	Teton County
	Toole County
	Valley County
NC	Alamance County
	Anson County
	Burke County
	Cabarrus County
	Catawba County
	Cherokee County
	Clay County
	Cleveland County
	Davidson County
	Davie County
	Durham County
	Franklin County
	Gaston County
	Henderson County
	Hyde County

STATE	COUNTY
	Iredell County
	Lincoln County
	Mecklenburg County
	Mitchell County
	Orange County
	Pasquotank County
	Randolph County
	Rowan County
	Stanly County
	Surry County
	Transylvania County
	Union County
	Warren County
	Wilkes County
	Yadkin County
ND	Adams County
	Barnes County
	Benson County
	Billings County
	Bottineau County
	Bowman County
	Burke County
	Burleigh County
	Cass County
	Cavalier County
	Dickey County
	Divide County
	Dunn County
	Eddy County
	Emmons County
	Foster County
	Grand Forks County
	Grant County
	Griggs County
	Hettinger County
	Kidder County

STATE	COUNTY
	LaMoure County
	Logan County
	McHenry County
	McIntosh County
	McLean County
	Mercer County
	Morton County
	Mountrail County
	Nelson County
	Oliver County
	Pembina County
	Pierce County
	Ramsey County
	Ransom County
	Renville County
	Richland County
	Rolette County
	Sargent County
	Sheridan County
	Slope County
	Stark County
	Steele County
	Stutsman County
	Towner County
	Walsh County
	Ward County
	Wells County
	Williams County
NE	Adams County
	Antelope County
	Banner County
	Boone County
	Box Butte County
	Boyd County
	Buffalo County
	Burt County

STATE	COUNTY
	Butler County
	Cass County
	Cedar County
	Clay County
	Colfax County
	Cuming County
	Dakota County
	Dawes County
	Dixon County
	Dodge County
	Fillmore County
	Franklin County
	Furnas County
	Gage County
	Gosper County
	Greeley County
	Hall County
	Hamilton County
	Harlan County
	Holt County
	Howard County
	Jefferson County
	Johnson County
	Kearney County
	Kimball County
	Knox County
	Lancaster County
	Madison County
	Merrick County
	Nance County
	Nemaha County
	Nuckolls County
	Otoe County
	Pawnee County
	Perkins County
	Phelps County

STATE	COUNTY
	Pierce County
	Platte County
	Polk County
	Red Willow County
	Richardson County
	Saline County
	Sarpy County
	Saunders County
	Seward County
	Sherman County
	Stanton County
	Thayer County
	Thurston County
	Valley County
	Washington County
	Wayne County
	Webster County
	Wheeler County
	York County
NJ	Hunterdon County
	Warren County
NM	Curry County
	Quay County
	Roosevelt County
NY	Albany County
	Allegany County
	Broome County
	Cattaraugus County
	Cayuga County
	Chautauqua County
	Chemung County
	Chenango County
	Clinton County
	Columbia County
	Cortland County

STATE	COUNTY
	Dutchess County
	Erie County
	Franklin County
	Genesee County
	Herkimer County
	Jefferson County
	Lewis County
	Livingston County
	Madison County
	Monroe County
	Montgomery County
	Niagara County
	Oneida County
	Onondaga County
	Ontario County
	Orleans County
	Oswego County
	Otsego County
	Rensselaer County
	Saint Lawrence County
	Saratoga County
	Schoharie County
	Schuyler County
	Seneca County
	Steuben County
	Tioga County
	Tompkins County
	Washington County
	Wayne County
	Wyoming County
	Yates County
OH	Adams County
	Allen County
	Ashland County
	Ashtabula County
	Athens County

STATE	COUNTY
	Auglaize County
	Brown County
	Butler County
	Champaign County
	Clark County
	Clermont County
	Clinton County
	Columbiana County
	Coshocton County
	Crawford County
	Darke County
	Defiance County
	Delaware County
	Fairfield County
	Fayette County
	Franklin County
	Fulton County
	Gallia County
	Greene County
	Hardin County
	Highland County
	Hocking County
	Holmes County
	Huron County
	Jackson County
	Knox County
	Licking County
	Logan County
	Lorain County
	Madison County
	Mahoning County
	Marion County
	Medina County
	Mercer County
	Montgomery County
	Morgan County

STATE	COUNTY
	Morrow County
	Muskingum County
	Perry County
	Pickaway County
	Pike County
	Portage County
	Preble County
	Richland County
	Ross County
	Sandusky County
	Scioto County
	Seneca County
	Shelby County
	Stark County
	Trumbull County
	Tuscarawas County
	Union County
	Warren County
	Wayne County
	Williams County
	Wyandot County
OK	Alfalfa County
	Beckham County
	Blaine County
	Bryan County
	Caddo County
	Canadian County
	Cimarron County
	Cotton County
	Craig County
	Custer County
	Garfield County
	Grant County
	Greer County
	Harmon County
	Harper County
	Jackson County
	Jefferson County
	Kay County
	Kingfisher County
	Kiowa County
	Le Flore County
	Major County
	McCurtain County
	Muskogee County
	Ottawa County
	Roger Mills County
	Sequoyah County
	Texas County
	Tillman County
	Tulsa County
	Wagoner County
	Washita County
OR	Benton County
	Gilliam County
	Linn County
	Marion County
	Morrow County
	Polk County
	Sherman County
PA	Adams County
	Allegheny County
	Armstrong County
	Beaver County
	Bedford County
	Berks County
	Blair County
	Bradford County
	Butler County
	Cambria County
	Carbon County
	Centre County
	Chester County
	Clarion County
	Clearfield County
	Clinton County
	Columbia County
	Crawford County
	Cumberland County
	Dauphin County
	Erie County
	Fayette County
	Franklin County
	Fulton County
	Greene County
	Huntingdon County
	Indiana County
	Jefferson County
	Juniata County
	Lancaster County
	Lawrence County
	Lebanon County
	Lehigh County
	Luzerne County
	Lycoming County
	Mercer County
	Mifflin County
	Monroe County
	Montour County
	Northumberland County
	Perry County
	Potter County
	Schuylkill County
	Snyder County
	Somerset County
	Sullivan County
	Union County

STATE	COUNTY
	Venango County
	Warren County
	Washington County
	Westmoreland County
	York County
SC	Cherokee County
	Chesterfield County
SD	Aurora County
	Beadle County
	Bennett County
	Bon Homme County
	Brookings County
	Brown County
	Brule County
	Buffalo County
	Campbell County
	Charles Mix County
	Clark County
	Clay County
	Codington County
	Davison County
	Day County
	Deuel County
	Douglas County
	Edmunds County
	Faulk County
	Grant County
	Gregory County
	Haakon County
	Hamlin County
	Hand County
	Hanson County
	Hughes County
	Hutchinson County
	Hyde County
	Jackson County
	Jerauld County
	Jones County
	Kingsbury County
	Lake County
	Lincoln County
	Lyman County
	Marshall County
	McCook County
	McPherson County
	Meade County
	Miner County
	Minnehaha County
	Moody County
	Pennington County
	Perkins County
	Potter County
	Roberts County
	Sanborn County
	Spink County
	Stanley County
	Sully County
	Tripp County
	Turner County
	Union County
	Walworth County
	Yankton County
TN	Bedford County
	Benton County
	Bledsoe County
	Blount County
	Bradley County
	Cannon County
	Carroll County
	Cheatham County
	Chester County
	Clay County
	Cocke County
	Coffee County
	Crockett County
	Davidson County
	Decatur County
	DeKalb County
	Dickson County
	Dyer County
	Fayette County
	Franklin County
	Gibson County
	Giles County
	Grundy County
	Hamblen County
	Hardeman County
	Hardin County
	Haywood County
	Henderson County
	Henry County
	Hickman County
	Houston County
	Humphreys County
	Jackson County
	Jefferson County
	Lauderdale County
	Lawrence County
	Lewis County
	Lincoln County
	Loudon County
	Macon County
	Madison County
	Marion County
	Marshall County
	Maury County
	McMinn County

STATE	COUNTY
	McNairy County
	Meigs County
	Monroe County
	Montgomery County
	Obion County
	Perry County
	Polk County
	Robertson County
	Rutherford County
	Sequatchie County
	Smith County
	Stewart County
	Sumner County
	Tipton County
	Trousdale County
	Warren County
	Wayne County
	Weakley County
	White County
	Williamson County
TX	Archer County
	Armstrong County
	Bailey County
	Bell County
	Borden County
	Bosque County
	Bowie County
	Brazoria County
	Callahan County
	Cameron County
	Carson County
	Castro County
	Chambers County
	Childress County
	Clay County
	Cochran County
	Coleman County
	Collin County
	Collingsworth County
	Comanche County
	Concho County
	Cooke County
	Coryell County
	Cottle County
	Crosby County
	Dallam County
	Dallas County
	Dawson County
	Deaf Smith County
	Delta County
	Denton County
	Ellis County
	Falls County
	Fannin County
	Fisher County
	Floyd County
	Gaines County
	Glasscock County
	Gray County
	Grayson County
	Guadalupe County
	Hale County
	Hall County
	Hamilton County
	Hansford County
	Hardeman County
	Harris County
	Hartley County
	Haskell County
	Hidalgo County
	Hill County
	Hockley County
	Howard County
	Hunt County
	Jackson County
	Jefferson County
	Johnson County
	Jones County
	Karnes County
	Kaufman County
	Lamar County
	Lamb County
	Limestone County
	Lubbock County
	Lynn County
	Martin County
	Matagorda County
	McCulloch County
	McLennan County
	Milam County
	Mills County
	Mitchell County
	Montague County
	Moore County
	Navarro County
	Nolan County
	Nueces County
	Ochiltree County
	Parmer County
	Randall County
	Reagan County
	Red River County
	Robertson County
	Rockwall County
	Runnels County
	San Patricio County
	Schleicher County
	Scurry County

STATE	COUNTY
	Sherman County
	Swisher County
	Taylor County
	Terry County
	Throckmorton County
	Tom Green County
	Uvalde County
	Wharton County
	Wheeler County
	Wichita County
	Wilbarger County
	Willacy County
	Williamson County
	Yoakum County
UT	Box Elder County
	Cache County
	Davis County
	Emery County
	Garfield County
	Juab County
	Millard County
	Morgan County
	Piute County
	San Juan County
	Sanpete County
	Sevier County
	Utah County
	Wayne County
	Weber County
VA	Albemarle County
	Amelia County
	Appomattox County
	Augusta County
	Bath County
	Brunswick County
	Buckingham County
	Campbell County
	Caroline County
	Charlotte County
	Clarke County
	Culpeper County
	Cumberland County
	Dinwiddie County
	Fauquier County
	Fluvanna County
	Franklin County
	Frederick County
	Goochland County
	Greene County
	Halifax County
	Hanover County
	King George County
	King William County
	Loudoun County
	Louisa County
	Lunenburg County
	Madison County
	Mecklenburg County
	Nelson County
	Nottoway County
	Orange County
	Page County
	Pittsylvania County
	Powhatan County
	Rappahannock County
	Richmond County
	Rockbridge County
	Rockingham County
	Shenandoah County
	Spotsylvania County
	Stafford County
	Wythe County
VT	Addison County
	Franklin County
	Grand Isle County
WA	Adams County
	Benton County
	Columbia County
	Douglas County
	Ferry County
	Franklin County
	Garfield County
	Grant County
	Kittitas County
	Klickitat County
	Okanogan County
	Skagit County
	Snohomish County
	Spokane County
	Stevens County
	Walla Walla County
	Whatcom County
	Whitman County
	Yakima County
WI	Adams County
	Ashland County
	Barron County
	Bayfield County
	Brown County
	Buffalo County
	Burnett County
	Calumet County
	Chippewa County
	Clark County
	Columbia County
	Crawford County

STATE	COUNTY
	Dane County
	Dodge County
	Door County
	Dunn County
	Eau Claire County
	Fond du Lac County
	Grant County
	Green County
	Green Lake County
	Iowa County
	Jackson County
	Jefferson County
	Juneau County
	Kenosha County
	Kewaunee County
	La Crosse County
	Lafayette County
	Manitowoc County
	Marquette County
	Monroe County
	Oconto County
	Outagamie County
	Ozaukee County
	Pepin County
	Pierce County
	Polk County
	Portage County
	Racine County
	Richland County
	Rock County
	Rusk County
	Saint Croix County
	Sauk County
	Shawano County
	Sheboygan County
	Trempealeau County
	Vernon County
	Walworth County
	Washburn County
	Washington County
	Waupaca County
	Waushara County
	Winnebago County
	Wood County
WV	Berkeley County
	Greenbrier County
	Hardy County
	Jefferson County
	Mason County
	Mineral County
	Preston County
	Tucker County
WY	Big Horn County
	Crook County
	Laramie County
	Lincoln County
	Weston County

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The American Carbon Registry™

Methodology for Compost Additions to Grazed Grasslands

Version 1.0

October 2014





American Carbon Registry

A nonprofit enterprise of

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A. Methodology Description

A.1 Acronyms

ACR	American Carbon Registry
CDM	Clean Development Mechanism
CH_4	Methane
CO_2	Carbon Dioxide
EPA	Environmental Protection Agency
ERT	Emission Reduction Ton
GHG	Greenhouse Gas
N_2O	Nitrous Oxide
NRCS	Natural Resources Conservation Service
PBM	Process-based Biogeochemical Model
SOC	Soil Organic Carbon
VCS	Verified Carbon Standard
VVB	Validation and Verification Body

A.2 Background

Grazed grasslands are defined by the Natural Resource Conservation Service (NRCS) of the United States Department of Agriculture (USDA) as "land on which the vegetation is dominated by grasses, grass-like plants, shrubs and forbs." This definition includes land that contains forbs, shrubland, improved pastureland, and improved rangeland for which grazing is the predominant use (NRCS 2009). Adding compost to Grazed Grasslands can be an effective way to increase soil carbon sequestration and avoid emissions related to the anaerobic decomposition of organic waste material in landfills. In addition to climate benefits, adding compost stimulates forage growth and can improve the quality of soils. This document contains a methodology to account for the carbon sequestration and avoided GHG emissions related to compost additions to Grazed Grasslands, following specifications by the American Carbon Registry (ACR). The current version of this methodology includes only one project activity – compost addition to Grazed Grasslands. Additional project practices and additional organic soil amendment types may be added in future revisions. This approach will allow the experience gained from the first projects to be incorporated in future versions of the methodology.

Grassland soils are an important sink for carbon, accounting for approximately 20 % of the world's soil carbon stocks (FAOSTAT 2009; Conant 2010). The amount of carbon stored in grassland soils is largely driven by environmental conditions such as temperature, rainfall, and soil characteristics, as well as the productivity of various grassland plant communities (Derner and Schuman 2007). These factors are subject to temporal variability both within seasons and across multiple years (Svejcar et al. 2008; Ingrahm et al. 2008). Many grasslands in the US have been degraded through overgrazing which in some cases can lead to declines in soil organic matter (Conant and Paustian 2002). However, research also suggests that with improved management grassland soils can also offer considerable potential to aid greenhouse mitigation efforts through additional soil carbon sequestration (Lal 2002; Conant and Paustian 2002; Derner and Schuman 2007).

One management strategy that may hold promise for enhancing carbon sequestration in grasslands is the application of organic soil amendments such as compost or composted biosolids. A growing body of research indicates that the application of these organic materials can often have positive impacts on the amount of carbon stored in both grassland (Walter et al. 2006; Ippolito et al. 2010; Kowaljow et al. 2010; Ryals et al. 2014) and cropland soils (Canali et al. 2004; Celic et al. 2004; Montovi et al. 2005; Cai and Qin 2006). The buildup of soil carbon occurs via two mechanisms; 1) directly from carbon contained in the compost, and 2) indirectly through enhanced plant growth and subsequent deposition of plant biomass (Walton et al. 2001; Walter et al. 2006; Ryals and Silver 2013). The recent model work of Zhai et al. 2014 demonstrates gains in soil organic carbon due to application of biosolids for 10 years, with further SOC gains over the next 10 or more years due to biomass and/or carbon sequestration.

A number of peer-reviewed studies involving the application of compost or composted biosolids to temperate grasslands have been carried out over both short-term (0-5 yrs) and long-term (5-14 yrs) experimental periods. At two Mediterranean grassland sites in California, Ryals et al. (2014) measured C sequestration years after a single compost addition. Compost amendment resulted in a significant increase in bulk soil organic C content at a Central Valley site, and a similar but non-significant trend at a Coast Range site. Compost additions also significantly increased plant growth as measured by net primary productivity at both the Central Valley and Coast Range sites (Ryals and Silver 2013). Likewise, in a three year study conducted at a semi-arid steppe site in northwest Patagonia, the application of composted biosolids (40 t ha-1) also increased plant growth and soil organic matter relative to an untreated control (Kowaljow et al. 2010). More importantly, several long-term grassland experiments have also found that the effect of compost application on plant growth and soil C can persist for more than a decade (Sullivan et al. 2006; Ippolito et al. 2010; Walton et al. 2001). For instance, at a semi-arid grassland site in Colorado differences in plant growth (Sullivan et al. 2006) and total soil C (Ippolito et al. 2010) were still detectable 14 years after applying compost at 6 different rates (0, 2.5, 5, 10, 21, and 30 t ha-1). Similarly Walton et al. (2001) found that 32% of applied biosolids remained as particles greater than 2mm 18 years after application to an arid rangeland site in New Mexico. The above-mentioned studies and others in the broader peer-reviewed literature provide evidence that compost application to grasslands can facilitate long-term soil C sequestration and improved plant growth, and thus form the scientific basis for the current methodology.

A.3 Summary Description of the Methodology

Compost additions to Grazed Grasslands can generate Emission Reduction Tons (ERTs) from avoided Greenhouse Gas (GHG) emissions and removals resulting from three processes:

1) **Avoidance of anaerobic decomposition (Optional)** of the organic material used in compost production. Methane (CH_4) emissions that result from anaerobic decomposition of the organic material used in the production of compost under baseline conditions – for example, when the organic matter is buried in landfills – can be avoided by composting[1] and applying compost on Grazed Grasslands. It is not required in this methodology to include the avoided emissions from preventing the anaerobic decomposition of the organic material used in the production of compost. However, if these avoided emissions are included, evidence must be provided that (1) the avoided emissions have not been claimed under a different Carbon Credit program, such as the Climate Action Reserve's composting methodology, and that (2) the baseline fate of the organic matter can be demonstrated following the procedures included in Section C of this methodology.
2) **Direct increase in soil organic carbon (SOC) content (Required)** through adding a carbon source from compost. The carbon (C) content of applied compost will lead to a direct increase in soil organic carbon (SOC) content of the Grazed Grasslands where the compost is applied. Even though the carbon added through compost additions will gradually decompose over time, a significant portion will end up in stable carbon pools. The portion of the compost carbon that will remain in the stable pools is likely to be greater than the portion that would be stabilized under baseline conditions. Only the stable carbon pools that are predicted to remain after 40 years after compost addition can be counted. These stable soil C pools are conceptually equivalent to the "intermediate" and "passive" C pools defined in recent literature reviews by Trumbore (1997) and Adams *et al.* (2011). This 40 year period is also similar in duration to the 40 year minimum project term used in the approved ACR Forest Carbon Project protocol (ACR 2010). As such, the minimum project period for this protocol is 40 years.
3) **Indirect increase in SOC sequestration (Required)** through enhanced plant growth in Grazed Grasslands amended with compost. The N and P content of the compost, as well as the improved soil water holding capacity of soils amended with compost, may in some cases lead to an indirect increase in SOC content through an increase in net primary productivity (NPP). The impact of compost on SOC content will depend on the compost's nutrient content and availability, the soil properties, and grazing management strategies.

This methodology requires the use of a model to predict direct and indirect changes in SOC under the baseline and project scenarios. This methodology does not prescribe a specific model. The model can be either a process-based biogeochemical model (PBM) such as the DAYCENT or Denitrification-Decomposition (DNDC) models, or an empirical model such as a Tier-2 Empirical Model that is shown to

[1] Whereas composting is mostly an aerobic process that occurs in presence of oxygen, composting may still release a small amount of methane.

be effective for the conditions of the Project Parcels (see Section D.1). It is up to the project proponents to demonstrate that the model is sufficiently accurate for the Project Parcels (see section D.1 for model requirements). Under the baseline scenario, the model is used to simulate any on-going changes to SOC, including potential continuing loss of SOC. Under the project scenario, the model is used to simulate the amount of compost carbon that is stored in recalcitrant SOC pools, and any indirect changes in SOC due to an increase in net primary production and under specific grazing management strategies. Even though empirical models and PBMs have been shown to be highly valid across a wide range of management practices and geographic areas, soil samples and field measurements are required to validate the models for use in specific Project Parcels. As a consequence, this methodology requires monitoring by periodic (10 year) analyses of soil samples for model validation at different times throughout the project's lifetime.

Adding compost to Grazed Grasslands has the potential to increase GHG emissions from secondary sources. Specifically, N_2O emissions from soils are produced due to nitrification and de-nitrification of the available N added through the compost addition (Box 1). These processes further require a carbon source, which is readily available after compost addition. Indirect emissions from nitrate leaching may also occur but GHG emissions resulting from the leached nitrate are expected to be insignificant, at the rate compost is applied in projects under this methodology based on findings reported by DeLonge et al. (2013) for California grasslands. In addition to soil N_2O emissions (from de-nitrification), all emissions from fuel that was used to create, transport, or apply the compost is included in the quantification procedure. Under this methodology, soil N_2O emissions are quantified using an applicable Tier-2 Empirical Model, or a calibrated PBM. The GHG emissions from increased fuel use must be quantified using standard emission factors. Likewise, enteric emissions from increases in stocking must be quantified with the ACR Grazing Land and Livestock Management MICROSCALE Tool for Tier I estimation of emissions from enteric methane.

Apart from the economic benefit of increased forage production, applying compost to Grazed Grasslands also has many environmental co-benefits, such as improved soil quality and increased nutrient and water availability for vegetation due to improved soil water holding capacity, which increases resilience to more intense precipitation events, slows the onset of drought, and confers additional ecosystem services. Compost application may also reduce erosion in certain contexts due to improvements in vegetation cover. Compost can be added to most existing Grazed Grasslands.

Box 1. Further background on N_2O fluxes after compost application

The magnitude of the N_2O fluxes after compost addition may be highly variable and difficult to predict. For example, in an experiment where N_2O fluxes were measured after a one-time compost addition on two sites in California, no significant increases in N_2O fluxes were observed (Ryals and Silver 2012). In laboratory incubations under controlled conditions, however, a pulse of N_2O emissions was detected in soils after compost addition that was significantly greater than soils to which no compost was added. However, the pulse was short-lived (four days), and represented only a very small component of the net soil GHG emissions (expressed as CO_2-equivalents) released from the controlled wet up event (Ryals and

Silver 2012). Such conditions represent ideal conditions for N_2O release and are unlikely to be present for a long period of time in the field. High-nitrogen organic materials such as manure or processed manure additions may be more prone to N_2O emissions. Due to the difficulty in predicting N_2O emissions, this methodology allows some flexibility in the approach to quantify N_2O.

Production of N_2O is generally greatest under warm and humid conditions and where soil nitrogen concentrations are highest. Therefore, the timing of compost application relative to weather conditions and plant demand is crucial to minimize N_2O emissions. If the Grazed Grassland is dominated by annual plants and the compost application occurs before plant establishment, a significant amount of inorganic N may remain in the soil, resulting in significant N_2O fluxes. However, in a Mediterranean climate, there is an ideal window for applying compost. Specifically, fall applications are preferred, ideally shortly before first rains and prior to plant establishment in annual-dominated grasslands. Once the soil gets wet, compost applications may become more logistically challenging due to restricted access to the field as well as less beneficial, while initial growth of annuals in response to early rains can be expected to help limit inorganic N losses from the soil. The ideal window for compost addition may be different for other climates. In this protocol we require following the advice from a Qualified Expert (i.e., a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent) as to when to apply compost.

A.4 Definitions

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry Standard apply.

Compost	The end product of a process of controlled aerobic decomposition of organic materials, consistent with California Department of Resources Recycling and Recovery (CalRecycle) standards (http://www.calrecycle.ca.gov/Laws/Regulations/Title14/ch31.htm).
Grassland	We follow the terminology of Allen et al. (2011), who indicate that the term grassland bridges pastureland and rangeland and may be either a natural or an imposed ecosystem. Grassland has evolved to imply a broad interpretation for lands committed to a forage use.
Grazed Grassland	Grassland on which annual grazing by livestock (including cattle, horses, sheep and goats) is the primary means of forage/biomass removal. In this protocol, if any grazing takes place on a yearly basis under historical baseline management the parcel may be considered “grazed” (see section E.1).
Native Grassland	A grassland where native plant species comprise greater than 10 percent of the

	total relative cover (Stromberg et al. 2007).
Process-based Biogeochemical Model	Computer model that is able to simulate biogeochemical processes and predict GHG fluxes, nutrient contents and/or water contents.
Project	The activities undertaken on a Project Parcel to generate GHG emission reductions.
Project Parcel	Individual contiguous parcel unit of grassland under control of the same entity/entities.
Qualified Expert	A Qualified Expert can be a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent. A Qualified Expert is a professional certified to provide consulting services on all activities devoted to rangeland resources. These services include, but are not limited to, making management recommendations, developing conservation plans and management plans, monitoring, and other activities associated with professional rangeland management.
Stocking Rate	The amount of land allocated to each livestock unit for the grazing period of each year, or alternatively, the number of livestock units per hectare for the grazing period. Stocking Rate must include the number of livestock units (LU)[2], land area per LU, and the amount of time a given number of LUs occupy a given unit of land. In case rotational grazing is employed, the Stocking Rate shall include specifics on the rotational grazing management, including such factors as species, numbers, length of stay, length of rest between grazing periods, frequency of return per annum or season, season(s) of use, etc.
Tier-2 Empirical Model	Empirical model such as a linear regression model calibrated for a specific region. In the context of this methodology, a Tier-2 Empirical Model predicts SOC content or N_2O emissions as a function of one or more driving variables, such as compost carbon added, nitrogen added, clay content, annual rainfall, etc.
Waste Material	The original material that was Composted.

[2] Livestock units (also known as animal units) are a standardized measure used by the UN Food and Agriculture Organization to quantify Stocking Rates for multiple animal types and growth stages based on an estimate of the metabolic weight of the animals. A livestock unit is measured as livestock unit/time/hectare. More information on the quantification of livestock units for grazing systems in North America can be found at: http://www.lrrd.org/lrrd18/8/chil18117.htm

A.5 Applicability Conditions

In addition to satisfying the latest ACR program requirements, project activities must satisfy the following conditions for this methodology to apply:

- The Project includes one or more Project Parcels that are Grazed Grasslands at the start of the Project and remain Grazed Grasslands for the duration of the Project (Box 2).
- The annual, minimum and maximum Stocking Rate shall be determined via consultation with a Qualified Expert (see definitions – a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent) and duly justified by the Project Proponent. Justification for the annual Stocking Rate should include a calculation of the historical Stocking Rate averaged over a 5 year period prior to the start of the Project, and an assessment of whether or not the forage productivity and quality of the parcel can sustainably support the historical Stocking Rate. In some cases the conditions of the parcel will justify using the historical Stocking Rate as the annual, while in other cases the Qualified Expert may set an annual Stocking Rate that differs from the historical Stocking Rate. Validation of the GHG project plan will include a review of the criteria used by the Qualified Expert to ensure annual Stocking Rates during the Project lifetime are sustainable, and will not lead to erosion or negatively affect species composition; subsequent verifications will review changes to the annual Stocking Rate and ensure that a Qualified Expert was properly consulted. The maximum Stocking Rate shall be set so that rangeland utilization remains sustainable, taking into account an increase in forage production and any changes in the percentage of grazer feed coming from purchased sources after the start of the crediting period.[3] The minimum Stocking Rate shall be set to ensure that plant community species composition does not change toward a less desirable plant community in response to soil quality changes following compost application.
- Any soils that are regularly flooded (i.e. more than two months per year), shall be excluded from the Project Parcels.[4] At the start of the Project the Qualified Expert must identify any land within the parcel that ought to be excluded due to a high likelihood of annual flooding. These areas can be detected by observing the topographic position in the landscape, as well as clear shifts in vegetation and soil redox features (e.g. gleying). These areas must be excluded from the Project Parcel at the beginning of the crediting period. Additionally, and in consultation with a Qualified Expert, compost application should occur in accordance with local and/or state regulations regarding application and water quality concerns. In order to prevent any unintended negative impact on forage growth, compost should not be more than ½ inch in depth at any part of the application area.
- The compost added to the Project Parcel must be within the following specifications:

[3] This approach is fully compatible with a rotational grazing strategy.

[4] The no-flood requirement is added to prevent the inclusion of land areas where a significant amount of CH_4 is likely to be emitted from soils in the project area; the accounting for methanogenesis is not included.

- The final end product after composting must have a nitrogen concentration of less than 3%[5] on a dry-weight basis.
- Best Management Practices put forward by state agencies have been followed in making the compost free of any seeds or propagules capable of germination or growth.
- The heavy metal and contaminant content of composts shall not exceed limits of the US EPA under 40 CFR 503.[6]
- The compost must be produced in accordance with Chapter 5 of EPA Part 503 Biosolids Rule process to further reduce pathogens (PFRP) and other contaminants.[7]
- Waste Material containing food waste or manure must be either (1) mixed and incorporated into the composting process within 24 hours of delivery of the waste to the composting facility, (2) covered or blended with a layer of high-carbon materials such as wood chips or finished compost within 24 hours of delivery, and mixed and incorporated into the composting process no more than 72 hours after delivery, (3) placed in a controlled environment within 24 hours of delivery, or (4) handled using any other alternative Best Management Practices to avoid anaerobic decomposition after delivery and before incorporation into the composting process of the source material.[8] Compost material that was produced consistently with the standards put forward by the California Department of Resources Recycling and Recovery is automatically approved.

Box 2. Further background on species composition changes and minimum grazing requirements

Compost applications may lead to changes in the plant community (either positive or negative) due to impacts of compost on nutrient concentrations and hydrology of treated soils (Bremer, 2009). The protocol does not support application of compost to intact, healthy native plant communities. Whether a grassland constitutes a healthy native plant community is best determined in consultation with a

[5] This would prevent materials that more closely resemble synthetic fertilizers from being used as an amendment.

[6] Because compost may contain trace levels of heavy metals, limits on the heavy metal contents in fertilizers, organic amendments, and biosolids are regulated through US EPA, 40 CFR Part 503. Under EPA regulations, managers must maintain records on the cumulative loading of trace elements only when bulk biosolids do not meet EPA Exceptional Quality Standards for trace elements.

[7] Chapter 5 focuses on Pathogen and Vector Attraction Reduction Requirements. On page 116, the Process to Further Reduce Pathogens is defined as "*using either the within-vessel composting method or the static aerated pile composting method, the temperature of the biosolids is maintained at 55/degree C or higher for 3 days. Using the windrow composting method, the temperature of the biosolids is maintained at 55/degree C for 15 days or longer. During the period when the compost is maintained at 55/degree C or higher, the windrow is turned a minimum of five times.*". The text is available at http://water.epa.gov/scitech/wastetech/biosolids/upload/2002_06_28_mtb_biosolids_503pe_503pe_5.pdf

[8] These requirements will ensure that emissions from storing waste at the composting facility are negligible, as justified in the "Organic Waste Composting Project Protocol" approved for use under the Climate Action Reserve.

qualified expert, as native plant communities are defined by their geography and are thus impacted by local conditions. Species composition may also change where grazing is discontinued due to factors unrelated to the project activity, such as extended periods of drought.[9] To reduce this risk, validation of the GHG project plan will include a review of the criteria used by the Qualified Expert to ensure that annual Project Stocking Rates will not contribute to erosion or otherwise negatively impact plant species composition. Changes to the annual Stocking Rate will be assessed during each subsequent verification to ensure changes were implemented in consultation with a Qualified Expert. The minimum Stocking Rate shall be set to ensure that plant community species composition is not negatively affected in response to soil quality improvement following compost application.

[9] Guidance on best practices for drought management can be found online at: http://pss.okstate.edu/publications/publications-master-list/copy_of_publications/forages/F-2870web.pdf

B. Project Boundaries

B.1 Geographic Boundary

B.1.1 Project Parcel

The GHG removals from carbon sequestration in the soil organic carbon pools of the Project Parcels are the focus of this methodology. The geographical boundary encompassing these Project Parcels is, therefore, the main geographic boundary of the Project. The geographical coordinates of the boundaries of each Project Parcel must be unambiguously defined by providing geographic coordinates.

New Project Parcels may be added to an existing Project after the start of the crediting period as long as all the applicability criteria are met for each individual Project Parcel, as outlined in ACR's most recent Standard.

B.1.2 Composting Facility (Optional)

In case GHG emission reductions from composting source material and avoidance of anaerobic decomposition are claimed as Emission Reduction Tons (ERTs) under this methodology, the composting facility shall be included in the geographic boundary. In this case, the project proponent(s) shall include a formal affidavit indicating that the emission reductions from composting source material and avoidance of anaerobic decomposition have never been claimed under any compliance or voluntary carbon registry. This affidavit would be issued by the project proponent(s) but will also include a signature from the owner of the composting facility attesting that the facility is not claiming carbon credits.

In case emission reductions from composting source materials are not claimed by the project participants, the composting facility is excluded from the Project's Geographic Boundary.

B.1.3 Stratification

This methodology encourages combining Project Parcels spread over a large geographic region within one Project to reduce costs. However, environmental, soil, and management conditions may not be homogeneous across a large geographic region. Non-homogeneous conditions may affect the validity of baseline calculations and additionality checks. Therefore, heterogeneous Project Parcels shall be subdivided into smaller units or strata that are considered homogeneous for the purpose of carbon accounting. A different set of input parameters to the model(s) for carbon accounting selected in Section D.1 shall be prepared for each different stratum. Parameters that shall be considered to stratify the Project Parcels are:

- Historical rangeland management practices
- Future rangeland management practices after the start of the Project

- Different soil types, especially special status soils (e.g., serpentine soils, histosols, etc.); official soil series description
- Ecological characteristics (soil texture, aspect, slope, hydrology, climate, plant communities)
- Degradation status (initial soil C content, soil bulk density)
- Differences in legally binding requirements affecting management of the Project (e.g., easement status of land, ownership)

The stratification must be conducted or approved by a Qualified Expert. A description and justification of the stratification procedure must be included in the GHG Project Plan. All subsequent procedures in this methodology, including baseline scenario identification and additionality tests must treat each identified stratum separately.

B.2 Greenhouse Gas Boundary

This section includes all sources, sinks, and reservoirs that are quantified in this methodology.

Baseline scenario:

- Emissions resulting from anaerobic decay of organic waste at a final disposal/treatment system (e.g., landfill or manure management system). This source is optional and may be omitted; doing so is conservative. If the composting facility will claim emission reductions from avoiding emissions from anaerobic decay of organic waste, this source may not be included in the GHG accounting for the project. If this source of emission reductions is claimed by the Project, the project proponent(s) shall include a formal affidavit indicating that no other party than the project proponent(s) have claimed the emission reductions from composting source material and avoidance of anaerobic decomposition under any compliance or voluntary carbon registry.
- Background changes of SOC, potentially related to continuous loss of soil organic carbon[10] of the Grassland as predicted through modeling.
- Enteric fermentation CH_4 emissions from ruminants grazing on project parcels.

Project scenario:

- Emissions resulting from the composting process, including active composting and curing of compost at project facilities. To avoid double deductions, this source of emissions shall be omitted in case the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste.
- Enteric fermentation CH_4 emissions from ruminants grazing on project parcels.
- Fossil fuel emissions from the transport of the finished compost to the Project Parcels.
- Emissions related to the land application of compost.

[10] Some evidence indicates that many grasslands are losing soil carbon (Chou *et al*. 2008, Ryals et al. submitted). Through compost additions, one may be able to slow down or reverse the carbon loss (Ryals & Silver 2013).

- Emissions of CO_2 and N_2O related to the decomposition of compost after application.
- Sequestration of carbon related to the increase in plant productivity on the grassland.
- Sequestration related to the transfer of compost into recalcitrant SOC pools.[11]

Fossil fuel emissions from transport of organic waste materials to final disposal/treatment system (e.g. garbage trucks, hauling trucks, etc.) under baseline conditions are assumed to be equal to the fossil fuel emissions from transporting waste materials to the compost facility in the project case[12], and are therefore not included in the GHG accounting (Brown et al. 2009).

The GHG emissions from storage of waste in the composting facility are assumed to be insignificant when the applicability conditions laid out in Section A.5 are followed.

[11] Only carbon stored in recalcitrant soil pools is considered sequestered

[12] Note that in case of on-farm composting, the fossil fuel emissions will likely be smaller in the project scenario. However, it is conservative to omit this extra emission reduction in case of on-farm composting.

Table 1. Overview of included Greenhouse Gas sources.

	Source	Gas	Included?	Justification/Explanation
Baseline	Project Parcels soil	CO_2	Yes	Emissions from decomposition of soil organic carbon
		CH_4	No	Non-flooded soils can be a source or sink of Methane but fluxes are negligible.
		N_2O	Yes	Nitrous oxide emissions from non-fertilized grassland soils are small but not negligible.
	Landfill or other waste sink	CO_2	Yes/No	Carbon dioxide emissions from organic materials are potentially significant in case these materials would have been deposited in landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone in the baseline scenario.
		CH_4	Yes/No	Methane emissions from organic materials are potentially significant in case these materials would have been deposited in landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone in the baseline scenario.
		N_2O	Yes/No	Nitrous oxide emissions from organic materials are potentially significant in case these materials would have been deposited in

				landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone.
	Ruminants	CH_4	Yes	Methane emissions from enteric fermentation from ruminants grazing on the land.
	Fossil fuel emissions from transport of organic waste to landfill	CO_2	No	Assumed to be equivalent to fossil fuel emissions from transport of organic waste to composting facility.
	Fossil fuel emissions from transport of imported forage	CO_2	No	Assumed to be conservative as project scenario is likely to require less importation of feed.
Project	Project Parcels soil	CO_2	Yes	Additional CO_2 emissions from compost application may occur and are included.
		N_2O	Yes	Additional N_2O emissions from compost application may occur and are included.
		CH_4	No	Non-flooded soils can be a source or sink of Methane but fluxes are negligible
	Ruminants	CH_4	Yes	Methane emissions from enteric fermentation from ruminants grazing on the land.
	Emissions due to leaching	N_2O	No	Secondary emissions from leachates of the composted material are negligible due to the complex nature of compost and the low nitrogen content of compost.
	Fossil fuel emissions from transport of organic waste	CO_2	No	Assumed to be equivalent to fossil fuel emissions from transport

	to the compost facility			of organic waste to landfill.
	Fossil fuel emissions from transport of compost to project parcel and application	CO_2	Yes	Assumed to be additional to the fossil fuel emissions from transport of organic waste to landfill or composting facility.
	Fossil fuel emissions from transport of imported forage	CO_2	No	Assumed to be conservative as project scenario is likely to require less importation of feed.
	Emissions due to composting	CO_2	No	Carbon dioxide emissions released during composting are biogenic. These emissions are not quantified in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5: Waste, Chapter 4: Biological Treatment of Solid Waste and therefore are not included in this calculation of project emissions.
		CH_4	Yes/No	Some methane may be produced during composting. To avoid double deductions, this source of emissions shall be omitted in case the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste.
		N_2O	No	Nitrous oxide emissions during composting are negligible.

Table 2. Overview of included pools (baseline and project)

Pool	Included in emissions reductions quantification	Rationale
Above-ground non-woody biomass	No	The above-ground non-woody biomass pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Below-ground non-woody biomass	No	The below-ground non-woody biomass pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Litter	No	The litter pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Dead wood	No	Not a major pool affected by project activities.
Soil	Yes	Potentially significantly affected by project activities. The increased forage production and the addition of compost are expected to increase the soil organic content.

B.3 Temporal Boundary

The project start date shall coincide with the first compost application event. The minimum project term will be 40 years due to the fact that the ERTs claimed as a result of the compost additions to grassland soils are calculated based on the stability of the "intermediate" and "passive" C pools being greater than 40 years (see Sections A.3 and D.2). The crediting period is defined by the ACR Standard as the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario.[13] The crediting period for each project will be 10 years and validation of the GHG Project Plan will occur once per crediting period. Crediting periods are limited in order to require project proponents to reconfirm at set intervals that the baseline scenario remains realistic, credible, additional, and that the current best GHG accounting practice is being used. Since ACR places no limit on the number of crediting period renewals, the project proponent may renew the crediting period in 10-year increments thereafter, provided that the project still meets the protocol requirements. The

[13] The current version of the ACR Standard can be found online at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

methodology allows for multiple compost applications as long as there are at least three years between each application and the new application rate is explicitly reviewed and approved by a Qualified Expert. The three-year rule, combined with the review of the Qualified Expert, is intended to allow enough time between compost additions so that any potential negative impacts on plant communities can be detected and mitigated before a new application is scheduled.

C. Procedure for Determining the Baseline Scenario and Demonstrating Additionality

Emission reductions from avoidance of anaerobic decomposition have very different additionality considerations than emission reductions from direct and indirect increases in SOC. Project proponents who are not claiming any ERTs from avoidance of anaerobic decomposition do not have to consider the additionality requirements related to this source of emission reductions, covered in Section C.1. Since all projects using this methodology will add compost to Grazed Grasslands, all project proponents shall follow the additionality requirements related to direct and indirect increases in SOC, covered in Section C.2.

C.1 Additionality of Emission Reductions from Avoidance of Anaerobic Decomposition

Project proponents shall use ACR's three-prong approach[14] to demonstrate additionality. Specifically, in cases where ERTs from landfill diversion are obtained, it must be demonstrated that the source material used for composting was diverted from a landfill or anaerobic manure storage facility. ERTs cannot be claimed in instances where the landfill or anaerobic processing facility that would otherwise receive the waste material cannot be identified, or if the facility from which source material was diverted already captures methane. Evidence must be provided demonstrating that the specific source of the waste material used for composting (e.g., the specific waste collector) has been deposited in a landfill or storage under anaerobic conditions (in the case of manure) for a period of five years prior to the project's starting date. Valid evidence includes economic analyses, reports, peer-reviewed literature, industry group publications, surveys, etc. Note that examples of the application of these approaches are provided in Section C.1.2.

C.1.1 Co-composting

Often, multiple waste sources are composted together to get an optimal composting C-to-N ratio and increase the waste streams that can be processed. This is referred to as co-composting. In case one of the materials used during co-composting is non-additional, the proportion of the waste that is additional shall be recorded and used in subsequent calculations in Section C.2 as parameter $f_{diverted}$. In case all the waste material is additional, $f_{diverted}$ shall be set to 1. The $f_{diverted}$ factor is used in subsequent calculations to discount any GHG benefits so that only additional benefits are counted.

[14] The three-prong test is described in detail in the ACR Standard.

C.1.2 Examples of determining additionality through diversion of waste materials

- Studies by *Biocycle Magazine*, referenced in a report published by the EPA in 2008,[15] estimate that, at a national level, 97.4% of solid food waste (e.g., milk solids, condemned animal carcasses, meat scraps, and pomace wastes from wineries) were landfilled in 2007. Therefore, compost made from solid food waste is additional without the need for any further evidence.
- The same report published by the EPA in 2008 estimated that 35.9% of the total quantity of yard waste was landfilled. Therefore, a project developer must demonstrate that the specific source of the waste material, i.e., the waste collector of a specific municipality, has landfilled the yard waste for a period of five years prior to the Project's starting date.
- California generates 750,000 dry tons of biosolids, the by-product of channeling human waste through treatment plants and collection systems (California Association of Sanitation Agencies). In total, 54% is land applied and 16% is composted according to statistics from CalRecycle, available at http://www.calrecycle.ca.gov/organics/biosolids/#Composting. Therefore, a project developer using compost derived from biosolids must demonstrate that the specific source of the biosolids, i.e., the biosolids of a specific municipality, have been landfilled in the past.
- The biosolids from sources that are already land-applied (currently 54%) are not compost and not considered additional under this methodology. However, these biosolids could potentially be co-composted by blending it with carbonaceous material such as paper diverted from landfills. The resulting compost is eligible to be used within this methodology on the condition that $f_{diverted}$ is set to the percentage of the compost feedstock (biosolids plus carbonaceous material) actually diverted from landfill.

C.2 Additionality of Emission Reductions from Increases in SOC

The additionality of emission reductions from direct or indirect increases in SOC related to the addition of compost to Grazed Grassland can be tested in a straightforward fashion using ACR's standard three-prong approach, based on Regulatory Surplus, Common Practice, and Implementation Barriers.

C.3 Baseline Determination

Once ACR's three-prong test is passed, the baseline management is set as a continuation of the historical management. The historical management is defined by acquiring the following three parameters for a period of at least five years[16] before the start of the Project:

- Stocking rates

[15] Municipal Solid Waste in the United States. 2007 Facts and Figures. Environmental Protection Agency Office of Solid Waste (5306P). EPA530-R-08-010. Available at http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1001UYV.PDF

[16] Note that in areas with a longer history of fire, significant changes in plant cover, or other disturbances, more details may be needed to adequately parameterize PBM models.

- Stocking periods
- Incidence of fires

The historical grazing management shall be duly described. These management parameters and other site-specific parameters that are required to define the baseline are included in the list of parameters available at model validation (Section E.1). Key parameters such as the site-specific grazing intensity, soil properties, and climate will be required for all baseline model validation efforts. However, since process based models vary in the ancillary input parameters that they require, appropriate discretion on what must be included will be given to those tasked with validating the model for a given site.

Baseline stocking rate shall be the average of at least 3 of the last 5 years prior to the project start date. The project proponent shall select the most representative years to include and must provide a verifiable justification of the year selection in the GHG project plan.

D. Quantification of GHG Emission Reductions and Removals

D.1 Requirements for Models used for Quantifying GHG emissions and removals

This methodology does not prescribe a model to quantify changes in SOC and soil N_2O emissions. A variety of models are eligible to quantify GHG emissions and removals on the condition that (1) project developers demonstrate the use of the selected model is sufficiently accurate for their study area, as explained in the remainder of this section, and (2) an appropriate uncertainty deduction is applied. Either PBMs or empirical models such as emission factors may be used. Multiple models may be used during the carbon accounting. For example, it is allowed to use a PBM for one variable, such as SOC, and use a Tier-2 Emission Factor for N_2O emissions. The remainder of this section contains general requirements related to the use of Tier-2 Empirical Models and PBMs.

The uncertainty deduction shall have two components: one component related to the inherent, or structural, uncertainty from the model, and another component related to the variability of the input data, such as the variability of the N content in the compost, or the soil texture. Each of the three potential quantification approaches detailed below contains a section on how to calculate structural uncertainty. The structural uncertainty shall further be adjusted for aggregation. The input uncertainty shall be calculated using a Monte Carlo approach and using a 90% confidence level. The two sources of uncertainty, structural uncertainty and input uncertainty, shall simply be summed to calculate the total uncertainty. For the N_2O and ΔSOC components, the total uncertainty shall be calculated as:

$$u_{total} = \frac{u_{struct}}{\sqrt{n}} + u_{input}$$

u_{total}	=	Total uncertainty deduction [MT CO_2-eq]
u_{struct}	=	Structural uncertainty deduction related to the use of a specific model [MT CO_2-eq]
n	=	Number of Project Parcels or the total size of the Project Parcels in hectares divided by 250, whichever is smallest [-]
u_{input}	=	Input uncertainty deduction [MT CO_2-eq]

D.1.1 Tier-2 Empirical Models

Project proponents may develop Tier-2 Empirical Models, which may be used once they appear in the peer-reviewed scientific literature. Project Proponents shall justify in the GHG Project Plan that the sampling locations to create the regionally applicable Tier-2 Empirical Models are representative for the Project. Data from at least five sites across two years must be used to calculate the Tier-2 Empirical Model.

STRUCTURAL UNCERTAINTY FOR TIER-2 EMPIRICAL MODELS

A bootstrapping method of resampling shall be used to estimate the deviation between measured and modeled emission reductions. The structural uncertainty shall be calculated as the half-width of the 90% confidence interval around the deviations and shall be deducted from the final ERTs.

INPUT UNCERTAINTY FOR TIER-2 EMPIRICAL MODELS

The input uncertainty shall be calculated using simple propagation of errors around input parameters such as the quantity of carbon or nitrogen added through the compost additions. The error shall equal the half-width of the 90% confidence interval, e.g., from the error around the N content of the compost.

D.1.2 Process-based Biogeochemical Models (PBMs)

PBMs such as Century, Daycent,[17] EPIC, ROTH-C, or DNDC may be used on the condition that they are validated for the conditions of the Project Parcels and for the specific variable that is under consideration (i.e., annual change in SOC content, SOC content, or annual N_2O emissions). The PBM must be peer reviewed in at least three scientific publications. The PBMs indicated above meet the requirement on the scientific publications. In addition, the project proponents must develop an objective and unambiguous operating procedure to parameterize and run the PBMs. This procedure document must spell out how every input parameter shall be set. The applicability of the selected model is dependent on the soil type(s), climate, and broad management of the area in which the model is applied. Therefore, it is required to (1) validate the model for the conditions of the Project Parcels, and (2) specify the conditions under which the model's operating procedures remain valid. The validation of a model shall be conducted by comparing field measurements to model predictions. Once model validation has been completed, it does not need to be repeated.

The nature of geographic variability in conditions requires that some degree of judgment to be left to the model validator in order to determine the number of field measurement that will be adequate for local circumstances. Heterogeneous conditions may require more samples, while flatter or otherwise homogenous scenarios may require fewer.

The slope of the relation between modeled and measured values shall be between 0.9 and 1.1 as tested using two one-sided t-tests using a significance of 90%.

[17] Daycent is a version of the Century model with a daily time step, and these two models are essentially the same if it comes to simulating SOC. However, DAYCENT can also simulate soil N_2O and CH_4 emissions whereas Century cannot.

STRUCTURAL UNCERTAINTY FOR PBMs

For PBMs, the structural uncertainty for soil C sequestration shall be calculated as the half-width of the 90% confidence interval around the mean deviation between modeled and measured differences between baseline and project SOC quantities, multiplied by 44/12 to convert the uncertainty into CO_2-equivalents, as is commonly done in GHG accounting methodologies. This uncertainty shall be noted and subtracted from the final ERTs, as explained in Section D.4. An uncertainty for N_2O emissions shall be calculated similarly as the half-width of the 90% confidence interval around the mean deviation between modeled and measured differences of project N_2O emissions, except for a multiplication with 310 x 44 / 28, to account for the radiative forcing and molecular weight of N_2O.

INPUT UNCERTAINTY FOR PBMs

The input uncertainty for PBMs shall be calculated using a Monte Carlo analysis based on a multivariate distribution of the input parameters. At least 200 different draws out of this multivariate distribution for both the Baseline Scenario and the Project Scenario and subsequent model simulations must be executed. For each of the draws of the distribution, one emission reduction is calculated by subtracting the Baseline emissions from the Project emissions. Calculate the uncertainty as the value corresponding to the 10% quantile for the distribution of values.

D.2 Baseline Emissions

D.2.1 General Equation

If avoided landfill emissions are claimed by the project, the emissions of the waste material when deposited in a landfill must be calculated for each project parcel separately using the following equations:

[EQ 1]

$$BE(y,i) = f_{diverted}(BE_{landfill}(y,i)) + BE_{\Delta SOC}(y,i) + BE_{N2O}(y,i)$$

Sub-equations for Components:

[EQ 2]

$$BE_{landfill,}(y,i) = BE_{landfill.CH4} - \left(\frac{\sum_{i=1}^{j} W_j \cdot DOC_j \cdot DOC_f}{40} \cdot \frac{44}{12}\right)$$

[EQ 3]

$$BE_{\Delta SOC}(y,i) = A(i) \cdot \Delta SOC(y,i) \cdot \frac{44}{12}$$

[EQ 4]

$$BE_{N2O}(y,i) = A(i) \cdot CE_{N2O}(y,i)$$

Where:

$BE(y,i)$	=	The total sum of the baseline emissions associated with project parcel i during year y. See EQ 1 above. [MT CO_2-eq yr^{-1}]
$f_{diverted}$	=	The percentage of the waste source that is additional. See Section C.1.1.
$BE_{landfill}(y,i)$	=	The cumulative baseline emissions of Methane and Carbon Dioxide from waste material at the landfill under the baseline scenario during year y. To be set to 0 when emission reductions at the landfill claimed by an entity other than the Project Proponents. See EQ 2 above. [MT CO_2-eq yr^{-1}]
$BE_{landfil,CH4}(y,i)$	=	The cumulative baseline Methane emissions from waste material at the landfill or waste storage pond under the baseline scenario during year y. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents. [MT CO_2-eq yr^{-1}]
W_j	=	Amount of organic waste type j prevented from disposal, expressed as dry mass. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
DOC_j	=	Fraction of waste type *j* that is degradable organic carbon (by weight). To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
DOC_f	=	Fraction of degradable organic carbon (DOC) that fully decomposes to CO_2. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
$\frac{44}{12}$	=	Factor to convert the mass of C to CO_2.
$BE_{\Delta SOC}(y,i)$	=	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the baseline scenario, calculated using a model that

meets the requirements of Section D.1. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO_2 or negative when it is net sink of CO_2. See EQ 3 above. [MT CO_2-eq yr^{-1}]

$A(i)$ = Size of project parcel i. [ha]

$\Delta SOC(y,i)$ = Change in baseline soil organic carbon of project parcel i during year y of the baseline scenario, calculated using a model that meets the requirements of Section D.1. [MT C ha^{-1} yr^{-1}]

$BE_{N2O}(y,i)$ = Cumulative baseline Nitrous Oxide emissions from soils of the project parcel i during year y of the baseline scenario, expressed in CO_2-eq. To be calculated using a model that meets the requirements of Section D.1. See EQ 4 above. [MT CO_2-eq yr^{-1}]

$CE_{N2O}(y,i)$ = Annual N_2O emissions rate from soils of project parcel i during year y of the baseline scenario. To be calculated using a model that meets the requirements of Section D.1. [MT CO_2-eq ha^{-1} yr^{-1}]

Note that the "44/12" factor converts a mass of carbon into a mass of Carbon Dioxide. In addition, the quantity $W_j \cdot DOC_j \cdot DOC_f$ represents the cumulative mass of carbon that is decomposed after 40 years in a landfill for waste material. Therefore, $\frac{44}{12}\frac{\sum_{i=1}^{j} W_j \cdot DOC_j \cdot DOC_f}{40}$ represents the annual CO_2 emissions from decomposition of the waste material in the landfill under the baseline scenario.

D.2.2 Quantification Procedure

The value $BE_{landfill,CH4}(y,i)$ shall be calculated as the quantity $BE_{CH4,SWDS,y}$ using the CDM tool "Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site." The quantities W_j, DOC_j, and DOC_f shall be set according to this CDM tool. Finally, the quantity $BE_{\Delta SOC}(y,i)$ shall be calculated using a model that meets the requirements of Section D.1.

D.3 Project Emissions

D.3.1 General Equation

[EQ 5]

$$PE(y,i) = PE_{\Delta SOC}(y,i) + PE_{N2O}(y,i) + PE_{fuel}(y,i) + PE_{compost,CH4}(y,i)$$

Sub-Equations for Components

[EQ 6]

$$PE_{\Delta SOC}(y,i) = A(i) \cdot \left(\frac{\Delta SOC_d(40)}{40} + \Delta SOC_i(y,i) \right) \cdot \frac{44}{12}$$

[EQ 7]

$$PE_{N2O}(y,i) = A(i) \cdot CE_{N2O}(y,i)$$

Where:

$PE(y,i)$	=	The total sum of the project emissions during year y. [MT CO_2-eq yr^{-1}]
$PE_{\Delta SOC}(y,i)$	=	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the project, calculated using a model that meets the requirements of Section D.1. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO2 or negative when it is net sink of CO_2. See EQ 6 above. [MT CO_2-eq yr^{-1}]
$A(i) \cdot$	=	Size of project parcel i. [ha]
$\Delta SOC_d(40)$	=	Change in carbon from added compost remaining in the soil at year 40. To be calculated using a model that meets the requirements of Section D.1 [MT C ha^{-1} yr^{-1}]
$\Delta SOC_i(y,i)$	=	Annual indirect change in soil carbon due to increases in plant productivity during year. To be calculated using a model that meets the requirements of Section D.1. [MT C ha^{-1} yr^{-1}]
$\frac{44}{12}$	=	Factor to convert the mass of C to CO_2.
$CE_{N2O}(y,i)$	=	Cumulative Nitrous Oxide emissions from soils of the project parcel i during year y of the project, expressed in CO_2-eq. To be calculated using a model that meets the requirements of Section D.1. See EQ 7 above. [MT CO_2-eq yr^{-1}]
$PE_{N2O}(y,i)$		Annual N_2O emissions rate from soils of project parcel i during year y of the project. To be calculated using a model that meets the requirements of Section D.1. [MT CO_2-eq ha^{-1} yr^{-1}]
$PE_{fuel}(y,i)$	=	Fuel emissions from transportation to the project parcel and application of the organic material on the land during year y. [MT CO_2-

eq yr^{-1}]

$PE_{compost,CH4}(y,i)$ = At a year when compost is added, e.g., when $y = 1$, the Methane emissions emitted during composting of the organic material, expressed in CO_2-eq. At all other years, this quantity is to be set to 0. When emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents, this quantity is to be set to 0 at all times to avoid double discounting [MT CO_2-eq yr^{-1}]

Because $\Delta SOC_d(40)$ represents the compost carbon remaining after 40 years, $\frac{\Delta SOC_d(40)}{40}$ represents the fraction of the compost carbon remaining that can be claimed as a GHG benefit for every year of the project period.

D.3.2 Quantification Procedure

The quantities $\Delta SOC_d(40)$, $\Delta SOC_i(y)$, and $PE_{N2O}(i,y)$ shall be calculated using a Tier-2 Empirical Model, or a PBM. If a PBM is used that is based on conceptual C-pools, only pools that have a turnover time of greater than 2 years shall be counted towards $\Delta SOC_d(40)$ and $\Delta SOC_i(y)$. This provision is included to avoid incorporating carbon sources that are readily decomposable as carbon sequestration. $\Delta SOC_d 40$ and $\Delta SOC_i(y)$ must be *reduced* by an appropriate discounting factor, while $PE_{N2O}(i,y)$ must be increased by an appropriate discounting factor, as specified in Section D.1.

$PE_{fuel}(i,y)$ is the sum of the emissions from fuel use from transportation and the fuel use from application of the compost. The fuel use from transportation of the compost shall be calculated using the CDM tool "Project and leakage emissions from road transportation of freight." The fuel use from application of the compost shall be calculated using the CDM tool "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion."

The project proponent must account for any increase in enteric emissions associated with the project activity, likely due to an increased stocking rate. The ACR Tool for Tier I Estimation of Emissions from Livestock Management Projects shall be used to calculate the net enteric emissions. The project proponent must enter all baseline and project scenario data required by the "2. Enteric" tab in the tool (all other data input tabs can be excluded). The value for the net emissions from Enteric shall be pulled from cell J13 of the "6. X-ANTE" tab and included in equation 8 below. If the result is a positive number (emission reductions), it will be considered "zero" for the purposes of conservativeness.

$PE_{compost,CH4}(i)$ shall be calculated using the most recent default emission factor available from the IPCC for the CH_4 emissions from biological treatment of waste.[18]

[18] As of the writing of this methodology, the emissions factor is found in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5: Waste, Chapter 4: Biological Treatment of Solid Waste.

D.4 Summary of GHG Emission Reduction and/or Removals

[EQ 8]

$$ER_y = \sum_{i=1}^{nrParcels} \left(PE(y,i) - BE(y,i)\right) + \Delta CH_4 enteric - u_{total}$$

Where:

ER_y	=	GHG emissions reductions and/or removals in year y [tCO_2-eq yr^{-1}]
$nrParcels$	=	Number of individual Project Parcels
$PE(y,i)$	=	Project emissions in year y for individual parcel i [$MTCO_2$-eq yr^{-1}]
$BE(y,i)$	=	Baseline emissions in year y for individual parcel i [$MTCO_2$-eq yr^{-1}]
$\Delta CH_4 enteric$	=	Enteric emissions associated with an increase in stocking rate over each project parcel. Either enter zero, or the value from cell J13 of the 6.T-XANTE tab of the *ACR Tool for Estimation of Emissions from Livestock Management Projects*, whichever is less. [$MTCO_2$-eq yr^{-1}]
u_{total}	=	Total uncertainty deduction [MT CO_2-eq]

D.5 Leakage

Emissions leakage refers to instances where activities to reduce emissions from a project parcel may result in increased emissions due to activities and market shifts occurring at locations beyond the project boundaries. Available field research suggests that the addition of compost to grasslands will generally increase soil carbon and the production of forage for livestock. Although not directly connected to the project activities, increases or decreases in stocking rate have been accounted for in this methodology in the spirit of whole-system accounting and conservativeness.

Voluntary and significant stocking rate reductions (more than three percent of the baseline) will make the project ineligible for crediting over the quantification period, until the stocking rate has returned to within -3% of the baseline level. Monitoring and reporting would be required to continue to ensure permanence of sequestered carbon. A leakage deduction will not need to be taken for any stocking rate reductions of greater than 3% from the baseline if justifiably attributable to verifiable instances of natural disaster, disease or otherwise that significantly reduces the stocking rates involuntarily. These circumstances must be verified by an accredited VVB with sufficient documentation including an attestation by the Proponent, demonstrating that this circumstance would have also affected the baseline in a business as usual situation.

E. Monitoring

E.1 Data and Parameters Available at Validation

Various data elements related to compost, soil, weather, and management must be available at model validation. The specific data elements required are detailed below, and explicitly outlined in Appendix A.

- **Compost**. The following data must be available for each batch of compost. Unless sound data for these parameters are available (e.g., as a result from a certification), the compost must undergo laboratory tests.
    - The **carbon concentration** is required to convert mass of dry compost to mass of carbon added, which is a property that is required by a model.
    - The **nitrogen concentration** is required to convert mass of dry compost to mass of nitrogen added, which is needed to verify the applicability conditions and may also be required for the model used.
    - The **C:N ratio** is required to be calculated based on the aforementioned data availability.
    - It is advised, but not required, to include the **phosphorus concentration** in the elemental analysis, as this may improve the models' ability to simulate changes in SOC related to compost addition.
    - The **bulk density** is required to convert a volume of compost, a very common unit used by compost facilities, spreaders, and transporters, into a mass of compost.
    - The **moisture content** is required to convert a mass of moist compost into dry compost.
    - The **pH** of the compost must be measured and recorded

  In addition, the following information shall be obtained if available:
    - Source of the compost raw materials
    - Fate of the organic matter under baseline conditions
- **Soil**. At least three soil samples per parcel shall be taken within each stratum representing at least 0-20 cm. If the relative standard error among the three samples is greater than 20%, more samples shall be taken until the relative standard error is less than 20%. Project developers may choose to take more and deeper samples than this minimum requirement, which is beneficial in improving both model runs and the potential for demonstrating carbon sequestration at greater depths. Samples shall not be composited. The following measurements shall be conducted on the soil samples based on standard analytical protocols described in the Soil Science Society of America Methods of Soil Analysis (Sparks et al. 1996):
    - Total soil carbon
    - Soil texture
    - Soil bulk density
    - Soil pH

  Note that the project developer is allowed to measure the soil carbon at the start of the project *after* compost application on reference locations within the Project Parcels that did not receive

the compost application. The latter is feasible when reference locations are shielded from compost application by putting a tarp at that location and removing the compost that is deposited on the tarp before soil carbon analysis.

- **Historical weather**. Daily minimum and maximum temperatures and rainfall shall be obtained for a period of five years before the start of the Project. Historical weather data must come from the nearest weather station or other published weather records (such as Daymet).
- **Project weather**. Daily minimum and maximum temperatures and rainfall shall be obtained through the duration of the Project. This data must come from the nearest weather station or other published weather records (such as Daymet).
- **Historical management**. The following parameters shall be provided for each stratum for a period of at least 5 years before the start of the project. Additional years of data are highly recommended if significant changes in land cover or management are known to have occurred
    - Stocking rates
    - Stocking periods
    - Incidence of fires
- **Project management**. The following parameters shall be provided for each stratum of a project
    - Project population
    - Stocking rate
    - Stocking period
    - Average stocking rate (average over all project years)
    - Minimum stocking rate
    - Maximum stocking rate
    - Incidence of fires
- **Plants and plant communities**. A land assessment by a Qualified Expert must be provided that this consistent with standard NRCS ecological site descriptions[19]. This land assessment report should include a stratification of the land and a description of plant productivity (which is inclusive of species type and forage quality) into three groups: “poor”, “medium”, or “high”. Values of net primary productivity are required in order to better determine yield response.. These values should be obtained through the creation of an exclusion area where livestock are not able to graze so that primary productivity can be measured in dry matter/unit area. The land assessment report shall contain a broad description of the plant communities, percentage cover of natives as well as any problems with invasive weeds before the start of the project. Finally, the land assessment report shall also contain an assessment of the fire risk.

In addition to the parameters described above, various additional soil and site parameters may be needed to parameterize the model runs. The onus is on the project developer to demonstrate that a model was used and parameterized correctly.

[19] Information on NRCS ecological site descriptions may be found online at http://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/ecoscience/desc/

E.2 Data and Parameters Recorded during Compost Application

In addition, a description of the application procedure must be provided. This description must include:

- Application date
- Machinery used
- Application method
- Broadcast rate (tons/ha)
- Rationale for application procedure and reference source if available

Receipts of compost purchase, transportation, and application shall be kept and made available to the validator. In addition, it is strongly recommended to take pictures during the application of the compost. All data collected as part of monitoring must be archived electronically and be kept at least for two years after the end of the project crediting period.

E.3 Data and Parameters Monitored after Compost Application

Total soil carbon, texture, bulk density and pH shall be measured for the 0-20cm soil depth at the start of the project and at least every 10 years thereafter as described in Section E.1. In addition, an update of the land assessment report by a Qualified Expert shall be conducted two and five years after compost application.

Actual weather shall be recorded from the same weather station used during model validation. In addition, Stocking Rates and periods shall be provided for each stratum for every year after the start of the project. Every incidence of wildfire shall be reported and used in ex-post simulation, if the selected model allows.

E.4 Updating Models and Model Structural Uncertainty Deduction

The model uncertainty must be updated at least every 10 years, which is also the time frame of a project's crediting period extension. However, it is allowed to update a model's structural uncertainty deductions more frequently as new field data becomes available during a project's crediting period. The new structural uncertainty deductions must be proposed in a monitoring report and explicitly approved by a VVB before ERTs are issued using the new structural uncertainty deductions. The calculation of Baseline and Project emissions must always use the same structural uncertainty deductions.

In addition to updating the structural uncertainty deduction, it is allowed to use (a) different model(s) after the start of the project. For example, it is allowed to switch from a Tier-2 Empirical Model to a PBM. All requirements related to the selection of the model(s) and the calculation of its/their structural uncertainty deduction must be met. This switch must be proposed in a monitoring report and explicitly approved by a VVB before ERTs are issued using the new model(s). The calculation of Baseline and Project emissions must always use the same modeling approach.

F. Permanence

Projects must be consistent with the ACR Standards for permanence, which require proponents to sign ACR's risk mitigation agreement.[20] This risk mitigation agreement legally requires the project proponents to conduct a risk assessment using the latest ACR-approved Non-Permanence Risk Analysis and Buffer Determination tool[21]. The result of this assessment is an overall risk category for the project, translating into a percentage or number of ERTs that the project proponent must deposit, at each new ERT issuance, into a shared non-permanence buffer pool managed by ACR. For instance, ERTs contributed from the Project or those purchased from other Projects may be used to satisfy this buffer pool requirement. Alternatively, the proponent may also meet its legal obligations by providing evidence of sufficient insurance coverage with an ACR-approved insurance product. Reversals need only be fully compensated when they occur during the period in which monitoring is required (i.e. during the minimum project term).

In addition, the proponent shall take measures to reduce the risk of reversal from the following types of reversals that may occur, namely inundation, land use conversion and tillage. Every incidence of inundation due to extensive rainfall or large scale flooding of rivers and streams that lasts for longer than two months in a given crediting year shall be reported. All areas that were inundated for longer than two months shall be excluded from crediting during that year. It is likely that the boundaries of the flooded area do not coincide with the boundaries of strata established during stratification. Therefore, the flooded areas shall be cut out from existing strata for the duration of the year during which the flood happened. If the flood straddles a crediting year, ERTs may not be generated for both years during which the flood occurred. Unless specific circumstances indicate that that the Project Proponent flooded the parcel intentionally, inundation shall be considered a non-intentional reversal according to terms of the risk mitigation agreement.

Any conversion of a project parcel to any other land use than Grazed Grassland, such as annual arable crops or development, will immediately exclude this parcel from generating future ERTs. Unless the soil carbon loss due to the conversion on this Project Parcel is duly replaced by acquiring ERTs from this or other projects and project types, all ERTs from previously stored soil carbon shall be considered a reversal of previously credited ERTs. In addition to the aforementioned risk mitigation mechanisms discussed above, the project proponent may replace the reversed ERTs with ERTs issued from other project parcels within the same project within two years of the date of the conversion. Note that even after replacing the ERTs lost to conversion, the project parcel that was converted must be permanently excluded from issuing ERTs. All other Project Parcels within the Project are not affected by one project

[20] The current version of the ACR Standard can be found online at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

[21] The Tool for AFOLU Non-Permanence Risk Analysis and Buffer Determination can be found online at http://www.v-c-s.org/sites/v-c-s.org/files/Tool%20for%20AFOLU%20Non-Permanence%20Risk%20Analysis%20and%20Buffer%20Determination.pdf

parcel being converted to another land-use. In case only part of a parcel was converted to another land use, it is allowed to pro-rate the reversed ERTs or re-purchase ERTs based on the relative proportion of the conversion within the parcel. Land use conversion shall be considered an intentional reversal according to terms of the risk mitigation agreement.

In the unlikely case that a tillage event occurs on the Project Parcel without a conversion of the grassland to agricultural or any other land use, all soil carbon ERTs previously issued from this Project Parcel will be considered to have been reversed unless the carbon losses resulting from the tillage event on the Project Parcel are duly accounted for and compensated by retiring existing ERTs from the current or other projects and project types. Similarly to land conversions, this carbon loss shall be verified in a monitoring report and must be verified by a VVB. In addition, unless such a true-up occurs, the project parcel shall be permanently excluded from issuing ERTs. Tillage shall be considered an intentional reversal according to terms of the risk mitigation agreement.

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G.1 Sources

This methodology has adopted aspects of the following sources for its carbon accounting:

- ACR's Grazing Land and Livestock Management (GLLM) Methodology, available at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/grazing-land-and-livestock-management-gllm-ghg-methodology
- "Adoption of sustainable agricultural land management (SALM)," available at http://www.v-c-s.org/sites/v-c-s.org/files/SALM%20Methodolgy%20V5%202011_02%20-14_accepted%20SCS.pdf, submitted to and approved by the Verified Carbon Standard (VCS); developed by the World Bank's BioCarbon fund
- Clean Development Mechanism (CDM) "Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site," available at http://cdm.unfccc.int/EB/041/eb41_repan10.pdf
- CDM tool "Project and leakage emissions from road transportation of freight," available at http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-12-v1.pdf
- CDM "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion," available at http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-03-v2.pdf
- "Organic Waste Composting Project Protocol," (Version 1.0), available at http://www.climateactionreserve.org/how/protocols/organic-waste-composting/, approved for use under the Climate Action Reserve.

Appendix A: Parameter List

A.1 Parameters for Baseline and Project Emissions, and Overall Emissions Reductions and/or Removals Quantification

Parameter	$BE(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Sum of baseline emissions associated with project parcel *i* during year *y*
Relevant Section	D.2, D.4
Relevant Equation(s)	1, 8
Source of Data	Calculated in equation 1
Data Requirements	$BE_{landfill}(y,i)$, $BE_{landfill,CH4}(y,i)$, $BE_{\Delta SOC}(y,i)$
Collection Procedure	Based on calculations from equations 2, 3, and 4
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$f_{diverted}$
Units	%
Description	The percentage of the waste source that is additional
Relevant Section	C.1.1, C.1.2, D.4
Relevant Equation(s)	1
Source of Data	Determination through 8.1.1
Data Requirements	Compost source materials and additionality
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility.
Comments	

Parameter	$BE_{landfill}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	The cumulative baseline emissions of Methane and Carbon Dioxide from waste material at the landfill under the baseline scenario during year y
Relevant Section	D.2
Relevant Equation(s)	1, 2
Source of Data	Calculated in equation 2
Data Requirements	$BE_{landfill.CH4}$, W_j, DOC_j , DOC_f
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions at the landfill claimed by an entity other than the Project Proponents

Parameter	$BE_{landfill,CH4}(y,i)$
Units	MT CO_2-eq yr^{-1}

Description	The cumulative baseline Methane emissions from waste material at the landfill or waste storage pond under the baseline scenario during year y
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Quantity $BE_{CH4,SWDS,y}$ using the CDM tool "Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site"
Data Requirements	W_j and IPCC factors
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	W_j
Units	Tons of dry mass
Description	Amount of organic waste type j prevented from disposal, expressed as dry mass
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Uncomposted organic waste diverted from landfill
Data Requirements	Tons and type of organic waste prevented from disposal
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	DOC_j
Units	%
Description	Fraction of waste type *j* that is degradable organic carbon (by weight)
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Characteristics of waste type *j*
Data Requirements	Fraction of degradable organic carbon(by weight) in the waste type *j*
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	DOC_f
Units	%
Description	Fraction of degradable organic carbon (DOC) that fully decomposes to CO_2.
Relevant Section	D.2

Relevant Equation(s)	2
Source of Data	Characteristics of DOC
Data Requirements	W_j and amount of DOC in compost that fully decomposes to CO_2.
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	$BE_{\Delta SOC}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the baseline scenario. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO_2 or negative when it is net sink of CO_2.
Relevant Section	D.2
Relevant Equation(s)	3
Source of Data	Model estimates
Data Requirements	$A(i)$, $\Delta SOC(y,i)$
Collection Procedure	Calculated from equation 3
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$A(i)$
Units	hectares
Description	Size of project parcel i
Relevant Section	D.2, D.3
Relevant Equation(s)	2, 6, 7
Source of Data	Project Proponent records
Data Requirements	Coordinates and area of project parcels
Collection Procedure	Project Proponents will collect and record area of participating project parcels.
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$\Delta SOC(y,i)$
Units	MT C ha^{-1} yr^{-1}
Description	Change in baseline soil organic carbon of project parcel i during year y of the baseline scenario
Relevant Section	D.2
Relevant Equation(s)	3
Source of Data	
Data Requirements	
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1.
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$BE_{N2O}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Cumulative baseline Nitrous Oxide emissions from soils of the project parcel i during year y of the baseline scenario, expressed in CO_2-eq.
Relevant Section	D.2
Relevant Equation(s)	4
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $CE_{N2O}(y,i)$
Collection Procedure	Calculated from equation 4
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$CE_{N2O}(y,i)$
Units	MT CO_2-eq ha^{-1} yr^{-1}
Description	Annual N_2O emissions rate from soils of project parcel i during year y of the baseline scenario.
Relevant Section	D.2
Relevant Equation(s)	4
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$PE(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	The total sum of the project emissions during year y
Relevant Section	D.3
Relevant Equation(s)	6, 8
Source of Data	Calculated in equation 5
Data Requirements	$PE_{\Delta SOC}(y,i)$, $PE_{N2O}(y,i)$, $PE_{fuel}(y,i)$, $PE_{compost,CH4}(y,i)$
Collection Procedure	Based on calculations from equations 6 and 7
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{\Delta SOC}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Annual CO_2 emissions from the change in soil organic C for project parcel *i* during year *y* of the project
Relevant Section	D.3
Relevant Equation(s)	5, 6
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $\Delta SOC_d(40)$, $\Delta SOC_i(y,i)$

Collection Procedure	Calculated in equation 6
Revision Frequency	Project year (annually)
Comments	The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO2 or negative when it is net sink of CO_2.

Parameter	$\Delta SOC_d(40)$
Units	MT C ha^{-1} yr^{-1}
Description	Change in carbon from added compost remaining in the soil at year 40
Relevant Section	D.3
Relevant Equation(s)	6
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1.
Revision Frequency	Project year (annually)
Comments	

Parameter	$\Delta SOC_i(y,i)$
Units	MT C ha^{-1} yr^{-1}
Description	Annual indirect change in soil carbon due to increases in plant productivity during year.
Relevant Section	D.3
Relevant Equation(s)	6
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{N2O}(y,i)$
Units	MT CO_2-eq ha^{-1} yr^{-1}
Description	Annual N_2O emissions rate from soils of project parcel i during year y of the project.
Relevant Section	D.3
Relevant Equation(s)	5, 7
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $CE_{N2O}(y,i)$
Collection Procedure	Calculated in equation 7
Revision Frequency	Project year (annually)
Comments	
Parameter	$CE_{N2O}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Cumulative Nitrous Oxide emissions from soils of the project parcel i during year y of the project, expressed in CO_2-eq.
Relevant Section	D.3

Relevant Equation(s)	7
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{fuel}(y, i)$
Units	MT CO_2-eq yr^{-1}
Description	Sum of fuel emissions from transportation to the project parcel and application of the organic material on the land during year y.
Relevant Section	D.3
Relevant Equation(s)	5
Source of Data	Calculated using CDM tool "Project and leakage emissions from road transportation of freight" and CDM tool "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion"
Data Requirements	Quantity and type of fuel consumed and combusted during transportation and application of compost
Collection Procedure	Project Proponent records from transportation and/or compost application receipts
Revision Frequency	Project year when compost is added
Comments	

Parameter	$PE_{compost,CH4}(y, i)$
Units	MT CO_2-eq yr^{-1}
Description	At a year when compost is added, e.g., when $y = 1$, the Methane emissions emitted during composting of the organic material, expressed in CO_2-eq. At all other years, this quantity is to be set to 0. When emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents, this quantity is to be set to 0 at all times to avoid double discounting.
Relevant Section	D.3
Relevant Equation(s)	5
Source of Data	Calculated the most recent emission factor available from the IPCC.
Data Requirements	kg of dry weight organic waste, factor to convert g CH4 to MT CO_2-eq
Collection Procedure	
Revision Frequency	Project year when compost is added
Comments	

Parameter	ER_y
Units	tCO_2-eq yr^{-1}
Description	GHG emissions reductions and/or removals in year y
Relevant Section	D.4
Relevant Equation(s)	8
Source of Data	Calculated in equation 8

Data Requirements	$nrParcels$, $PE(y,i)$, $BE(y,i)$, $CH_4enteric$
Collection Procedure	Based on Project Proponent records, as well as calculations from equations 1 and 5.
Revision Frequency	Project year (annually)
Comments	

Parameter	$nrParcels$
Units	#
Description	Number of project parcels
Relevant Section	D.4
Relevant Equation(s)	8
Source of Data	Project Proponent records
Data Requirements	Parcels participating in the project
Collection Procedure	Counting parcels participating in project
Revision Frequency	For each change in number of project parcel participating- revised before each new crediting period
Comments	

Parameter	$CH_4enteric$
Units	$MTCO_2$-eq yr^{-1}
Description	Enteric emissions associated with an increase in stocking rate over each project parcel.
Relevant Section	D.3, D.4
Relevant Equation(s)	8
Source of Data	Either a value of zero, or the value from cell J13 of the 6.T-XANTE tab of the *ACR Tool for Estimation of Emissions from Livestock Management Projects*, whichever is less.
Data Requirements	Grazing ruminant population, feeding situation (i.e. grazing or not grazing), percentage imported feed vs. grazing, mean daily temperature during winter
Collection Procedure	Project Proponent records
Revision Frequency	Data collected monthly and parameter revised each project year (annually)
Comments	

A.2 Other Project Data Required for Validation

Parameter	$compost$
Units	Multiple
Description	Analysis every time of compost applied
Relevant Section	E
Relevant Equation(s)	
Source of Data	Project Proponent records (from certification or from laboratory test results)
Data Requirements	Carbon concentration, nitrogen concentration, C:N ratio, bulk density, moisture content, pH, phosphorus concentration (optional), source of compost raw

	materials (optional), fate of organic matter under baseline conditions (optional)
Collection Procedure	Project Proponent reports from records
Revision Frequency	Every time compost is applied throughout project
Comments	

Parameter	$soil$
Units	Multiple
Description	Analysis for each stratum representing at least 0-20cm both before and after compost application for baseline and project calculations
Relevant Section	E
Relevant Equation(s)	
Source of Data	Laboratory test results
Data Requirements	Total soil carbon, soil texture, soil bulk density, soil pH
Collection Procedure	Project Proponent collects soil samples submits for analysis
Revision Frequency	Once at the beginning of project and again after the compost application, then at least every 10 years thereafter
Comments	

Parameter	$historical\ weather$
Units	Multiple (degrees, inches)
Description	Characterizes important weather and climate characteristics for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Weather station or other published weather records
Data Requirements	Daily minimum and maximum temperatures, rainfall
Collection Procedure	Project Proponent uses nearest weather station to project or other published weather records (such as Daymet) for use in model
Revision Frequency	Once at the beginning of project to establish a baseline
Comments	

Parameter	$project\ weather$
Units	Multiple (degrees, inches)
Description	Characterizes important weather and climate characteristics for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Weather station or other published weather records used for historical weather
Data Requirements	Daily minimum and maximum temperatures, rainfall
Collection Procedure	Project Proponent uses nearest weather station to project or other published weather records (such as Daymet) for use in model
Revision Frequency	Project year (annually)
Comments	

Parameter	$historical\ management$
Units	Multiple
Description	Historical grazing practices on Project Proponent's land

Relevant Section	C
Relevant Equation(s)	
Source of Data	Project Proponent records
Data Requirements	Stocking period (averaged over at least 3 of past 5 years), stocking rate(averaged over at least 3 of past 5 years), incidence of fires
Collection Procedure	Project Proponent records
Revision Frequency	When setting baseline
Comments	

Parameter	$project\ management$
Units	Multiple
Description	Grazing practices throughout project
Relevant Section	
Relevant Equation(s)	
Source of Data	Project Proponent records
Data Requirements	Project population, stocking period, average stocking rate(averaged over the years), minimum stocking rate, maximum stocking rate, incidence of fires
Collection Procedure	Project Proponent reports from records
Revision Frequency	Project year (annually)
Comments	

Parameter	*Plants and plant communities*
Units	Multiple
Description	Characterizes important plant communities present for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Project parcels (Land assessment by a Qualified Expert, consistent with standard NRCS ecological site descriptions)
Data Requirements	Stratification of land, description of plant productivity (species type and forage quality), broad description of plant communities, percentage cover of native plants, indication of any problems with invasive weeds, assessment of fire risk)
Collection Procedure	Land assessment by a Qualified Expert, consistent with standard NRCS ecological site descriptions
Revision Frequency	Once at the beginning of project and at year 2 and year 5 after compost application
Comments	

Parameter	*Compost application*
Units	Multiple
Description	Description of application procedure
Relevant Section	E
Relevant Equation(s)	
Source of Data	
Data Requirements	Application date, machinery used, application method, broadcast rate (tons/ha), rationale for application procedure and reference source (if

	available), receipts of compost purchase, transportation, and application, pictures during application (optional)
Collection Procedure	Collected during compost application
Revision Frequency	Every time compost is applied throughout project
Comments	All data collected as part of monitoring must be archived electronically and be kept at least for two years after the end of the project crediting period.



The American Carbon Registry™

Improved Forest Management Methodology for Quantifying GHG Removals and Emission Reductions through Increased Forest Carbon Sequestration on Non-Federal U.S. Forestlands

Version 1.3

April 2018

Methodology developed by Columbia Carbon, LLC

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This methodology was drafted by Matt Delaney and David Ford of L&C Carbon, based in Salem, Oregon, and Greg Latta of Oregon State University, based in Corvallis, Oregon. The methodology was approved by ACR through the public consultation and scientific peer review process.

A. METHODOLOGY DESCRIPTION

A1. SCOPE AND DEFINITIONS

This methodology is designed to quantify GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline forest management practices. Removals are quantified for increased sequestration through retention of annual forest growth when project activities exceed the baseline.

Baseline determination is project-specific and must describe the harvesting scenario that would maximize net present value (NPV) of perpetual wood products harvests per the assumptions as described in section C1, where various discount rates for different land ownership classes are used as proxies for the multiple forest management objectives typical of each owner class eligible under this methodology.

Project Proponents must demonstrate there is no activity-shifting leakage above the *de minimis* threshold. Market leakage must be assessed and accounted for in the quantification of net project benefits.

Definitions and Acronyms

ACR	American Carbon Registry
ATFS	American Tree Farm System
Activity Shifting Leakage	Increases in harvest levels on non-project lands owned or under management control of the project area timber rights owner
Baseline Management	Scenario in the absence of project activities
Carrying Costs	Property taxes, mortgage interest, and insurance premiums
Crediting Period	The period of time in which the baseline is considered to be valid and project activities are eligible to generate ERTs
De minimis	Threshold of 3% of the final calculation of emission reductions or removals
CO_2	Carbon Dioxide. All pools and emissions in this methodology are represented by either CO_2 or CO_2 equivalents. Biomass is converted to carbon by multiplying by 0.5 and then to CO_2 by multiplying by the molecular weight ratio of CO_2 to Carbon (3.664)
CO_2e	Carbon Dioxide equivalent. The amount of CO_2 that would have the same global warming potential (GWP) as other greenhouse

	gases over a 100-year lifetime using SAR-100 GWP values from the IPCC's fourth assessment report.
ERT	Emission Reduction Ton
Ex ante	Prior to project certification
Ex post	After the event, a measure of past performance
FSC	Forest Stewardship Council
Forestland	Forest land is defined as land at least 10 percent stocked by trees of any size, or land formerly having such tree cover, and not currently developed for non-forest uses. Land proposed for inclusion in this project area shall meet the stocking requirement, in aggregate, over the entire area
IFM	Improved Forest Management
IPCC	Intergovernmental Panel on Climate Change
Minimum Project Term	Time Period for which project activities must be maintained and monitored through third-party verification
Native Species	Trees listed as native to a particular region by the Native Plant Society, SAF Forestry Handbook, or State-adopted list
Net Present Value (NPV)	The difference between the present value of cash inflows and the present value of cash outflows over the life of the project
SFI	Sustainable Forestry Initiative
Timberlands	Forestlands managed for commercial timber production
Tree	A perennial woody plant with a diameter at breast height (4.5') greater than or equal to 1" and a height of greater than 4.5', with the capacity to attain a minimum diameter at breast height of 5" and a minimum height of 15' (shrub species are not eligible).
Ton	A unit of mass equal to 1000 kg
VCS	Verified Carbon Standard

A2. APPLICABILITY CONDITIONS

- This methodology is applicable only on non-federally owned forestland within the United States
- The methodology applies to lands that can be legally harvested by entities owning or controlling timber rights on forestland
- Private or non-governmental organization ownerships subject to commercial timber harvesting at the project Start Date in the with-project scenario must be certified by FSC, SFI, or ATFS or become certified within one year of the project Start Date. If there are no ongoing harvests at the project Start Date, but harvests occur later in the project life cycle, the project area must become certified before any commercial timber harvesting can occur
- All Tribal lands in the United States, except those lands that are managed or administered by the Bureau of Indian Affairs, are eligible under this methodology, provided that they meet ACR requirements for Tribal lands
- Public non-federal ownerships currently subject to commercial timber harvesting in the with-project scenario must:
    - be certified by FSC, SFI, or ATFS or become certified within one year of the project Start Date; *or*
    - have its forest management plan sanctioned by a by a senior government official within a state, or a state agency, or a federal agency
        - Please note that any such forest management plans must be updated at minimum every 10 years
    - If there are no ongoing harvests on a public non-federal ownership at the project Start Date, but harvests occur later in the project life cycle, the project area must become certified by FSC, SFI, or ATFS, or develop a sanctioned management plan before any commercial timber harvesting can occur
- Use of non-native species is prohibited where adequately stocked native stands were converted for forestry or other land uses after 1997
- Draining or flooding of wetlands is prohibited
- Project proponent must demonstrate its ownership or control of timber rights at the project start date
- The project must demonstrate an increase in on-site stocking levels above the baseline condition by the end of the Crediting Period

A3. POOLS AND SOURCES

Carbon pools	Included / Optional / Excluded	Justification / Explanation of choice
Above-ground biomass carbon	Included	Major carbon pool subjected to the project activity
Below-ground biomass carbon	Included	Major carbon pool subjected to the project activity
Standing dead wood	Included/Optional	Major carbon pool in unmanaged stands subjected to the project activity. Project Proponents may also elect to include the pool in managed stands. Where included, the

		pool must be estimated in both the baseline and with project cases.
Lying dead wood	Optional	Project Proponents may elect to include the pool. Where included, the pool must be estimated in both the baseline and with project cases.
Harvested wood products	Included	Major carbon pool subjected to the project activity
Litter / Forest Floor	Excluded	Changes in the litter pool are considered *de minimis* as a result of project implementation
Soil organic carbon	Excluded	Changes in the soil carbon pool are considered *de minimis* as a result of project implementation

Gas	Source	Included/ Excluded	Justification / Explanation of choice
CO_2	Burning of biomass	Excluded	However, carbon stock decreases due to burning are accounted as a carbon stock change
CH_4	Burning of biomass	Included	Non-CO_2 gas emitted from biomass burning
N_2O	Burning of biomass	Excluded	Potential emissions are negligibly small

Leakage Source		Included / Optional / Excluded	Justification / Explanation of choice
Activity-Shifting	Timber Harvesting	Excluded	Project Proponent must demonstrate no activity-shifting leakage beyond the *de minimis* threshold will occur as a result of project implementation
	Crops	Excluded	Forestlands eligible for this methodology do not produce agricultural crops that could cause activity shifting
	Livestock	Excluded	Grazing activities, if occurring in the baseline scenario, are assumed to continue at the same levels under the project scenario and thus there are no leakage impacts.
Market Effects	Timber	Included	Reductions in product outputs due to project activity may be compensated by other entities in the marketplace. Those emissions must be included in the quantification of project benefits.

A4. METHODOLOGY SUMMARY

This methodology is designed to quantify GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline forest management practices. Removals are quantified for increased sequestration through retention of annual forest growth when project activities exceed the baseline.

The IFM baseline is the legally permissible harvest scenario that would maximize net present value (NPV) of perpetual wood products harvests, used as a proxy for the multiple forest management objectives typical of each owner class eligible under this methodology. The baseline management scenario shall be based on silvicultural prescriptions recommended by published state or federal agencies to perpetuate existing onsite timber-producing species while fully utilizing available growing space.

In developing the baseline scenario, exceptions to the requirement that the baseline management scenario shall perpetuate existing onsite timber-producing species may be made where it can be demonstrated that a baseline management scenario involving replacement of existing onsite timber producing species (e.g. where forest is converted to plantations, replacing existing onsite timber-producing species) is feasible and has been implemented in the region within 10 years of the project start date. This shall be substantiated either by (1) demonstrating with management records that the baseline management scenario involving replacement of existing onsite timber producing species has been implemented within 10 years of the project start date on lands in the state containing the project area owned or managed by the project proponent (or by the previous project area owner/manager) or by (2) providing dated (from previous 10 years) aerial imagery that identifies at least two properties (of similar site conditions and forest type) in the state showing, first, the initial or existing onsite timber, and second, the replacement use (e.g. commercial plantation). The areas of forest conversion identified must have combined acreage equal to or greater than the annual acreage converted in the project baseline scenario. Published or written evidence that the baseline scenario (e.g., conversion of existing onsite timber) is common practice in the region (this can be a state or local forester, a consulting forester, an owner of a mill, etc.) must also be provided.

The resulting harvest schedule is used to establish baseline stocking levels through the Crediting Period.

This methodology is similar to a previously approved ACR IFM methodology developed by Finite Carbon Corporation[1] in that it quantifies GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline management practice levels.

The discount rate assumptions for calculating NPV vary by ownership class (see Table 1, Section C1) and include the 6% rate for private industrial timberlands from the earlier IFM methodology. Actual landowner discount rate assumptions are typically not publicized in the scientific literature and companies, individuals, and organizations by and large do not share the values they use. However,

[1] American Carbon Registry *Improved Forest Management Methodology for Quantifying GHG Removals and Emission Reductions through Increased Forest Carbon Sequestration on U.S. Timberlands.* September 2010.

approximate discount rates can be indirectly estimated by using forest economic theory and the age-class structure distribution of different U.S. forest ownership classes.

This methodology establishes an average baseline determination technique for all major forest ownership classes in the United States with the exception of federal lands. The appropriate ownership class is used to identify a project-specific NPV-maximizing baseline scenario as described in section C1. Project Proponents then design a project scenario for the purposes of increased carbon sequestration. The project scenario by definition will result in a lower NPV than the baseline scenario. Project Proponents use the baseline discount rate values for NPV maximization for the appropriate ownership class and run a project scenario for purposes of increased carbon sequestration. The difference between these two harvest forecasts are the basis for determining carbon impacts and ERTs attributable to the project.

B. ELIGIBILITY, BOUNDARIES, ADDITIONALITY, AND PERMANENCE

B1. PROJECT ELIGIBILITY

This methodology applies to non-federal U.S. forestlands that are able to document 1) clear land title or timber rights and 2) offsets title. Projects must also meet all other requirements of the *ACR Standard, Version 5.0*.

This methodology applies to lands that could be legally harvested by entities owning or controlling timber rights.

Proponents must demonstrate that the project area, in aggregate, meets the definition of Forestland provided in Section A1 above.

B2. PROJECT GEOGRAPHIC BOUNDARY

The Project Proponent must provide a detailed description of the geographic boundary of project activities. Note that the project activity may contain more than one discrete area of land, that each area must have a unique geographical identification, and that each area must meet the eligibility requirements. Information to delineate the project boundary must include:

- Project area delineated on USGS topographic map
- General location map
- Property parcel map

Aggregation of forest properties with multiple landowners is permitted under the methodology consistent with Chapter 6 of the *ACR Standard, Version 5.0* which provides guidelines for aggregating multiple landholdings into a single forest carbon project, as a means to reduce per-acre transaction costs of inventory and verification.

B3. PROJECT TEMPORAL BOUNDARY

Projects with a Start Date of November 1, 1997 or later are eligible[2]. The Start Date is when the Project Proponent began to apply the land management regime to increase carbon stocks and/or reduce emissions.

In accordance with the *ACR Standard, Version 5.0*, all projects will have a Crediting Period of twenty (20) years. The minimum Project Term is forty (40) years. The minimum Project Term begins on the Start Date (not the first or last year of crediting).

[2] American Carbon Registry (2018), *American Carbon Registry Standard, Version 5.0.* Winrock International, Little Rock, Arkansas.

If the project Start Date is more than one year before submission of the GHG plan, the Project Proponent shall provide evidence that GHG mitigation was seriously considered in the decision to proceed with the project activity. Evidence shall be based on official and/or legal documentation. Early actors undertaking voluntary activities to increase forest carbon sequestration prior to the release of this requirement may submit as evidence recorded conservation easements or other deed restrictions that affect onsite carbon stocks.

B4. ADDITIONALITY

Projects must apply a three-prong additionality test[3] to demonstrate that they exceed currently effective and enforced laws and regulations; exceed common practice in the forestry sector and geographic region; and face a financial implementation barrier.

The regulatory surplus test involves existing laws, regulations, statutes, legal rulings, or other regulatory frameworks that directly or indirectly affect GHG emissions associated with a project action or its baseline candidates, and which require technical, performance, or management actions. Voluntary guidelines are not considered in the regulatory surplus test.

The common practice test requires Project Proponents to evaluate the predominant forest industry technologies and practices in the project's geographic region. The Project Proponent shall demonstrate that the proposed project activity exceeds the common practice of similar landowners managing similar forests in the region. Projects initially deemed to go beyond common practice are considered to meet the requirement for the duration of their Crediting Period. If common practice adoption rates of a particular practice change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal, but does not affect its additionality during the current Crediting Period.

An implementation barrier represents any factor or consideration that would prevent the adoption of the practice/activity proposed by the Project Proponent. Financial barriers can include high costs, limited access to capital, or an internal rate of return in the absence of carbon revenues that is lower than the Proponent's established minimum acceptable rate. Financial barriers can also include high risks such as unproven technologies or business models, poor credit rating of project partners, and project failure risk. When applying the financial implementation barrier test, Project Proponents should include solid quantitative evidence such as NPV and Internal Rate of Return (IRR) calculations. The project must face capital constraints that carbon revenues can potentially address; or carbon funding is reasonably expected to incentivize the project's implementation; or carbon revenues must be a key element to maintaining the project action's ongoing economic viability after its implementation.[4]

B5. PERMANENCE

Project Proponents commit to a minimum Project Term of 40 years. Projects must have effective risk mitigation measures in place to compensate fully for any loss of sequestered carbon whether this occurs through an unforeseen natural disturbance or through a Project Proponent or landowners' choice to discontinue forest carbon project activities. Such mitigation measures can include contributions to the buffer pool, insurance, or other risk mitigation measures approved by ACR.

[3] Ibid.

[4] American Carbon Registry (2018), *American Carbon Registry Standard, Version 5.0.* Winrock International, Little Rock, Arkansas.

If using a buffer contribution to mitigate reversals, the Project Proponent must conduct a risk assessment addressing both general and project-specific risk factors. General risk factors include risks such as financial failure, technical failure, management failure, rising land opportunity costs, regulatory and social instability, and natural disturbances. Project-specific risk factors vary by project type but can include land tenure, technical capability and experience of the project developer, fire potential, risks of insect/disease, flooding and extreme weather events, illegal logging potential, and others. If they are using an alternate ACR-approved risk mitigation product, they will not do this risk assessment.

Project Proponents must conduct their risk assessment using the ACR *Tool for Risk Analysis and Buffer Determination.* The output of either tool is an overall risk category, expressed as a fraction, for the project translating into the buffer deduction that must be applied in the calculation of net ERTs (section G1). This deduction must be applied unless the Project Proponent uses another ACR-approved risk mitigation product.

C. BASELINE

C1. IDENTIFICATION OF BASELINE

The Finite Carbon Corporation IFM methodology[5] (approved by ACR in September 2010), takes a Faustmann approach to baseline determination using NPV maximization with a 6% discount rate on future cash flows. The literature supporting Faustmann's original 1849 work forms the basis for modern optimal rotation/investment decisions and forest economics (summarized in Newman 2002[6]) in addition to appearing in over 300 other book and journal articles. One of the reasons there is such an extensive literature base for NPV maximization is that the Faustmann approach to forest investment and optimal rotation is not perfect. Like the basic economic model of supply and demand, these underlying theorems go far to predict how agents will act, however they do not correctly account for all situations.

In the Finite IFM methodology, the 6% discount is an assumption for how a common industrial forest landowner would make their forest management decisions. This 6% NPV maximization determination of the baseline level of emission and sequestration is appropriate in that it gives a common transparent and conservative metric by which landowners, project developers, verifiers, and offset purchasers can base their assessment of an ACR IFM carbon project. However, less than 40% of aggregate U.S. timber supply comes from Private Industrial (PI) timberland[7] necessitating an adaption of the methodology to allow consideration of other landowner classes who are actively managing their forests.

This methodology is the same as the Finite Carbon methodology in that it quantifies GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline management practice levels. Emission Reduction Tons (ERTs) are quantified for increased sequestration through retention of annual forest growth when project activities exceed the baseline.

The baseline determination is project-specific and must describe the harvesting scenario that would maximize NPV of perpetual wood products harvests over a 100-year modeling period. The discount rate assumptions for calculating NPV[8] vary by ownership class (Table 1) and include the 6% rate for PI timberlands from the Finite methodology. Actual landowner discount rate assumptions are typically not

[5] ACR Approved Methodology (2010), *Methodology for Quantifying GHG Removals and Emission Reductions through Increased Forest Carbon Sequestration on U.S. Timberlands.* Finite Carbon Corporation. https://americancarbonregistry.org/carbon-accounting/standards-methodologies/improved-forest-management-ifm-methodology-for-non-federal-u-s-forestlands/ifm-methodology-for-non-federal-u-s-forestlands_v1-0_semptember-2011_final.pdf

[6] Newman, D.H. 2002. Forestry's golden rule and the development of the optimal forest rotation literature. J. Econ. 8: 5–27

[7] See Tables 7-10 in Adams, D.M.; Haynes, R.W. and A. Daigneault. 2006. Estimated timber harvest by U.S. region and ownership, 1950-2002. PNW-GTR-659. Portland, OR: USDA, Forest Service, Pacific Northwest Research Station. 64 p

[8] Sewall, Sizemore & Sizemore, Mason, Bruce & Girard, Inc and Brookfield internal research.2010.Global Timberlands Research Report. http://www.industryintel.com/Corporate/downloads/4QBrookfield2010.pdf

publicized in the scientific literature and companies, individuals, and organizations by and large do not share the values they use. However, approximate discount rates can be indirectly estimated by using forest economic theory and the age-class structure distribution of different U.S. forest ownership classes.

Amacher et al. (2003)[9] and Beach et al. (2005)[10] provide literature reviews and a basis of economic analysis of non-industrial private forest (NIPF) harvesting decisions. Newman and Wear (1993)[11] show that Industrial and NIPF owners both demonstrate behavior consistent with profit maximization, yet the determinants of profit differ with the NIPF owners deriving significant non-market benefits associated with standing timber. Pattanayak et al. (2002)[12] revisited the problem as they studied NIPF timber supply and found joint optimization of timber and non-timber values while Gan et al. (2001)[13] showed that the impact of a reduced discount rate actually had the same impact as the addition of an amenity value.

The United States Department of Agriculture (USDA) Forest Inventory and Analysis (FIA) group provides inventory data on forests in their periodic assessment of forest resources (Smith et al. 2009[14]). This data allows for the analysis of total U.S. forest acres by age class for three broad ownership classes: Private, State, and National Forest. While the publicly available FIA data does not include any further breakdown of the private ownership group, we were provided with the twenty-year age class data from USDA FIA research foresters, including private corporate and private non-corporate classes. Bringing this economic theoretical framework together with this data aided in the derivation of discount rate value estimates for other forestland ownership classes (Table 1).

This methodology establishes an average baseline determination technique for all major non-federal forest ownership classes in the United States. Project Proponents shall use the baseline discount rate values in Table 1 for the appropriate ownership class to identify a project-specific NPV-maximizing baseline scenario. Project Proponents then design a project scenario for the purposes of increased carbon sequestration. The project scenario by definition will result in a lower NPV than the baseline scenario. The difference between these two harvest forecasts are the basis for determining carbon impacts and ERTs attributable to the project.

[9] Amacher, G.S., Conway, M.C., and J. Sullivan. 2003. Econometric analyses of nonindustrial forest landowners: is there anything left to study? Journal of Forest Economics 9, 137–164

[10] Beach, R.H., Pattanayak, S.K., Yang, J.C., Murray, B.C., and R.C. Abt. 2005. Econometric studies of non-industrial private forest management a review and synthesis. Forest Policy and Economics, 7(3), 261-281

[11] Newman, D.H. and D.N. Wear. 1993. Production economics of private forestry: a comparison of industrial and nonindustrial forest owners. American Journal of Agricultural Economics 75:674-684

[12] Pattanayak, S., Murray, B., Abt, R., 2002. How joint is joint forest production? An econometric analysis of timber supply conditional on endogenous amenity values. Forest Science 47 (3), 479– 491

[13] Gan, J., Kolison Jr., S.H. and J.P. Colletti. 2001. Optimal forest stock and harvest with valuing non-timber benefits: a case of U.S. coniferous forests. Forest Policy and Economics 2(2001), 167-178

[14] Smith, W. Brad, tech. coord.; Miles, Patrick D., data coord.; Perry, Charles H., map coord.; Pugh, Scott A., Data CD coord. 2009. Forest Resources of the United States, 2007. GTR WO-78. Washington, DC: USDA, Forest Service, Washington Office. 336 p

Table 1. Discount rates for Net Present Value determinations by U.S. Forestland Ownership Class.

Ownership	Annual Discount Rate
Private Industrial	6%
Private Non-Industrial	5%
Tribal	5%
Non-governmental organization	4%
Non-federal public lands	4%

The IFM baseline is the legally permissible harvest scenario that would maximize NPV of perpetual wood products harvests. The baseline management scenario shall be based on silvicultural prescriptions recommended by published state or federal agencies to perpetuate existing onsite timber producing species while fully utilizing available growing space. Where the baseline management scenario involves replacement of existing onsite timber producing species (e.g. where forest is converted to plantations, replacing existing onsite timber-producing species), the management regime should similarly be based on silvicultural prescriptions recommended by published state or federal agencies, and must adhere to all applicable laws and regulations. The resulting harvest schedule is used to establish baseline stocking levels through the Crediting Period.

Required inputs for the project NPV calculation include the results of a recent timber inventory of the project lands, prices for wood products of grades that the project would produce, costs of logging, reforestation and related costs, silvicultural treatment costs, and carrying costs. Project Proponents shall include roading and harvesting costs as appropriate to the terrain and unit size. Project Proponents must model growth of forest stands through the Crediting Period. Project Proponents should use a constrained optimization program that calculates the maximum NPV for the harvesting schedule while meeting any forest practice legal requirements. The annual real (without inflation) discount rate for each non-federal owner class is given in Table 1. Wood products must be accounted.

Consideration shall be given to a reasonable range of feasible baseline assumptions and the selected assumptions should be plausible for the duration of the baseline application.

The ISO 14064-2 principle of conservativeness must be applied for the determination of the baseline scenario. In particular, the conservativeness of the baseline is established with reference to the choice of assumptions, parameters, data sources and key factors so that project emission reductions and removals are more likely to be under-estimated rather than over-estimated, and that reliable results are maintained over a range of probable assumptions. However, using the conservativeness principle does not always imply the use of the "most" conservative choice of assumptions or methodologies[15].

C 1.1 Confidentiality of Proprietary Information

While it remains in the interest of the general public for Project Proponents to be as transparent as possible regarding GHG reduction projects, the Project Proponent may choose at their own option to designate any information regarded as confidential due to proprietary considerations. If the Project Proponent chooses to identify information related to financial performance as confidential, the Project Proponent must submit the confidential baseline and project documentation in a separate file marked

[15] ISO 14064-2:2006(E)

"Confidential" to ACR and this information shall not be made available to the public. ACR and the validation/verification body shall utilize this information only to the extent required to register the project and issue ERTs. If the Project Proponent chooses to keep financial information confidential, a publically available GHG Project Plan must still be provided to ACR.

C2. BASELINE STRATIFICATION

If the project activity area is not homogeneous, stratification may be used to improve the modeling of management scenarios and precision of carbon stock estimates. Different stratifications may be used for the baseline and project scenarios. For estimation of baseline carbon stocks, strata may be defined on the basis of parameters that are key variables for estimating changes in managed forest carbon stocks, for example:[16]

a. Management regime
b. Species or cover types
c. Size and density class
d. Site class
e. Age Class

C3. BASELINE NET REDUCTIONS AND REMOVALS

Baseline carbon stock change must be calculated for the entire Crediting Period. The baseline stocking level used for the stock change calculation is derived from the baseline management scenario developed in section C1. This methodology requires 1) annual baseline stocking levels to be determined for the entire Crediting Period, 2) a long-term average baseline stocking level be calculated for the Crediting Period, and 3) the change in baseline carbon stocks be computed for each time period, t.

The following equations are used to construct the baseline stocking levels using models described in section 3.1 and wood products calculations described in section 3.2:

$$\Delta C_{BSL,TREE,t} = \left(C_{BSL,TREE,t} - C_{BSL,TREE,t-1}\right) \quad (1)$$

where:

t	Time in years
$\Delta C_{BSL,TREE,t}$	Change in the baseline carbon stock stored in above and below ground live trees (in metric tons CO_2) for year t.
$C_{BSL,TREE,t}$	Change in the baseline value of carbon stored in above and below ground live trees at the beginning of the year t (in metric tons CO_2) and t-1 signifies the value in the prior year.

[16] Please note this list is not exhaustive and only includes examples of some common stratification parameters.

$$\Delta C_{BSL,DEAD,t} = \left(C_{BSL,DEAD,t} - C_{BSL,DEAD,t-1}\right) \quad (2)$$

where:

t	Time in years
$\Delta C_{BSL,\ DEAD,t}$	Change in the baseline carbon stock stored in dead wood (in metric tons CO_2) for year *t*.
$C_{BSL,\ DEAD,t}$	Change in the baseline value of carbon stored in dead wood at the beginning of the year *t* (in metric tons CO_2) and *t*-1 signifies the value in the prior year.

$$\overline{C}_{BSL,HWP} = \frac{\sum_{t=1}^{20} C_{BSL,HWP,t}}{20} \quad (3)$$

where:

t	Time in years
$\overline{C}_{BSL,HWP}$	Twenty-year average value of annual carbon remaining stored in wood products 100 years after harvest (in metric tons of CO_2)
$C_{BSL,HWP,t}$	Baseline value of carbon remaining in wood products 100 years after being harvested in the year *t* (in metric tons CO_2).

Note: Please see section 3.2 for detailed instructions on baseline wood products calculations.

$$\overline{GHG}_{BSL} = \frac{\sum_{t=1}^{20}\left(BS_{BSL,t} \cdot ER_{CH_4} \cdot \frac{16}{44} \cdot GWP_{CH_4}\right)}{20} \quad (4)$$

where:

t	Time in years
$\overline{GHG}_{BSL}$	Twenty-year average value of greenhouse gas emissions (in metric tons CO_2e) resulting from the implementation of the baseline.
$BS_{BSL,t}$	Carbon stock (in metric tons CO_2) in logging slash burned in the baseline in year *t*.

ER_{CH4}	Methane (CH_4) emission ratio (ratio of CO_2 as CH_4 to CO_2 burned). If local data on combustion efficiency is not available or if combustion efficiency cannot be estimated from fuel information, use IPCC default value[17] of 0.012
16/44	Molar mass ratio of CH_4 to CO_2
GWP_{CH4}	100-year global warming potential (in CO_2 per CH_4) for CH_4 (IPCC SAR-100 value of 21 per the Fourth Assessment Report)[18]

Carbon stock calculation for logging slash burned ($BS_{BSL,t}$) shall use the method described in Section 3.1.1 for bark, tops and branches, and section 3.1.2 if dead wood is selected. The reduction in carbon stocks due to slash burning in the baseline must be properly accounted in equations 1 and 2.

To calculate long-term average baseline stocking level for the Crediting Period use:

$$C_{BSL,AVE} = \frac{\sum_{t=0}^{20}\left(C_{BSL,TREE,t} + C_{BSL,DEAD,t}\right)}{20} + \overline{C}_{BSL,HWP} \quad (5)$$

where:

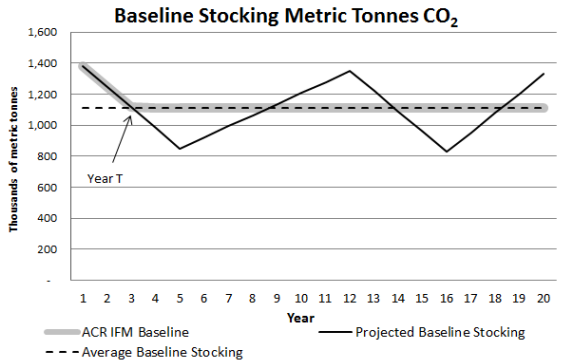
t	Time period (in years)
t^*	A rolling value from 1 to 21 years to reference the accumulated stock in HWP in each year t=1 to t=21
$C_{BSL,AVE}$	20-year average baseline carbon stock (in metric tons CO_2)
$C_{BSL,TREE,t}$	Baseline value of carbon stored in above and below ground live trees (in metric tons CO_2) at the beginning of the year t
$C_{BSL,DEAD,t}$	Baseline value of carbon stored in standing and lying dead trees at the beginning of the year t (in metric tons CO_2)
$\overline{C}_{BSL,HWP}$	Twenty-year average value of annual carbon remaining stored in wood products 100 years after harvest (in metric tons of CO_2)

[17] Table 3A.1.15, Annex 3A.1, GPG-LULUCF (IPCC 2003)

[18] Table 2.14, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://ipccwg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf.

Change in baseline carbon stock is computed for each time period. The Project Proponent shall provide a graph of the projected baseline stocking levels and the long-term average baseline stocking level for the entire Crediting Period (see Figure1). Annual projected stocking levels are used for the baseline stock change calculation until the projected stocking level reaches the long term average (time t = T). Thereafter, the long-term average stocking level is used in the baseline stock change calculation for the entire Project Period.

a) Above average stocking



b) Below average stocking

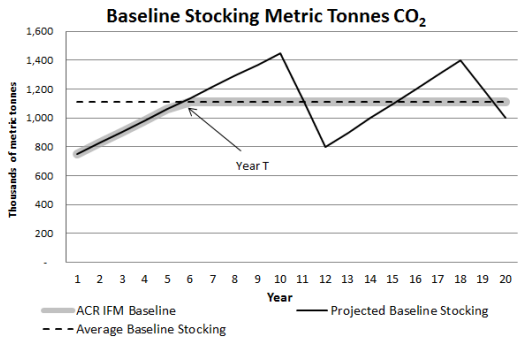


Figure 1. Sample Baseline Stocking Graph for project beginning: a) above 20-year average baseline stocking, and b) below 20-year baseline stocking.

The following equations must be applied until year t equals T:

$$\Delta C_{BSL,t} = \Delta C_{BSL,TREE,t} + \Delta C_{BSL,DEAD,t} + \overline{C}_{BSL,HWP} - \overline{GHG}_{BSL} \quad (6)$$

where:

t	Time in years
$\Delta C_{BSL,t}$	Change in the baseline carbon stock (in metric tons CO_2) for year t.
$\Delta C_{BSL,TREE,t}$	Change in the baseline carbon stock stored in above and below ground live trees (in metric tons CO_2) for year t.
$\Delta C_{BSL,DEAD,t}$	Change in the baseline carbon stock stored in dead wood pools live trees (in metric tons CO_2) for year t.
$\overline{C}_{BSL,HWP}$	Twenty-year average value of annual carbon remaining in wood products 100 years after harvest (in metric tons CO_2).
$\overline{GHG}_{BSL}$	Twenty-year average value of annual greenhouse gas emissions (in metric tons CO_2) resulting from the implementation of the baseline.

Prior to year T (T = year projected stocking reaches the long-term baseline average) the value of $\Delta C_{BSL,t}$ will most likely be negative for projects with initial stocking levels higher than $C_{BSL,AVE}$ or positive for

projects with initial stocking levels lower than $C_{BSL,AVE}$. If years elapsed since the start of the IFM project activity (t) is ≥T to compute long-term average stock change use:

$$\Delta C_{BSL,t} = 0 \quad (7)$$

3.1 Stocking Level Projections in the Baseline

$C_{BSL,TREE,t}$ and $C_{BSL,DEAD,t}$ must be estimated using models of forest management across the baseline period. Modeling must be completed with a peer reviewed forestry model that has been calibrated for use in the project region. The GHG Plan must detail what model is being used and what variants have been selected. All model inputs and outputs must be available for inspection by the verifier. The baseline must be modeled over a 20-year period.

Examples of appropriate models include:

- FVS: Forest Vegetation Simulator
- SPS: Stand Projection System
- FIBER: USDA, Forest Service
- FPS: Forest Projection System by Forest Biometrics
- CRYPTOS and CACTOS: California Conifer Timber Output Simulator

Models must be:

- Peer reviewed in a process involving experts in modeling and biology/forestry/ecology
- Used only in scenarios relevant to the scope for which the model was developed and evaluated
- Parameterized for the specific conditions of the project

The output of the models must include either projected total aboveground and below ground carbon per acre, volume in live aboveground tree biomass, or another appropriate unit by strata in the baseline. Where model projections are output in five or ten year increments, the numbers shall be annualized to give a stock change number for each year.

If the output for the tree is the volume, then this must be converted to biomass and carbon using equations in Section 3.1.1. If processing of alternative data on dead wood is necessary, equations in section 3.1.2 may be used. Where models do not predict dead wood dynamics, the baseline harvesting scenario may not decrease dead wood more than 50% through the Crediting Period.

3.1.1 Tree Carbon Stock Calculation

The mean carbon stock in aboveground biomass per unit area is estimated based on field measurements in sample plots. A sampling plan must be developed that describes the inventory process including sample size, determination of plot numbers, plot layout and locations, and data collected. Plot data used for biomass calculations may not be older than 10 years. Plots may be permanent or temporary and they may have a defined boundary or use variable radius sampling methods. Biomass for each tree is calculated from its merchantable volume using a component ratio method. The Project Proponent must use the same set of equations, diameter at breast height thresholds, and selected biomass components for *ex ante* and *ex post* baseline and project estimates.

To ensure accuracy and conservative estimation of the mean aboveground live biomass per unit area within the Project Area, Projects must account for missing cull in both the *ex ante* and *ex post* baseline and project scenarios. Determine missing cull deductions with cull attribute data collected during field measurement of sample plots.

The following steps are used to calculate tree biomass:

Step 1: Determine the biomass of the merchantable component of each tree based on appropriate volume equations published by USDA Forest Service (if locally derived equations are not available use regional or national equations as appropriate) and green volume inside bark, oven-dry tree specific gravity for each species.

Step 2: Determine aboveground biomass by choosing a combination of the following components: stump, bark, tops and branches, and/or foliage, in addition to below-ground biomass, by applying component ratios from Jenkins *et al* (2003) Table 6[19], where biomass of each component is calculated as its component ratio * merchantable stem biomass from Step 1 * (1 / stem wood component ratio). If stump, top, and branch components are included, please use the quantification methodology found in Woodall et al. 2011[20]. Note that the same components must be calculated for *ex ante* and *ex post* baseline and project estimates.

Step 3: Using the sum of the selected biomass components for individual trees, determine the per plot estimate of total tree biomass for each plot.

Step 4: Determine the tree biomass estimate for each stratum by calculating a mean biomass per acre estimate from plot level biomass derived in step 3 multiplied by the number acres in the stratum.

Step 5: Determine total project carbon (in metric tons CO_2) by summing the biomass of each stratum for the project area and converting biomass to carbon by multiplying by 0.5, kilograms to metric tons by dividing by 1000, and finally carbon to CO_2 by multiplying by 3.664.

Note: The FVS Fire and Fuels Extension volume-based default estimates[21] of Live Carbon are compliant with the above, but do not include bark and stump components.

3.1.2 Dead Wood Calculation

Dead wood included in the methodology comprises two components only – standing dead wood and lying dead wood. Below-ground dead wood is conservatively neglected. Considering the differences in the two components, different sampling and estimation procedures shall be used to calculate the changes in dead wood biomass of the two components.

[19] Jenkins, J.; Chojnacky, D.C.; Heath, L.S.; Birdsey, R.A. 2003. National Scale Biomass Estimators for United States Tree Species. Forest Science. 49(1): 12-35

[20] Woodall, Christopher W.; Heath, Linda S.; Domke, Grant M.; Nichols, Michael C. 2011. Methods and equations for estimating aboveground volume, biomass, and carbon for trees in the U.S. forest inventory, 2010. Gen. Tech. Rep. NRS-88. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northern Research Station.

[21] Hoover, C.M. and Rebain, S.A., 2011. Forest carbon estimation using the Forest Vegetation Simulator: Seven things you need to know. http://www.nrs.fs.fed.us/pubs/gtr/gtr_nrs77.pdf

3.1.2.1 Standing Dead Wood (if included)

Step 1: Standing dead trees shall be measured using the same criteria and monitoring frequency used for measuring live trees. The decomposed portion that corresponds to the original above-ground biomass is discounted.

Step 2: The decomposition class of the dead tree and the diameter at breast height shall be recorded and the standing dead wood is categorized under the following four decomposition classes:

1. Tree with branches and twigs that resembles a live tree (except for leaves)
2. Tree with no twigs but with persistent small and large branches
3. Tree with large branches only
4. Bole only, no branches

Step 3: Biomass must be estimated using the component ratio method used for live trees for decomposition classes 1, 2, and 3 with deductions as stated in Step 4 (below). When the standing dead tree is in decomposition class 4, the biomass estimate must be limited to the main stem of the tree. If the top of the standing dead tree is missing, then top and branch biomass may be assumed to be zero. Identifiable tops on the ground meeting category 1 criteria may be directly measured. For trees broken below minimum merchantability specifications used in the tree biomass equation, existing standing dead tree height shall be used to determine tree bole biomass.

Step 4: The biomass of dead wood is determined by using the following dead wood density classes deductions: Class 1 – 97% of live tree biomass; Class 2 – 95% of live tree biomass; Class 3 – 90% of live tree biomass; Class 4 – 80% of live tree biomass[22].

Step 5: Determine total project standing dead carbon (in metric tons CO_2) by summing the biomass of each stratum for the project area and converting biomass to carbon by multiplying by 0.5, kilograms to metric tons by dividing by 1000, and finally carbon to CO_2 by multiplying by 3.664.

Note: The FVS Fire and Fuels Extension estimates of Standing Dead Carbon are compliant with this methodology, but do not include bark and stump components.

3.1.2.2 Lying Dead Wood (if selected)

The lying dead wood pool is highly variable, and stocks may or may not increase as the stands age depending if the forest was previously unmanaged (mature or unlogged) where it would likely increase or logged with logging slash left behind where it may decrease through time.

[22] IPCC Good Practice Guidelines 2006. http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf_files/Chp4/Chp4_3_Projects.pdf

Step 1: Lying dead wood must be sampled using the line intersect method (Harmon and Sexton 1996).[23,24] At least two 50-meter lines (164 ft) are established bisecting each plot and the diameters of the lying dead wood (≥ 10 cm diameter [≥ 3.9 inches]) intersecting the lines are measured.

Step 2: The dead wood is assigned to one of the three density states (sound, intermediate and rotten) by species using the 'machete test', as recommended by IPCC Good Practice Guidance for LULUCF (2003), Section 4.3.3.5.3. The following dead wood density class deductions must be applied to the three decay classes: For Hardwoods, sound – no deduction, intermediate - 0.45, rotten - 0.42; for Softwoods, sound – no deduction, intermediate - 0.71, rotten - 0.45.[25]

Step 3: The volume of lying dead wood per unit area is calculated using the equation (Warren and Olsen 1964)[26] as modified by Van Wagner (1968)[27] separately for each density class

$$V_{LDW,DC} = \pi^2 \left(\sum_{n=1}^{N} D_{n,DC}^2 \right) \Big/ (8 \cdot L) \quad (8)$$

where:

$V_{LDW,\,DC}$	Volume (in cubic meters per hectare) of lying dead wood in density class *DC* per unit area;
$D_{n,DC}$	Diameter (in centimeters) of piece number *n*, of *N* total pieces in density class DC along the transect;
L	Length (in meters) of transect

Step 4: Volume of lying dead wood shall be converted into biomass using the following relationship:

$$B_{LDW} = A \sum_{DC=1}^{3} V_{LDW,DC} \cdot WD_{DC} \quad (9)$$

where:

B_{LDW}	Biomass (in kilograms per hectare) of lying dead wood per unit area;
A	Area (in hectares);

[23] Harmon, M.E. and J. Sexton. (1996) Guidelines for measurements of wood detritus in forest ecosystems. U.S. LTER Publication No. 20. U.S. LTER Network Office, University of Washington, Seattle, WA, USA.
[24] A variant on the line intersect method is described by Waddell, K.L. 2002. Sampling coarse wood debris for multiple attributes in extensive resource inventories. Ecological Indicators 1: 139-153. This method may be used in place of Steps 1 to 3
[25] USFS FIA Phase 3 proportions
[26] Warren, W.G. and Olsen, P.F. (1964) A line intersect technique for assessing logging waste. *Forest Science* 10:267-276
[27] Van Wagner, C.E. (1968). The line intersect method in forest fuel sampling. *Forest Science* 14: 20-26

$V_{LDW,DC}$ Volume (in cubic meters per hectare) of lying dead wood in density class DC per unit area

WD_{DC} Basic wood density (in kilograms per cubic meter) of dead wood in the density class—sound (1), intermediate (2), and rotten (3)

Step 5: Determine total project lying dead carbon by summing the biomass of each stratum for the project area and converting biomass to dry metric tons of Carbon by multiplying by 0.5, kilograms to metric tons by dividing by 1000, and finally carbon to CO_2 by multiplying by 3.664.

3.2 Wood Products Calculations

There are five steps required to account for the harvesting of trees and to determine carbon stored in wood products in the baseline and project scenarios[28]:

1. Determining the amount of carbon in trees harvested that is delivered to mills (bole without bark).
2. Accounting for mill efficiencies.
3. Estimating the carbon remaining in in-use wood products 100 years after harvest.
4. Estimating the carbon remaining in landfills 100 years after harvest.
5. Summing the carbon remaining in wood products 100 years after harvest.

Step 1: Determine the Amount of Carbon in Harvested Wood Delivered to Mills

The following steps must be followed to determine the amount of carbon in harvested wood if the biomass model does not provide metric tons carbon in the bole, without bark. If it does, skip to step 2

1. Determine the amount of wood harvested (actual or baseline) that will be delivered to mills, by volume (cubic feet) or by green weight (lbs.), and by species for the current year (y). In all cases, harvested wood volumes and/or weights must exclude bark.
    a. Baseline harvested wood quantities and species are derived from modeling a baseline harvesting scenario using an approved growth model.
    b. Actual harvested wood volumes and species must be based on verified third party scaling reports, where available. Where not available, documentation must be provided to support the quantity of wood volume harvested.
        i. If actual or baseline harvested wood volumes are reported in units besides cubic feet or green weight, convert to cubic feet using the following conversion factors:

Volume multipliers for converting timber and chip units to Cubic Feet	
Unit	**Factor**

[28] Adapted from Appendix C of the California Air Resources Board Compliance Offset Protocol - U.S. Forest Projects, November 14, 2014.

Bone Dry Tons	71.3
Bone Dry Units	82.5
Cords	75
Cubic Meters	35.3
Cunits-Chips (CCF)	100
Cunits-Roundwood	100
Cunits-Whole tree chip	126
Green tons	31.5
MBF-Doyle	222
MBF-International 1/4"	146
MBF-Scribner ("C" or "Small")	165
MBF-Scribner ("Large" or "Long")	145
MCF-Thousand Cubic Feet	1000
Oven Dried Tonnes	75.8

2. If a volume measurement is used, multiply the cubic foot volume by the appropriate green specific gravity by species from table 5-3a of the USFS Wood Handbook[29]. This results in pounds of biomass with zero moisture content. If a particular species is not listed in the Wood Handbook, it shall be at the verifier's discretion to approve a substitute species. Any substitute species must be consistently applied across the baseline and with-project calculations.

3. If a weight measurement is used, subtract the water weight based on the moisture content of the wood. This results in pounds of biomass with zero moisture content.

4. Multiply the dry weight values by 0.5 pounds of carbon/pound of wood to compute the total carbon weight.

5. Divide the carbon weight by 2,204.6 pounds/metric ton and multiply by 3.664 to convert to metric tons of CO_2. Sum the CO2 for each species into saw log and pulp volumes (if applicable), and then again into softwood species and hardwood species. These values are used in the next step, accounting for mill efficiencies. Please note that the categorization criteria (upper and lower DBH limits) for hardwood/softwood saw log and pulp volumes are to remain the same between the baseline and project scenario.

Step 2: Account for Mill Efficiencies

Multiply the total carbon weight (metric tons of carbon) for each group derived in Step 1 by the mill efficiency identified for the project's mill location(s) in the Regional Mill Efficiency Database, found on the Reference documents section of this methodology's website. This is the total carbon transferred into

[29] Forest Products Laboratory. Wood handbook - Wood as an engineering material. General Technical Report FPL-GTR-190. Madison, WI: U.S. Department of Agriculture, Forest Service, Forest Products Laboratory: 508 p. 2010.

wood products. The remainder (sawdust and other byproducts) of the harvested carbon is considered to be immediately emitted to the atmosphere for accounting purposes in this methodology.

Step 3: Estimate the Carbon Storage 100 Years after Harvest in In-Use Wood Products

The amount of carbon that will remain stored in in-use wood products for 100 years depends on the rate at which wood products either decay or are sent to landfills. Decay rates depend on the type of wood product that is produced. Thus, in order to account for the decomposition of harvested wood over time, a decay rate is applied to methodology wood products according to their product class. To approximate the climate benefits of carbon storage, this methodology accounts for the amount of carbon stored 100 years after harvest. Thus, decay rates for each wood product class have been converted into "storage factors" in the table below.

100-year storage factors[30]		
Wood Product Class	**In-Use**	**Landfills**
Softwood Lumber	0.234	0.405
Hardwood Lumber	0.064	0.490
Softwood Plywood	0.245	0.400
Oriented Strandboard	0.349	0.347
Non Structural Panels	0.138	0.454
Miscellaneous Products	0.003	0.518
Paper	0	0.151

Steps to Estimate Carbon Storage in In-Use Products 100 Years after Harvest

To determine the carbon storage in in-use wood products after 100 years, the first step is to determine what percentage of a Project Area's harvest will end up in each wood product class for each species (where applicable), separated into hardwoods and softwoods. This must be done by either:

- Obtaining a verified report from the mill(s) where the Project Area's logs are sold indicating the product categories the mill(s) sold for the year in question; or
- If a verified report cannot be obtained, looking up default wood product classes for the project's Assessment Area, as given in the most current Assessment Area Data File found on the Reference Documents section of this methodology's website.

If breakdowns for wood product classes are not available from either of these sources, classify all wood products as "miscellaneous."

[30] Smith JE, Heath LS, Skog KE, Birdsey RA (2006) Methods for calculating forest ecosystem and harvested carbon with standard estimates for forest types of the United States. In: General Technical Report NE-343 (eds Usdafs), PP. 218. USDA Forest service, Washington, DC, USA.

Once the breakdown of in-use wood product categories is determined, use the 100-year storage factors to estimate the amount of carbon stored in in-use wood products 100 years after harvest:

1. Assign a percentage to each product class for hardwoods and softwoods according to mill data or default values for the project.
2. Multiply the total carbon transferred into wood products by the % in each product class
3. Multiply the values for each product class by the storage factor for in-use wood products
4. Sum all of the resulting values to calculate the carbon stored in in-use wood products after 100 years (in units of CO2-equivalent metric tons).

Step 4: Estimate the Carbon Storage 100 Years after Harvest for Wood Products in Landfills

To determine the appropriate value for landfill carbon storage, perform the following steps:

1. Assign a percentage to each product class for hardwoods and softwoods according to mill data or default values for the project.
2. Multiply the total carbon transferred into wood products by the % in each product class.
3. Multiply the values for each product class by the storage factor for landfill carbon.
4. Sum all of the resulting values to calculate the carbon stored in landfills after 100 years (in units of CO2-equivalent metric tons).

Step 5: Determine Total Carbon Storage in Wood Products 100 Years after Harvest

The total carbon storage in wood products after 100 years for a given harvest volume is the sum of the carbon stored in landfills after 100 years and the carbon stored in in-use wood products after 100 years. This value is used for input into the ERT calculation worksheet. The value for the actual harvested wood products will vary every year depending on the total amount of harvesting that has taken place. The baseline value is the 100-year average value, and does not change from year to year.

C4. MONITORING REQUIREMENTS FOR BASELINE RENEWAL

A project's Crediting Period is the finite length of time for which the baseline scenario is valid and during which a project can generate offsets against its baseline.

A Project Proponent may apply to renew the Crediting Period by[31]:

- Re-submitting the GHG Project Plan in compliance with then-current ACR standards and criteria
- Re-evaluating the project baseline
- Demonstrating additionality against then-current regulations, common practice and implementation barriers

[31] American Carbon Registry (2018), *American Carbon Registry Standard, Version 5.0.* Winrock International, Little Rock, Arkansas.

- Using ACR-approved baseline methods, emission factors, and tools in effect at the time of Crediting Period renewal, and
- Undergoing validation and verification by an approved validation/verifier body

C5. ESTIMATION OF BASELINE UNCERTAINTY

It is assumed that the uncertainties associated with the estimates of the various input data are available, either as default values given in IPCC Guidelines (2006), IPCC GPG-LULUCF (2003), or estimates based on sound statistical sampling. Uncertainties arising from the measurement and monitoring of carbon pools and the changes in carbon pools shall always be quantified.

Indisputably conservative estimates can also be used instead of uncertainties, provided that they are based on verifiable literature sources. In this case the uncertainty is assumed to be zero. However, this section provides a procedure to combine uncertainty information and conservative estimates resulting in an overall project scenario uncertainty.

It is important that the process of project planning consider uncertainty. Procedures including stratification and the allocation of sufficient measurement plots can help ensure low uncertainty. It is good practice to consider uncertainty at an early stage to identify the data sources with the highest risk to allow the opportunity to conduct further work to diminish uncertainty. Estimation of uncertainty for pools and emissions sources for each measurement pool requires calculation of both the mean and the 90% confidence interval. In all cases uncertainty should be expressed as the 90% confidence interval as a percentage of the mean.

The uncertainty in the baseline scenario should be defined as the square root of the summed errors in each of the measurement pools. For modeled results use the confidence interval of the input inventory data. For wood products and logging slash burning emissions use the confidence interval of the inventory data. The errors in each pool shall be weighted by the size of the pool so that projects may reasonably target a lower precision level in pools that only form a small proportion of the total stock.

Therefore,

$$UNC_{BSL} = \frac{\sqrt{\left(C_{BSL,TREE,1} \cdot e_{BSL,TREE}\right)^2 + \left(C_{BSL,DEAD,1} \cdot e_{BSL,DEAD}\right)^2 + \left(\overline{C}_{BSL,HWP} \cdot e_{BSL,TREE}\right)^2 + \left(\overline{GHG}_{BSL} \cdot e_{BSL,TREE}\right)^2}}{C_{BSL,TREE,1} + C_{BSL,DEAD,1} + C_{BSL,HWP} + \overline{GHG}_{BSL}} \quad (10)$$

where:

UNC_{BSL}	Percentage uncertainty in the combined carbon stocks in the baseline.
$C_{BSL,TREE,1}$	Carbon stock in the baseline stored in above and below ground live trees (in metric tons CO_2) for the initial inventory in year *1*.
$C_{BSL,DEAD,1}$	Carbon stock in the baseline stored in dead wood (in metric tons CO_2) for the initial inventory in year *1*.

$\overline{C}_{BSL,HWP}$	Twenty-year baseline average value of annual carbon (in metric tons CO_2) remaining stored in wood products 100 years after harvest.
$\overline{GHG}_{BSL}$	Twenty-year average value of annual greenhouse gas emissions (in metric tons CO_2e) resulting from the implementation of the baseline.
$e_{BSL,TREE}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in above and below ground live trees (in metric tons CO_2) for the initial inventory in year *1*.
$e_{BSL,DEAD}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in dead wood (in metric tons CO_2) for the initial inventory in year *1*.

D. WITH-PROJECT SCENARIO

D1. WITH-PROJECT STRATIFICATION

If the project activity area is not homogeneous, stratification may be carried out to improve the precision of carbon stock estimates. Different stratifications may be used for the baseline and project scenarios. For estimation of with-project scenario carbon stocks, strata may be defined on the basis of parameters that are key variables determining forest carbon stocks, for example:

a. Management regime
b. Species or cover types
c. Size and density class
d. Site class
e. Age class

Project Proponents must present in the GHG Plan an *ex ante* stratification of the project area or justify the lack of it. The number and boundaries of the strata defined *ex ante* may change during the Crediting Period (*ex post*).

The *ex post* stratification shall be updated due to the following reasons:

- Unexpected disturbances occurring during the Crediting Period (e.g. due to fire, pests or disease outbreaks), affecting differently various parts of an originally homogeneous stratum
- Forest management activities (e.g. cleaning, planting, thinning, harvesting, coppicing, replanting) may be implemented in a way that affects the existing stratification
- Established strata may be merged if reason for their establishment has disappeared

D2. MONITORING PROJECT IMPLEMENTATION

Information shall be provided, and recorded in the GHG Plan, to establish that:

- The geographic position of the project boundary is recorded for all areas of land
- The geographic coordinates of the project boundary (and any stratification inside the boundary) are established, recorded and archived. This can be achieved by field mapping (e.g. using GPS), or by using georeferenced spatial data (e.g. maps, GIS datasets, orthorectified aerial photography or georeferenced remote sensing images)
- Professionally accepted principles of forest inventory and management are implemented
- Standard operating procedures (SOPs) and quality control / quality assurance (QA/QC) procedures for forest inventory including field data collection and data management shall be applied. Use or adaptation of SOPs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended
- Where commercial timber harvesting occurs in the project area in the with-project scenario, the forest management plan, together with a record of the plan as actually implemented during the project shall be available for validation and verification, as appropriate

D3. MONITORING OF CARBON STOCKS IN SELECTED POOLS

Information shall be provided, and recorded in the GHG Plan, to establish that professionally accepted principles of forest inventory and management are implemented. Standard operating procedures (SOPs) and quality control / quality assurance (QA/QC) procedures for forest inventory including field data collection and data management shall be applied. Use or adaptation of SOPs already applied in national forest monitoring, or available from published handbooks, or from the *IPCC GPG LULUCF 2003*, is recommended. The forest management plan, together with a record of the plan as actually implemented during the project shall be available for validation and verification, as appropriate.

The 90% statistical confidence interval (CI) of sampling can be no more than ±10% of the mean estimated amount of the combined carbon stock at the project area level[32]. If the Project Proponent cannot meet the targeted ±10% of the mean at 90% confidence, then the reportable amount shall be the lower bound of the 90% confidence interval.

At a minimum the following data parameters must be monitored:

- Project area
- Sample plot area
- Tree species
- Tree Biomass
- Wood products volume
- Dead wood pool, if selected

D4. MONITORING OF EMISSION SOURCES

Emissions from biomass burning must be monitored during project activities. When applying all relevant equations provided in this methodology for the *ex ante* calculation of net anthropogenic GHG removals by sinks, Project Proponents shall provide transparent estimations for the parameters that are monitored during the Crediting Period. These estimates shall be based on measured or existing published data where possible. In addition, Project Proponents must apply the principle of

[32] For calculating pooled CI of carbon pools across strata, see equations in Barry D. Shiver, *Sampling Techniques for Forest Resource Inventory (John Wiley & Sons, Inc, 1996)*

conservativeness. If different values for a parameter are equally plausible, a value that does not lead to over-estimation of net anthropogenic GHG removals by sinks must be selected.

D5. ESTIMATION OF PROJECT EMISSION REDUCTIONS OR ENHANCED REMOVALS

This section describes the steps required to calculate $\Delta C_{P,t}$ (net annual carbon stock change under the project scenario; tons CO_2e). This methodology requires: 1) carbon stock levels to be determined in each time period, t, for which a valid verification report is submitted, and 2) the change in project carbon stock be computed from the prior verification time period, t-1.

The following equations are used to construct the project stocking levels using models described in section 3.1 and wood products calculations described in section 3.2:

$$\Delta C_{P,TREE,t} = \left(C_{P,TREE,t} - C_{P,TREE,t-1}\right) \quad (11)$$

where:

t	Time in years
$\Delta C_{P,TREE,t}$	Change in the project carbon stock stored in above and below ground live trees (in metric tons CO_2) for year t.
$C_{P,TREE,t}$	Change in the project value of carbon stored in above and below ground live trees at the beginning of the year t (in metric tons CO_2) and t-1 signifies the value in the prior year.

$$\Delta C_{P,DEAD,t} = \left(C_{P,DEAD,t} - C_{P,DEAD,t-1}\right) \quad (12)$$

where:

t	Time in years
$\Delta C_{P,DEAD,,t}$	Change in the project carbon stock (in metric tons CO_2) for year t.
$C_{P,DEAD,t}$	Change in the project value of carbon stored in dead wood at the beginning of the year t (in metric tons CO_2) and t-1 signifies the value in the prior year.

$$GHG_{P,t} = BS_{P,t} \cdot ER_{CH_4} \cdot \frac{16}{44} \cdot GWP_{CH_4} \quad (13)$$

where:

t	Time in years
$GHG_{P,t}$	Greenhouse gas emission (in metric tons CO2e) resulting from the implementation of the project in year (t).

$BS_{P,t}$	Carbon stock (in metric tons CO_2) in logging slash burned in the project in year *t*.
ER_{CH4}	Methane (CH_4) emission ratio (ratio of CO_2 as CH_4 to CO_2 burned). If local data on combustion efficiency is not available or if combustion efficiency cannot be estimated from fuel information, use IPCC default value of 0.012[33]
16/44	Molar mass ratio of CH_4 to CO_2
GWP_{CH4}	100-year global warming potential (in CO_2e per CH_4) for CH_4 (IPCC SAR-100 value of 21 per the Fourth Assessment Report)[34]

Carbon stock calculation for logging slash burned shall use the method described in Section 3.1.1 for bark, tops and branches, and Section 3.1.2 if dead wood is selected. The reduction in carbon stocks due to slash burning due to project activities must be properly accounted in equations 11 and 12.

To compute change in project carbon stock for each time period use:

$$\Delta C_{P,t} = \Delta C_{P,TREE,t} + \Delta C_{P,DEAD,t} + C_{P,HWP,t} - GHG_{P,t} \quad (14)$$

where:

t	Time in years
$\Delta C_{P,t}$	Change in the project carbon stock (in metric tons CO_2) for year *t*.
$\Delta C_{P,TREE,t}$	Change in the project carbon stock stored in above and below ground live trees (in metric tons CO_2) for year *t*.
$\Delta C_{P,DEAD,t}$	Change in the project carbon stock stored in dead wood pools live trees (in metric tons CO_2) for year *t*.
$C_{P,HWP,t}$	Carbon remaining stored in wood products 100 years after harvest (in metric tons CO_2) for the project in year t.
$GHG_{P,t}$	Greenhouse gas emission (in metric tons CO2e) resulting from the implementation of the project in year (t).

5.1 Tree Biomass, Dead Wood Carbon Calculation, Wood Products

The Project Proponent must use the same set of equations used in Section C3.1.1, C3.1.2, and C3.2 to calculate carbon stocks in the project scenario.

[33] Table 3A.1.15, Annex 3A.1, GPG-LULUCF (IPCC 2003)

[34] Table 2.14, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA

D6. MONITORING OF ACTIVITY-SHIFTING LEAKAGE

There may be no leakage beyond *de minimis* levels through activity shifting to other lands owned, or under management control, by the timber rights owner.

If the project decreases wood product production by >5% relative to the baseline then the Project Proponent and all associated land owners must demonstrate that there is no leakage within their operations – i.e., on other lands they manage/operate outside the bounds of the ACR carbon project.

Such a demonstration must include one of the following:

- Historical records covering all Project Proponent ownership trends in harvest volumes paired with records from the with-project time period showing no deviation from historical trends over most recent 10-year average; *or*

- Forest management plans prepared ≥24 months prior to the start of the project showing harvest plans on all owned/managed lands paired with records from the with-project time period showing no deviation from management plans; *or*

- Entity-wide management certification that requires sustainable practices (programs can include FSC, SFI, or ATFS). Management certification must cover *all* entity owned lands with active timber management programs.

D7. ESTIMATION OF EMISSIONS DUE TO MARKET LEAKAGE

Reductions in product outputs due to project activity may be compensated by other entities in the marketplace. Those emissions must be included in the quantification of project benefits. Market Leakage shall be quantified by either of the following:

1. Applying the appropriate default market leakage discount factor (15, 16, or 17):

    - If the project is able to demonstrate that any decrease in total wood products produced by the project relative to the baseline is less than 5% over the Crediting Period then:

      $$LK = 0 \quad (15)$$

    - Where project activities decrease total wood products produced by the project relative to the baseline by more than 5% but less than 25% over the Crediting Period, the market leakage deduction is 10% (according to VCS AFOLU Guidance Document[35]).

      $$LK = 0.1 \quad (16)$$

    - Where project activities decrease total wood products produced by the project relative to the baseline by 25% or more over the Crediting Period, the market leakage deduction is 40%[36].

[35] http://www.v-c-s.org/sites/v-c-s.org/files/Guidance for AFOLU Projects.pdf

[36] We assume that any decrease in production would be transferred to forests of a similar type.

$$LK = 0.4 \quad (17)$$

2. Directly accounting for market leakage associated with the project activity:

Where directly accounting for leakage, market leakage shall be accounted for at the regional-scale applied to the same general forest type as the project (ie, forests containing the same or substitutable commercial species as the forest in the project area) and shall be based on verifiable methods for quantifying leakage. It is at the verifier's discretion to determine whether the method for quantifying market leakage is appropriate for the project.

D8. ESTIMATION OF WITH-PROJECT UNCERTAINTY

It is assumed that the uncertainties associated with the estimates of the various input data are available, either as default values given in IPCC Guidelines (2006), IPCC GPG-LULUCF (2003), or estimates based on sound statistical sampling. Uncertainties arising from the measurement and monitoring of carbon pools and the changes in carbon pools shall always be quantified.

Indisputably conservative estimates can also be used instead of uncertainties, provided that they are based on verifiable literature sources. In this case the uncertainty is assumed to be zero. However, this section provides a procedure to combine uncertainty information and conservative estimates resulting in an overall project scenario uncertainty.

As with baseline uncertainty, it is important that the process of project planning consider uncertainty. Procedures including stratification and the allocation of sufficient measurement plots can help ensure low uncertainty. It is good practice to consider uncertainty at an early stage to identify the data sources with the highest risk to allow the opportunity to conduct further work to diminish uncertainty. Estimation of uncertainty for pools and emissions sources for each measurement pool requires calculation of both the mean and the 90% confidence interval. In all cases uncertainty should be expressed as the 90% confidence interval as a percentage of the mean.

The uncertainty in the project scenario should be defined as the square root of the summed errors in each of the measurement pools. For modeled results use the confidence interval of the input inventory data. For wood products with measured and documented harvest volume removals use zero as the confidence interval. For estimated wood product removal use the confidence interval of the inventory data. The errors in each pool can be weighted by the size of the pool so that projects may reasonably target a lower precision level in pools that only form a small proportion of the total stock.

Therefore,

$$UNC_{P,t} = \frac{\sqrt{\left(C_{P,TREE,t} \cdot e_{P,TREE}\right)^2 + \left(C_{P,DEAD,t} \cdot e_{P,DEAD}\right)^2 + \left(C_{P,HWP,t} \cdot e_{P,TREE}\right)^2 + \left(GHG_{P,t} \cdot e_{P,TREE}\right)^2}}{C_{P,TREE,t} + C_{P,DEAD,t} + C_{P,HWP,t} + GHG_{P,t}} \quad (18)$$

where:

$UNC_{P,t}$	Percentage uncertainty in the combined carbon stocks in the project in year *t*.

$C_{P,TREE,t}$	Carbon stock in the project stored in above and below ground live trees (in metric tons CO_2) in year *t*.
$C_{P,DEAD,t}$	Carbon stock in the baseline stored in dead wood (in metric tons CO_2) in year *t*.
$C_{P,HWP,t}$	Annual carbon (in metric tons CO_2) remaining stored in wood products in the project 100 years after harvest in year *t*.
$GHG_{P,t}$	Greenhouse gas emission (in metric tons CO_2e) resulting from the implementation of the project in year t.
$e_{P,TREE}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in above and below ground live trees (in metric tons CO_2) for the last remeasurement of the inventory prior to year *t*.
$e_{P,DEAD}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in dead wood (in metric tons CO_2) for the last remeasurement of the inventory prior to year *t*.

E. EX-ANTE ESTIMATION

E1. EX-ANTE ESTIMATION METHODS

The Project Proponent must make an *ex ante* calculation of all net anthropogenic GHG removals and emissions for all included sinks and sources for the entire Crediting Period. Project Proponents shall provide estimates of the values of those parameters that are not available before the start of monitoring activities. Project Proponents must retain a conservative approach in making these estimates.

Uncertainties arising from, for example, biomass expansion factors or wood density, could result in unreliable estimates of both baseline net GHG removals by sinks and the actual net GHG removals by sinks especially when global default values are used. Project Proponents shall identify key parameters that would significantly influence the accuracy of estimates. Local values that are specific to the project circumstances must then be obtained for these key parameters, whenever possible. These values must be based on:

- Data from well-referenced peer-reviewed literature or other well-established published sources; *or*
- National inventory data or default data from IPCC literature that has, whenever possible and necessary, been checked for consistency against available local data specific to the project circumstances; *or*
- In the absence of the above sources of information, expert opinion may be used to assist with data selection. Experts will often provide a range of data, as well as a most probable value for the data. The rationale for selecting a particular data value must be briefly noted in the GHG

plan. For any data provided by experts, the GHG Plan shall also record the expert's name, affiliation, and principal qualification as an expert– plus inclusion of a 1-page summary CV for each expert consulted, included in an annex.

When choosing key parameters based on information that is not specific to the project circumstances, such as in use of default data, Project Proponents must select values that will lead to an accurate estimation of net GHG removals by sinks, taking into account uncertainties. If uncertainty is significant, Project Proponents must choose data such that it tends to under-estimate, rather than over-estimate, net GHG removals by sinks[37].

[37] CDM Approved Consolidated Methodology AR-ACM0001, "Afforestation and Reforestation of Degraded Land"

F. QA/QC AND UNCERTAINTY

F1. METHODS FOR QUALITY ASSURANCE

Standard operating procedures (SOPs) and quality control / quality assurance (QA/QC) procedures for forest inventory including field data collection and data management shall be documented. Use or adaptation of SOPs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended.

F2. METHODS FOR QUALITY CONTROL

Project Proponents shall consider all relevant information that may affect the accounting and quantification of GHG reductions/removals, including estimating and accounting for any decreases in carbon pools and/or increases in GHG emission sources. This methodology sets a *de minimis* threshold of 3% of the final calculation of emission reductions. For the purpose of completeness any decreases in carbon pools and/or increases in GHG emission sources must be included if they exceed the *de minimis* threshold. Any exclusion using the *de minimis* principle shall be justified using fully documented *ex ante* calculations.

F3. CALCULATION OF TOTAL PROJECT UNCERTAINTY

The following equation must be applied:

$$UNC_t = \frac{\sqrt{\left(\Delta C_{BSL,t} \cdot UNC_{BSL}\right)^2 + \left(\Delta C_{P,t} \cdot UNC_{P,t}\right)^2}}{\Delta C_{BSL,t} + \Delta C_{P,t}} \quad (19)$$

where:

UNC_t	Total project uncertainty in year *t*, in %
$\Delta C_{BSL,t}$	Change in the baseline carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section C3)
UNC_{BSL}	Baseline uncertainty, in % (Section C5)
$\Delta C_{P,t}$	Change in the project carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section D5)
$UNC_{P,t}$	With-project uncertainty in year *t*, in % (Section D8)

If calculated *UNC* in equation (19) is <10%, then *UNC* shall be considered 0% in equation (20).

G. CALCULATION OF ERTs

This section describes the process of determining additional annual net greenhouse gas emission reductions and Emission Reduction Tons (ERTs) issued for a time period for which a valid verification report has been filed with ACR. Annual net greenhouse gas emission reductions ($C_{ACR,t}$) are calculated using equation 20 by adjusting the difference between the project and baseline carbon stock changes for leakage and uncertainty then multiplying by a non-permanence buffer deduction.

$$ERT_t = C_{ACR,t} = (\Delta C_{P,t} - \Delta C_{BSL,t}) \cdot (1 - LK) \cdot (1 - UNC_t) \cdot (1 - BUF) \quad (20)$$

where:

ERT_t	Emission Reduction Tons issued with vintage year t.
$C_{ACR,t}$	Annual net greenhouse gas emission reductions (in metric tons CO_2e) at time *t.*
$\Delta C_{P,t}$	Change in the project carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section D5)
$\Delta C_{BSL,t}$	Change in the baseline carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section C3)
LK	Leakage discount (Section D7)
UNC_t	Total Project Uncertainty, (in %) for year *t* (Section F3). UNC_t will be set to zero if the project meets ACR's precision requirement of within ±10% of the mean with 90% confidence. If the project does not meet this precision target, UNC_t should be the half-width of the confidence interval of calculated net GHG emission reductions.
BUF	The non-permanence buffer deduction as calculated in Section B5. *BUF* will be set to zero if an ACR approved insurance product is used.

Negative project stock change ($C_{ACR,t}$) before the first offset credit issuance is a negative balance of greenhouse gas emissions. After the first offset issuance, negative project stock change is a Reversal. AFOLU reversals must be reported and compensated following requirements detailed in the Reversal Risk Mitigation Agreement and the Buffer Pool Terms and Conditions, Exhibit 1 of the *ACR Standard, Version 5.0*. As outlined in Exhibit 1, sequestration projects will terminate automatically if a Reversal causes project stocks to decrease below baseline levels prior to the end of the Minimum Project Term.

American Carbon Registry
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METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

THE RESTORATION OF CALIFORNIA DELTAIC AND COASTAL WETLANDS

VERSION 1.1

November 2017

WINROCK INTERNATIONAL

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November 2017

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ACKNOWLEDGEMENTS

This methodology was authored by Steven Deverel (HydroFocus, Inc.), Patricia Oikawa (U.C. Berkeley), Sabina Dore (Hydrofocus, Inc.), Sarah Mack (Tierra Resources), and Lucas Silva (University of Oregon), with technical support from Dennis Baldocci (U.C. Berkeley) and Joe Verfaillie (U.C. Berkeley).

The authors are thankful to the large group of people who have contributed to the production of this methodology. Initial methodology development was led and convened by Belinda Morris (formerly of the American Carbon Registry) and Campbell Ingram of The California Sacramento-San Joaquin Delta Conservancy (DC). This resulted in funding for methodology development and approval from a consortium of partners including the California Department of Water Resources (DWR), the California Coastal Conservancy, the Metropolitan Water District of Southern California (MWD), and Sacramento Municipal Utilities District (SMUD). The Writing Team, Technical Working Group members and stakeholders have been instrumental in shaping the methodology by providing helpful comments, coordination, and insight. We are grateful to; Evyan Borgnis (California Coastal Conservancy), Bryan Brock (DWR), John Callaway (University of San Francisco), Judy Drexler (USGS), Matt Gerhart (California Coastal Conservancy), Sara Kroopf (Environmental Defense Fund), Campbell Ingram (DC), Michelle Passero (The Nature Conservancy), Russ Ryan (MWD), and Lisa Marie Windham-Meyers (USGS). Margaret Williams, Kyle Hemes, Jessica Orrego, and Lauren Nichols of the American Carbon Registry have provided many helpful comments and suggested changes during the writing, approval and publication process. HydroFocus hydrologists Tim Ingram and Kristyn Hanson helped greatly with editing and formatting.

The following methodologies were used to provide input to the methodology structure and text:

- ACR Restoration of Degraded Deltaic Wetlands of the Mississippi Delta, v 2.0
- VCS Methodology for Coastal Wetland Creation, v1.0
- ACR Emission Reductions Methodology in Rice Management Systems, v1.0

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ACRONYMS

ACR	American Carbon Registry
A/R	Afforestation and/or reforestation
ARR	Afforestation, reforestation, and revegetation
AFOLU	Agriculture, forestry, and other land use
C	Carbon
CDM	Clean development mechanism
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CF	Carbon fraction
CH_4	Methane
ERT	Emission Reduction Ton
GHG	Greenhouse gas
GIS	Geographic information system
GPS	Global positioning system
GWP	Global warming potential
N_2O	Nitrous oxide
MT	Metric ton
QA	Quality assurance
QC	Quality control
SOP	Standard Operating Procedures
VCS	Verified Carbon Standard
W/RC	Wetlands/Rice Cultivation

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1 METHODOLOGY FRAMEWORK MODULE (MF-W/RC)

PREFACE

The objective of this methodology is to describe quantification procedures for the reduction of greenhouse gas (GHG) emissions through conversion of land to wetlands and rice cultivation in the Sacramento-San Joaquin Delta, San Francisco Bay Estuary, and coastal areas of California. This methodology allows for GHG emission reductions and GHG sink enhancements by 1) halting or greatly reducing soil organic carbon oxidation on subsided and/or drained agricultural lands and 2) increasing soil organic carbon storage by restoring wetlands (tidal and non-tidal). The methodology is focused on subsided and/or drained agricultural lands with high organic soil contents in California, the majority of which are located in the San Joaquin-Sacramento Delta ("the Delta") and San Francisco Bay Estuary regions. Although this methodology is applicable throughout California, this methodology document by default places emphasis on the Delta and San Francisco Bay Estuary regions due to the large amount of research, measurements, and models needed to support GHG quantification having been conducted or developed in this region. Additional models, measurements, and supporting information from other regions will be incorporated into the methodology as available.

The methodology has been written in a modular format; Project Proponents can choose the applicable modules for their specific Project and site. The Framework Module provides background and an overarching description of the methodology requirements and modules. All Projects must meet the requirements outlined in the Framework Module. The remaining modules provide guidance for Baseline and Project Scenario GHG flux quantification, modeling, calculation of uncertainty, and other quantification tools. From these supporting modules, Project Proponents can select the relevant components for their Projects.

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes to project activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the Methodology.

1.1 BACKGROUND

The objective of this methodology is to describe quantification procedures for reducing greenhouse gas (GHG) emissions through conversion of land to wetlands and rice cultivation that

can be applied in areas such as the Sacramento-San Joaquin Delta, San Francisco Bay Estuary, and coastal areas of California.

Baseline or business-as-usual scenarios include agriculture, seasonal wetlands, and open water areas, where Baseline carbon stock changes and GHG emissions result primarily from the oxidation of organic matter (Table 1). Project Scenarios include tidal wetland restoration; managed, permanently flooded, non-tidal wetlands; and rice cultivation. These activities stop or greatly reduce Baseline emissions and, in the case of managed wetlands, can be net GHG sinks.

Table 1: Relevant Land Use, San Francisco Bay-Delta Examples, and GHG Impact

A list of relevant land uses and examples of each.

	LAND USE	EXAMPLES	PRIMARY GHG IMPACT
BASELINE	Agricultural	Farmed organic soils on Delta islands	GHG emissions due to oxidation of organic soils and fertilization. Primary GHG is CO_2, then N_2O
	Agricultural/ fallow/seasonal wetlands	Fallow areas or areas that have become impractical to farm due to excessive wetness in the Sacramento-San Joaquin Delta	GHG emissions due to oxidation of organic soils. Primary GHG is CO_2. There are likely N_2O and CH_4 emissions.
	Seasonal wetlands	Seasonally flooded hunting clubs in Suisun Marsh	GHG emissions due to oxidation of organic soils. Primary GHG is CO_2. There are also likely CH_4 and possible N_2O emissions.
	Open water	Subsided salt ponds in the South Bay, Franks Wetland in the Delta	Likely net GHG emissions
PROJECT	Managed, non-tidal wetlands	Twitchell and Sherman islands	Generally net GHG removal results from CO_2 sequestration minus CH_4 emissions
	Tidal wetlands	Rush Ranch, Suisun Marsh and others cited in Callaway and others (Callaway et al. 2012)	Net GHG removal where CO_2 sequestration (biomass production) is not offset by CH_4 and possibly N_2O emissions

LAND USE	EXAMPLES	PRIMARY GHG IMPACT
Rice	Twitchell Island, Wright Elmwood Tract, Brack Tract, Rindge Tract, Canal Ranch Tract, Delta	Net GHG emissions. CO_2 sequestration is offset by harvest carbon export and small CH_4 and N_2O emissions. Compared to other crops, provides GHG emission reductions due to reduced oxidation of organic soils.

For definition of land uses, see sections 1.1.1 and 1.1.2.

In the following paragraphs, example Baseline and Project activities are summarized. Projects in other areas in California that have similar conditions would also be eligible.

1.1.1 Baseline Condition Examples

Although isolated areas of drained and/or subsided agricultural lands with high organic soil content are present along the California coast, the majority and most studied of these areas are found in the Delta and San Francisco Bay Estuary. The following sections describe Baseline (BL) conditions in the Delta and San Francisco Bay region for the three Baseline Scenario types allowed in this methodology: 1) Agricultural lands (BL-Ag); 2) Seasonal Wetlands (BL-SW); and 3) Open Water (BL-OW).

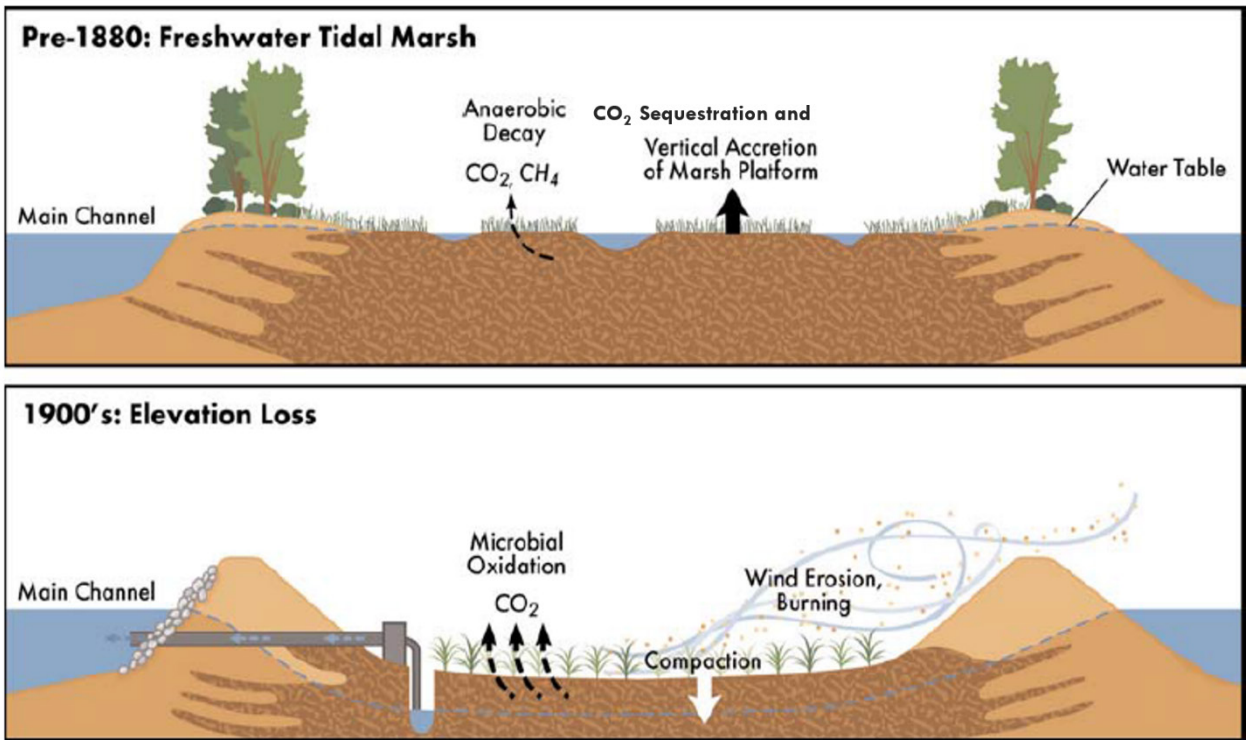
1.1.1.1 (BL-AG) AGRICULTURAL LANDS IN THE SACRAMENTO-SAN JOAQUIN DELTA

A key target area for implementing carbon sequestration in wetlands and rice cultivation is within the 750,000-acre (30,375 ha) Sacramento-San Joaquin Delta. The Delta is a critical natural resource, an important agricultural region and the hub for California's water supply. Since Delta islands were first diked and drained for agriculture in the late 1800s, more than 3.3 billion cubic yards (2.5 billion m^3) of organic soils have disappeared. This loss has resulted in land surface elevations as low as 20–25 feet (6–7.5 m) below sea level (Figure 1). During the last 6,800 years, organic soils accreted in a vast tidal marsh as sea level rose. Draining agricultural lands resulted in subsidence and loss of soil organic matter. Deverel and Leighton (2010) estimated that compaction was generally less than 30% of the total subsidence due to deepening of drainage ditches. The volume below sea level (accommodation space) of approximately 1.7 million acre feet (2.1 km^3) represents a significant opportunity for carbon sequestration.

The primary Baseline GHG emissions for this target area are due to the oxidation of organic matter in farmed and grazed organic and highly organic mineral soils. This oxidation primarily results in the emission of CO_2. Relatively small amounts of CH_4 are emitted due to anaerobic

decomposition of organic matter below the water table. Also, N_2O is emitted as the result of organic matter oxidation and fertilizer use. These emissions have occurred since the late 1800s due to drainage and cultivation of these soils. Baseline emissions of CO_2, CH_4, and N_2O have been measured and modeled. Specific information and a data summary are provided in Appendix B.

Figure 1: Evolution of Delta Subsided Islands (Modified from Mount and Twiss 2005)



1.1.1.2 (BL-SW) SEASONAL WETLANDS IN THE SAN FRANCISCO BAY ESTUARY

In the San Francisco Bay region, the primary Baseline GHG emission is due to the oxidation of soil organic matter in seasonal wetlands managed for recreational use (such as hunting) on organic and highly organic mineral soils. Some seasonal wetlands in the Sacramento-San Joaquin Delta are not managed but are merely too wet to farm. This oxidation results in emissions of CO_2, CH_4, and possibly N_2O. Consistent with the description of the oxidation of drained organic soils above, in an evaluation of different wetland management practices on highly organic mineral soils, US Geological Survey (USGS) researchers determined that seasonal wetlands (flooded during late fall, winter, and early spring) resulted in a net GHG emission (Deverel et al. 1998; Miller et al. 2000). Consistently, there are large areas of organic and

highly organic mineral soils that have subsided. For example, the Suisun Marsh area is composed of both organic and mineral soils. Reported organic matter content for these soils ranges from 15 to 70% (Bates 1977).

Most of the lands within the Suisun Marsh consists of diked wetlands that are flooded part of the year. Approximately 85% of these wetlands are drained from mid-July through mid-September when soil temperatures and organic matter oxidation rates are high. In Suisun Marsh, estimated median subsidence rates from the late 1940s to 2006 varied by soil type and ranged up to 2.5 cm $year^{-1}$ and were generally proportional to soil organic matter content (HydroFocus Inc. 2007). The estimated volume below sea level based on the 2006 LIDAR data is 5,800 acre feet (7,150,000 m^3) (HydroFocus Inc. 2007). This is the approximate volume of organic soil that has been lost since initial diking and drainage. There have been few Baseline measurements or estimates of GHG emissions in the Suisun Marsh or northern San Francisco Bay area. Recently, the USGS deployed an eddy covariance tower at the Rush Ranch wetland in Suisun Marsh to measure GHG fluxes.

1.1.1.3 (BL-OW) OPEN WATER IN THE SAN FRANCISCO BAY

An example area for applying this module is the San Francisco Bay where diked and managed salt ponds preserved a large area of shoreline in an open state for salt crystallization. Former salt ponds are now open water areas that are undergoing phased conversion to tidal wetlands (www.southbayrestoration.org). Over 15,000 acres (6,000 ha) have been reconnected to the bay or adjacent sloughs. Due to groundwater pumping in this area, many of the areas are substantially below sea level. These subsided lands are potentially influenced by processes that occur outside the Project boundaries. For example, allochthonous carbon (carbon originating outside the Project boundary) can enter the subsided areas via aqueous fluxes of particulate and dissolved organic carbon and be deposited in the Project area. Also, there can be large primary productivity and respiration rates in these open water areas, thus demonstrating the potential for Baseline GHG emissions and removals (Thébault et al. 2008).

1.1.2 Project Condition Examples

The following sections describe conditions following Project activities in the Delta and San Francisco Bay region for the three Project Scenario (PS) types allowed in this methodology: 1) Managed Wetlands (PS-MW); 2) Tidal Wetlands (PS-TW); and 3) Rice Cultivation (PS-RC).

1.1.2.1 (PS-MW) MANAGED, PERMANENTLY FLOODED, NON-TIDAL WETLANDS ON SUBSIDED AGRICULTURAL LANDS

The unique, chemically reducing environment in managed, permanently flooded wetlands on subsided lands facilitates CO_2 sequestration and methanogenesis (production of CH_4). In per-

manently flooded wetlands, CO_2 accumulates in plant tissues, which becomes litter and eventually accumulates as soil organic matter (SOM). The SOM can be converted to dissolved organic carbon (DOC), bicarbonate (HCO_{3-}), and CH_4. Dissolved organic carbon and CH_4 are byproducts of and leakages from the net accumulation of SOM and CO_2 sequestration.

Wetlands may be considered a GHG sink as CO_2 is removed from the atmosphere and stored in the soil carbon pool. However, a wetland also acts as a GHG source because it emits CH_4, which contributes to atmospheric radiative forcing. N_2O is not typically emitted from permanently flooded wetlands where water levels are greater than 10 cm (Smith et al. 1983). In general, the amount of CO_2 sequestered relative to the amount of CH_4 emitted and the relative ability of these gases to absorb infrared radiation ultimately determine whether the wetland is a sink or source for the global warming potential. Carbon fixation in the form of primary production is intimately connected with CH_4 production; the amount of CO_2 fixed on a daily basis has been positively correlated with CH_4 emissions (Whiting and Chanton 1993). The correlation of CH_4 emissions with Net Ecosystem Productivity is due to increases in organic substrates associated with root exudates, litter production, and plant turnover (Whiting and Chanton 2001). Since the late 1980s, there has been substantial interest in stopping and reversing the effects of subsidence by creating managed wetlands on subsided islands in the Sacramento-San Joaquin Delta. Additional information is provided in Appendix B.

1.1.2.2 (PS-TW) TIDAL WETLANDS IN SAN FRANCISCO BAY ESTUARY, SAN FRANCISCO BAY, AND THE CALIFORNIA COAST

Reported GHG removal rates across or within tidal wetland complexes vary widely and are affected by local plant community composition and productivity, decomposition rates, allochthonous sediment imports, salinity, tidal range, and human activities. There are several large-scale restoration Projects underway or planned in the San Francisco Bay Estuary (e.g., Montezuma Wetlands in Suisun Bay, Hamilton Wetlands, the Napa-Sonoma Salt Pond Project, and the South Bay Salt Pond Project) and elsewhere (e.g., Bolsa Chica Wetlands in Huntington Beach and San Dieguito Lagoon in San Diego). In the San Francisco Bay Estuary, tidal wetlands are mostly dominated by perennial pickleweed, Sarcocornia pacifica. Using two different dating systems (cesium-137 and lead-210), Callaway et al. 2012 reported long-term carbon sequestration rates in the San Francisco Bay Estuary ranging from 0.6 to 2.8 MT CO_2e $acre^{-1}$ $year^{-1}$ (1.5 to 6.9 MT CO_2e ha^{-1} $year^{-1}$). The average long-term carbon sequestration rate for tidal salt and brackish wetlands was 1.6 MT CO_2e $acre^{-1}$ $year^{-1}$ (3.9 MT CO_2 e ha^{-1} $year^{-1}$). Drexler (2011) estimated millennial rates ranging from 0.6 to 1.1 MT CO_2e $acre^{-1}$ $year^{-1}$ (1.5 to 2.7 MT CO_2e ha^{-1} $year^{-1}$) in remnant freshwater and brackish tidal marshes in the Delta. CH_4 emissions are minimal or nil where wetland water salinity values are over 18 parts per thousand (Poffenbarger et al. 2011). Similar to managed wetlands, N_2O can be nil from tidal wetlands (Moseman-Valtierra 2011, 2012; Badiou et al. 2011; Wang et al. 2017; Yu et al. 2007; Liikanen et al 2009).

1.1.2.3 (PS-RC) RICE CULTIVATION ON SUBSIDED AGRICULTURAL LANDS

Within the last 20 years, development of new rice varieties tolerant to low air and water temperatures resulted in Delta rice production with yields comparable to the Sacramento Valley. Available data indicate the combination of in-season and off-season flooding and addition of rice residues stop or greatly reduce oxidative soil loss. Rice has been successfully grown on over 3,000 acres on Delta islands for over 10 years. Data reported for CO_2 and CH_4 emissions in rice by Hatala et al. (2012) and Knox et al. (2015) and N_2O data reported by Ye and Horwath (2016a) demonstrate there is net GHG benefit for conversion to rice where soil organic carbon values range from 5 to 25%.

1.1.3 Geographic Applicability

Due to the unique conditions described for the Sacramento-San Joaquin Delta and San Francisco Bay Estuary, the methodology has been developed envisioning the majority of Projects occurring in these geographic areas. The methodology focuses on areas where the available data demonstrate high GHG emissions and the potential for net GHG emissions reductions. These include managed non-tidal wetlands and rice where there are Baseline GHG emissions due to the oxidation of organic soils, and tidal wetlands where salinity inhibits CH_4 emissions. However, it may be used without modification for areas throughout California where data indicate the potential for GHG emission reductions. Figure 2 shows the boundaries of the Delta and San Francisco Bay, where areas of the three applicable Project types are located.

Figure 2: Locations of Primary Applicable Areas for Projects Using this Methodology



1.2 GENERAL GUIDANCE

1.2.1 Scope

The Modules and Tools described here are applicable for quantification of GHG removals and emission reductions for restoration of managed, permanently flooded, non-tidal wetlands (MW); tidal wetlands (TW); and rice cultivation (RC) in the eligible geographies. The water quality of

eligible activities ranges from fresh to saline and includes agricultural lands, managed or non-managed seasonal wetlands, and open water.

This methodology does not provide technical guidance for wetland construction, restoration, rice cultivation, or any Project-related implementation. These activities require the expertise of designated experts such as (but not restricted to) certified wetland scientists, agronomists, hydrologists, and civil and environmental engineers. The methodology assumes that the Project Proponent has or engages the necessary expertise and requires that the activities implemented under this methodology comply with all applicable local, state, and national laws and regulations.

Unless otherwise specified in this methodology, all Projects are subject to the requirements described in the current version of the ACR Standard[1] in addition to the requirements of this methodology.

1.2.2 Modules and Tools

The modules and tools available for use are listed in Table 2. Table 3 lists module requirements for the three project scenarios.

Table 2: Available Modules and Tools for Quantifying GHG Emissions

METHODOLOGY FRAMEWORK MODULE	
MF-W/RC	Framework Module for the Wetlands and Rice Cultivation methodology. Includes requirements applicable to all projects, regardless of Baseline or Project condition and describes how other modules should be used.
BASELINE MODULES	
BL-AG	Estimation of agricultural Baseline carbon stock changes and GHG emissions when there are agricultural activities in place prior to the Project commencement date. Project activity includes wetland construction (managed or tidal) or rice cultivation.
BL-SW	Estimation of Baseline carbon stock changes and GHG emissions when there are managed and non-managed seasonal wetlands in place prior to the Project commencement date. Project activity includes wetland construction (managed or tidal) or rice cultivation.

[1] See americancarbonregistry.org

BL-OW	Estimation of Baseline carbon stock changes and GHG emissions when there is open water in place prior to the Project commencement date. Project activity includes wetland construction (tidal only).

PROJECT MODULES

PS-MW	Estimation of Project Scenario carbon stock changes and GHG emissions for construction of managed, permanently flooded, non-tidal wetlands. Project activity includes hydrologic management, infrastructural modification, and plantings or natural plant regeneration.
PS-TW	Estimation of Project Scenario carbon stock changes and GHG emissions from construction and restoration of tidal wetlands. Project activity may include levee breaching to create tidal influence, plantings, fill, and salt flushing.
PS-RC	Estimation of Project Scenario carbon stock changes and GHG emissions from rice cultivation. Project activity includes rice cultivation and may include hydrologic management and infrastructural modification.

METHOD MODULES

MM-W/RC	Methods for estimating carbon stocks and GHG emissions.
E-FFC	Methods for estimating annual GHG emissions from fossil fuel combustion.
MODEL-W/RC	Biogeochemical models that can be used for estimation of carbon stock changes and GHG emissions under specified Baseline and Project conditions.
X-UNC	Estimation of uncertainty.

TOOLS

T-SIG	Tool for testing significance of GHG emissions in A/R CDM Project activities.
T-RISK	The currently approved ACR permanence risk tool.
T-PLOTS	Calculation of the number of sample plots for measurements within A/R CDM Project activities.

Table 3: Determination of Mandatory (M), Conditional (C), or Not Required (N/R) Module/Tool Use

Modules marked with an M are mandatory: the indicated Modules and Tools must be used. Modules marked with a C are conditional depending on the Baseline and Project Scenario. Modules marked with N/R are not required.

DETERMINATION	MODULE/ TOOL	MANAGED WETLAND CONSTRUCTION	TIDAL WETLAND RESTORATION	RICE CULTIVATION
Used by All Projects	Framework	M	M	M
	T-RISK	M	M	M
	X-UNC	M	M	M
	Model-W/RC	C	C	C
	MM-W/RC	M	M	M
	E-FFC	C	C	M
	T-PLOTS	C	C	C
	T-SIG	M	M	M
Baselines	BL-Ag	C	C	M
	BL-SW	C	C	C
	BL-OW	C	C	N/R
Project Scenarios	PS-MW	M	N/R	N/R
	PS-TW	N/R	M	N/R
	PS-RC	N/R	N/R	M

1.2.3 Verification

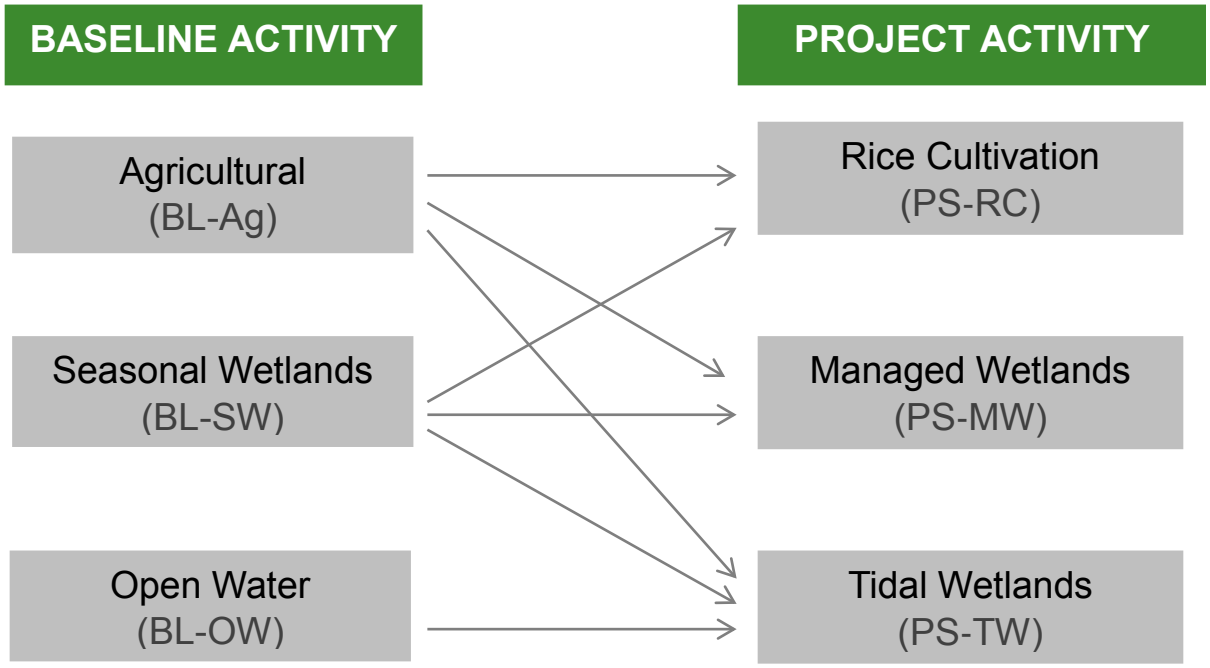
As conditions governing emissions and removals are highly variable in space and time in wetland environments, this methodology requires that Project Proponents demonstrate that models and measurements are appropriately applied to the Project site. Consequently, this methodology requires that the verification team includes at least one hydrologist, biogeochemist or professionals with biogeochemical modeling experience in the Delta or similar peatland systems.

The list of currently available measurements and models can be found in the Methods Module (MM-W/RC and MODEL-W/RC). This list will be updated as additional measurements and bio-geochemical models become available or the geographic range where existing models have been calibrated and validated is expanded.

1.2.4 Eligible Project and Baseline Combinations

Figure 3: Project and Baseline Modules

Figure 3 shows the relationships between Project and Baseline Modules. Project activities can be employed depending on Baseline conditions. The rice cultivation and managed wetland Project activities can only be applicable with an agricultural or seasonal wetlands Baseline. Tidal wetland is applicable with all Baseline Scenarios.



1.2.5 Applicability Criteria

Project Proponents must demonstrate to ACR and the Verifier that they have met the applicability conditions in the Framework Module, in any other modules utilized, and any overarching eligibility criteria set forth in the current version of the ACR Standard. The GHG Project Plan shall justify the use of modules relevant to the proposed Project activities.

Table 4 to Table 11 list applicability conditions for each possible Baseline-Project pair.

Table 4: Ineligible Activities in All Project Scenarios

ALL SCENARIOS – INELIGIBLE ACTIVITIES
• Draining of wetland soils
• Activities that cause deleterious impacts or diminish the GHG sequestration function of habitat outside the Project area
• Activities that result in reduction of wetland restoration activities or increase wetland loss outside the Project area
• Activities required under any law or regulation, including Section 404 of the Clean Water Act to mitigate onsite or offsite effects of wetlands
• Activities that involve the use of natural resources within the Project boundary that lead to further environmental degradation (activities such as fishing and hunting that are conducted in a manner that does not lead to degradation are allowed)
• Planting of non-native species
• Harvesting of wood products*
• Activities affecting fish populations in Delta channels

* As meeting the definition for wood products in the ACR Forestry Standard and/or the definition for tree in the ACR Methodology for the Avoided Conversion of Grasslands.

Table 5: Applicability Criteria for Baseline-Project Pair Scenario 1

SCENARIO 1	
AGRICULTURE (BASELINE CONDITION)	**MANAGED WETLAND (PROJECT CONDITION)**
• Land is within the State of California • Land is not precluded from restoration activities and ongoing wetland management through regulation, easements, or mitigation obligations • Land must be used for agriculture or grazing for 6 out of 10 years prior to Project start date • Project area is one continuous parcel or multiple discrete parcels with all parcels meeting applicability criteria and all parcels within the State of California • Approved biogeochemical model, or published measurement data, or published method applicable to the site is available for estimating Baseline emissions from agriculture for the Project area*	• Restored wetland areas are non-tidal • Land is permanently flooded with surface water levels at land surface or up to 1 meter above land surface • Project activity includes any of the following: alteration of hydrologic conditions, sediment supply, water quality, plant communities and nutrients; hydrologic management; infrastructural modification, earth moving; diversion of channel water into wetlands; management of surface water levels and wetlands outflow; plantings, seeding, or natural plant regeneration; or levee breaching (permitted) • Restoration activity meets federal, state, local regulations and permit requirements • Approved biogeochemical model, or published measurement data, or published method applicable to the site are available for estimating Project carbon stock changes and GHG emissions from managed wetlands* • Must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of wetland for the duration of minimum Project term**

* See the Methods Module for a description of currently available models and measurements. The model and method list will be regularly updated.

** Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

Table 6: Applicability Criteria for Baseline-Project Pair Scenario 2

SCENARIO 2	
AGRICULTURE (BASELINE CONDITION)	**TIDAL WETLAND (PROJECT CONDITION)**
• Land is within the State of California • Land is not precluded from restoration activities and ongoing wetland management through regulation, easements, or mitigation obligations • Land must be used for agriculture or grazing for 6 out of 10 years prior to Project start date • Project area is one continuous parcel or multiple discrete parcels with all parcels meeting applicability criteria and all parcels within the State of California • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Baseline emissions from agriculture for the Project area*	• Restoration creates tidal marshes or eelgrass meadows within the State of California • Land must not receive nitrogen fertilizer or manure during the Project period • Project activity includes: hydrologic management, infrastructure modification, levee breaching (permitted), levee construction, earth-moving, planting, application of dredged material, and other activities related to re-introduction of tidal activity • Restoration activity meets federal, state, local regulations and permit requirements • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Project GHG emissions and carbon stock changes in tidal wetlands* • Must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of wetland for the duration of minimum Project term**

* See the Methods Module for a description of currently available models and measurements. The model and method list will be regularly updated.

** Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

Table 7: Applicability Criteria for Baseline-Project Pair Scenario 3

SCENARIO 3	
AGRICULTURE (BASELINE CONDITION)	**RICE CULTIVATION (PROJECT CONDITION)**
• Land is within the State of California • Land is not precluded from restoration activities and ongoing wetland management through regulation, easements, or mitigation obligations • Land must be used for agriculture or grazing for 6 out of 10 years prior to Project start date • Project area is one continuous parcel or multiple discrete parcels with all parcels meeting applicability criteria and all parcels within the State of California • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Baseline emissions from agriculture for the Project area*	• Straw burning and removal of agricultural crop residues is not allowed • Project activity includes: hydrologic management, infrastructure modification, levee breaching (permitted), levee construction, earth-moving, planting, diversion of channel water into rice fields • Restoration activity meets federal, state, local regulations and permit requirements • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Project carbon exchanges and GHG emissions from rice cultivation* • Must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of rice cultivation for the duration of minimum Project term**

* See the Methods Module for a description of currently available models and measurements and applicable geographic region. The model and method list will be regularly updated.

** Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

Table 8: Applicability Criteria for Baseline-Project Pair Scenario 4

SCENARIO 4	
SEASONAL WETLAND (BASELINE CONDITION)	**MANAGED WETLAND (PROJECT CONDITION)**
• Land is within the State of California • Land is not precluded from restoration activities and on-going wetland management through regulation, easements or mitigation obligations • Land is subsided and dry for a minimum 4 months per year and where dry periods result in continued organic soil loss • Project area is one continuous parcel or multiple discrete parcels with all parcels meeting applicability criteria and all parcels within the State of California • Approved biogeochemical model or published measurement data or published method applicable to the site is available for estimating Baseline emissions from seasonal wetlands*	• Restored wetland areas are non-tidal • Land is permanently flooded with surface water levels at land surface or up to 1 meter above land surface • Project activity includes any of the following: alteration of hydrologic conditions, sediment supply, water quality, plant communities and nutrients; hydrologic management; infrastructural modification, earth moving; diversion of channel water into wetlands; management of surface water levels and wetlands outflow; plantings, seeding, or natural plant regeneration; or levee breaching (permitted) • Restoration activity meets federal, state, local regulations and permit requirements • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Project carbon stock changes and GHG emissions and from managed wetlands* • Must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of wetland for the duration of minimum Project term**

* See the Methods Module for a description of currently approved models and methods. The model and method list will be regularly updated.

** Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

Table 9: Applicability Criteria for Baseline-Project Pair Scenario 5

SCENARIO 5	
SEASONAL WETLAND (BASELINE CONDITION)	**TIDAL WETLAND (PROJECT CONDITION)**
• Land is within the State of California • Land is not precluded from restoration activities and on-going wetland management through regulation, easements or mitigation obligations • Land is subsided and dry for a minimum 4 months per year and where dry periods result in continued organic soil loss • Project area is one continuous parcel or multiple discrete parcels with all parcels meeting applicability criteria and all parcels within the State of California • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Baseline GHG emissions from seasonal wetlands*	• Restoration creates tidal marshes or eelgrass meadows within the State of California • Land must not receive nitrogen fertilizer or manure during the Project period • Project activity includes: hydrologic management; infrastructure modification; levee breaching (permitted); levee construction; earth moving; planting; application of dredged material; other activities related to re-introduction of tidal activity • Restoration activity meets federal, state, local regulations and permit requirements • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Project carbon stock changes and GHG emissions in tidal wetlands* • Must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of wetland for the duration of minimum Project term**

* See the Methods Module for a description of currently available model and measurements and applicable geographic region. The model and method list will be regularly updated.

** Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

Table 10: Applicability Criteria for Baseline-Project Pair Scenario 6

SCENARIO 6	
SEASONAL WETLAND (BASELINE CONDITION)	**RICE CULTIVATION (PROJECT CONDITION)**
• Land is within the State of California • Land is not precluded from restoration activities and on-going wetland management through regulation, easements or mitigation obligations • Land is subsided and dry for a minimum 4 months per year and where dry periods result in continued organic soil loss • Project area is one continuous parcel or multiple discrete parcels with all parcels meeting applicability criteria and all parcels within the State of California • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Baseline GHG emissions from seasonal wetlands*	• Straw burning and removal of agricultural crop residues is not allowed • Project activity includes: hydrologic management, infrastructure modification, levee breaching (permitted), levee construction, earth-moving, planting, diversion of channel water into rice fields • Restoration activity meets federal, state, local regulations and permit requirements • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Project carbon exchanges and GHG emissions from rice cultivation* • Must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of rice cultivation for the duration of minimum Project term**

* See the Methods Module for a description of currently available model and measurements and applicable geographic region. The model and method list will be regularly updated.

** Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

Table 11: Applicability Criteria for Baseline-Project Pair Scenario 7

SCENARIO 7	
OPEN WETLAND (BASELINE CONDITION)	**TIDAL WETLAND (PROJECT CONDITION)**
• Open water within the State of California • Land is permanently submerged with 90% of its area having a depth that does not support emergent vegetation, and there is no more than 10% of sparse vegetation • Land is not precluded from restoration activities and ongoing wetland management through regulation, easements or mitigation obligations • Project area is one continuous parcel or multiple discrete parcels with all parcels meeting applicability criteria and all parcels within the State of California • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Baseline GHG emissions from open water*	• Restoration creates tidal marshes or eelgrass meadows within the State of California • Land must not receive nitrogen fertilizer or manure during the Project period • Project activity includes: hydrologic management; infrastructure modification; levee breaching (permitted); levee construction; earth moving; planting; application of dredged material; other activities related to re-introduction of tidal activity • Restoration activity meets federal, state, local regulations and permit requirements • Approved biogeochemical model, or published measurement data or published method applicable to the site is available for estimating Project carbon stock changes and GHG emissions in tidal wetlands* • Must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of wetland for the duration of minimum Project term**

* See the Methods Module for a description of currently available models and methods. The model and method list will be regularly updated.

** Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

The Project Proponents shall provide attestations and/or evidence (e.g., CEQA documentation, permits, or permit applications) of environmental compliance to the ACR at the time of GHG Project Plan submission, and to the validation/verification body at the time of validation, and at each verification. Any changes to the Project's regulatory compliance status shall be reported to ACR immediately.

1.3 ASSESSMENT OF NET GHG EMISSION REDUCTION

The Project Proponent shall implement the following steps to assess GHG emission reductions:

Step 1 Identification of the Baseline activities

Step 2 Definition of Project boundaries

Step 3 Demonstration of additionality

Step 4 Development of a Monitoring Plan

Step 5 Estimation of Baseline carbon stock changes and GHG emissions

Step 6 Estimation of Project carbon stock changes and GHG emissions

Step 7 Estimation of total net GHG emission reductions (Baseline minus Project and leakage)

Step 8 Calculation of uncertainty

Step 9 Risk assessment

Step 10 Calculation of Emission Reduction Tons (ERTs)

All steps are required ex-ante. For ex-post, steps 6 through 10 are applicable. For parameters that will be monitored or modeled subsequent to Project initiation, ex-post guidance is given in the relevant Methods Modules (MM-W/CR, MODEL–W/CR, and E-FFC).

A Proponent can stop a Project during its duration and replace it with a new Project. The new Project must be eligible and compatible with the original Baseline conditions. The Proponent needs to reassess Baseline conditions and quantify net GHG emission reduction following steps 1 to 10. In the estimation of new net GHG emission reductions (Step 7), the Baseline Scenario shall be identical to the Baseline Scenario assessed at the beginning of the original Project.

1.3.1 STEP 1 Identification of the Baseline Activities

Figure 3 can be used to identify the appropriate Baseline and Project Modules. A Project can include areas with different Baselines. In such cases, Project and Baseline areas shall be delineated in the GHG Project Plan.

Proponents must demonstrate that one of the permissible Baseline Scenarios is credible for their Project area by describing what would have occurred in absence of the Project Activities and quantifying GHG emissions and removals. The Baseline Scenarios must be limited to the specified Baseline land uses shown in Figure 3 and comply with the applicability conditions described in the Framework, Baseline, and Project Modules.

1.3.2 STEP 2 Definition of Project Boundaries

The following categories of boundaries shall be defined:

- The geographic boundaries relevant to the Project activity;
- The temporal boundaries;
- The carbon pools that the Project will consider;
- The sources and associated types of GHG emissions.

1.3.2.1 GEOGRAPHIC BOUNDARIES

The Project Proponents must provide a detailed description of the geographic boundary of Project activities using a Geographic Information System (GIS). Information to delineate the Project boundary may include:

- USGS topographic map or property parcel map where the Project boundary is recorded for all areas of land. Provide the name of the Project area (e.g., compartment number, allotment number, local name) and a unique ID for each discrete parcel of land;
- Aerial map (e.g., orthorectified aerial photography or georeferenced remote sensing image);
- Geographic coordinates for the Project boundary, total land area, and land holder and user rights.

Project Proponents shall provide a GIS shapefile that includes relevant geographic features and the Project boundaries.

Where multiple Baselines exist, there shall be no overlap between areas appropriate to each of the Baselines. Project activities may occur on more than one discrete area of land, but each area must meet the Project eligibility requirements. This methodology allows for aggregation following the ACR Standard. In a Programmatic Development Approach, new areas may be

added to an existing Project after the start of the crediting period as long as all the applicability criteria are met for each new area.

1.3.2.2 TEMPORAL BOUNDARIES

Project Start Date, Crediting Period, and Minimum Project Term are defined in the current version of the ACR Standard. Specific to this Project type, the Project Start Date is defined as the day Project Proponents began verifiable activities to increase carbon stocks and/or reduce GHG emissions. Specific to this Project type, a Minimum Project Term of 40 years is required and the Crediting Period is 40 years, over which time monitoring, reporting, and verification must take place to ensure the existence and the permanence of carbon stock increase and/or GHG emission reductions. Spatial and temporal patterns of tidal and freshwater wetlands are dynamic, resulting from complex and interactive effects of natural and human-induced processes. These factors shall be accounted for in Project monitoring and reporting.

1.3.2.3 CARBON POOLS AND SOURCES

Table 12 and Table 13 provide guidelines for determining the GHG assessment boundary. Exclusion of carbon pools and emission sources is allowed subject to considerations of conservativeness and significance testing, or when inclusion may result in double counting. This can be the case for plant litter, above- and below-ground non-woody biomass, and soil organic matter pools, or when GHG net exchanges are measured using a mix of approaches such as carbon stock changes, instantaneous fluxes measurements, and modelling. When modifying the IPCC guidance (2006) for measuring above- and below-ground living biomass, dead organic matter, and soil carbon pool, it is good practice to report upon them clearly, to ensure that definitions are used consistently, and to demonstrate that pools are neither omitted nor double-counted.

For example, in flooded ecosystems in the geographic applicability area that are characterized primarily by non-woody annual plants and highly organic soils, soil carbon stock changes can be used to quantify ecosystem carbon stock changes and CO_2 emissions. These plants die annually, determining the annual production of litter and the amount of C inputs into soils. When annual soil carbon stock changes are quantified, they already include changes in the biomass and litter pools. Above- and below-ground biomass, litter, and change in soil carbon stock do not need to be included repeatedly.

Pools or sources may always be excluded to be conservative, i.e., exclusion will tend to underestimate net GHG emission reductions. Pools, sinks, or sources can be excluded (i.e., counted as zero) if the application of the tool T-SIG indicates that each source, sink, and pool is determined to be insignificant and can be excluded from accounting, i.e., it represents less than 3%

of the ex-ante calculation of GHG emission reductions/removal enhancements (per the ACR Standard[2]).

Table 12: Carbon Pools to Be Considered for Monitoring or Modeling

CARBON POOL	STATUS	JUSTIFICATION/ EXPLANATION	QUANTIFICATION METHODS DESCRIBED IN THE METHODS MODULES (MM-W/RC, MODEL-W/RC)
Above-ground biomass	Required	May be excluded if already included in other pools, such as the soil carbon pool	• Biogeochemical models • Remote sensing • Leaf Area Index (LAI) determination and digital photography • Allometric and destructive methods • Peer-reviewed literature values
Below-ground biomass	Required	May be excluded if already included in other pools, such as the soil carbon pool	• Biogeochemical models • Field measurement • Literature values
Litter	Required	May be excluded if already included in other pools, such as the soil carbon pool	• Biogeochemical models • Litter bags • Literature values
Crop residue	Required if relevant	Must be included for agricultural Baseline and rice Project if shown to be significant May be excluded if subject to double-counting.	• Biogeochemical models • Field measurement

[2] See americancarbonregistry.org

CARBON POOL	STATUS	JUSTIFICATION/ EXPLANATION	QUANTIFICATION METHODS DESCRIBED IN THE METHODS MODULES (MM-W/RC, MODEL-W/RC)
Soil organic matter	Required	Must be included for all Baseline and Project Scenarios May be excluded if subject to double-counting.	• Field measurement • Biogeochemical models
Harvested biomass	Required if relevant	Required for agricultural Baseline and rice Project Scenarios	• Biogeochemical models • Measurement of harvested product

Table 13: Greenhouse Gas Sources and Sinks

	PROCESS	GAS	STATUS	JUSTIFICATION/ EXPLANATION	QUANTIFICATION METHODS DESCRIBED IN THE METHODS MODULES (MM-W/RC, MODEL-W/RC)
BASELINE	Production of CH_4 by bacteria	CH_4	Optional	May be conservatively excluded from Baseline emissions	Field measurement Biogeochemical model
	Nitrogen transformations due to fertilizer application or organic soil oxidation	N_2O	Optional	May be conservatively excluded from Baseline emissions	Field measurement Biogeochemical model
	Oxidation of organic soils	CO_2	Required	Primary Baseline emission	Field measurement Biogeochemical model
	Emissions from fossil fuel combustion	CO_2	Required	Primary Baseline emission	Calculations described in Methods (E-FFC)
		N_2O	Optional	May be excluded if shown to be insignificant	Calculations described in Methods (E-FFC)
		CH_4	Optional	May be excluded if shown to be insignificant	Calculations described in Methods (E-FFC)
	CO_2 sequestration by vegetation	CO_2	Required	Primary Baseline removal	Field measurement Biogeochemical model

	PROCESS	GAS	STATUS	JUSTIFICATION/ EXPLANATION	QUANTIFICATION METHODS DESCRIBED IN THE METHODS MODULES (MM-W/RC, MODEL-W/RC)
PROJECT	Production of CH_4 by bacteria	CH_4	Required	Primary emission for all Project Scenarios May be excluded in saline tidal marshes under conditions specified in the tidal wetland module (PS-TW)	Field measurement Biogeochemical model
	Nitrogen transformations due to fertilizer application or organic soil oxidation	N_2O	Required if relevant	Must be included for rice cultivation Optional for all other Project Activities if shown to be insignificant*	Field measurement Biogeochemical model
	Oxidation of organic soils	CO_2	Required	Must be included	Field measurement Biogeochemical model
	Emissions from fossil fuel combustion	CO_2	Required	May be excluded if justified by demonstrating that fossil fuel emissions for Project conditions or equal to or less than Baseline conditions	Calculations described in Methods (E-FFC)
		N_2O	Optional	May be excluded if shown to be insignificant	Calculations described in Methods (E-FFC)
		CH_4	Optional	May be excluded if shown to be insignificant	Calculations described in Methods (E-FFC)
	CO_2 sequestration by vegetation	CO_2	Required	Primary Project removal	Field measurement Biogeochemical models

* N_2O emissions can be ignored in permanently flooded wetland conditions. Under permanently flooded soil conditions, N_2O is consumed during denitrification and converted to N_2 (Butterbach-Bahl et al. 2013).

1.3.2.4 LEAKAGE ASSESSMENT

Leakage is an increase in GHG emissions outside the Project boundaries that occurs as a result of the Project action. ACR requires Project Proponents to assess, account for, and mitigate leakage above de-minimis levels. Project Proponents must deduct leakage that reduces the GWP benefit of a Project in excess of the threshold of 3%. Activity-shifting leakage occurs when the land uses resulting in Baseline emissions that operated in the Project area before the Project start date are relocated to another area outside of the Project boundary. Market-effects leakage is transmitted through market forces; a supply reduction can result in an increased price that may incentivize increased production and shifts in cropping patterns elsewhere. The change in the GWP as the result of this market-effects leakage shall be accounted for in the net Project GHG removals. For the activities included in this methodology, only agricultural market-effects leakage may result from replacement of crops currently grown in the Delta by wetlands and rice. All other Project Scenarios need no further leakage analysis and may use a leakage value of zero as it is assumed that there would be no leakage for non-agricultural Baselines.

As part of this methodology development, a leakage analysis was conducted for replacement of traditional crops in the Delta with wetlands and rice. First, an economic analysis was conducted to determine how crop acreages statewide would be affected by Delta land conversion. Next, a change in GWP was estimated as the result of this crop-area change. The report describing the leakage analysis is included in Appendix A.

Following this analysis, Managed Wetlands and Rice Projects implemented on agricultural lands that include less than 35,000 acres (14,200 ha) of crop land or 10,000 acres (4,000 ha) of pasture do not require leakage deduction. The leakage analysis shall be reviewed to determine if additional leakage analysis is required at 10 years after the approval of this methodology. Leakage analysis is required for implementation of the methodology in agricultural areas outside the Sacramento-San Joaquin Delta or if the cumulative acreage of wetlands and rice in the Sacramento-San Joaquin Delta exceeds the area described above.

1.3.2.5 STRATIFICATION

Stratification is a standard procedure to decrease overall variability of carbon stock and GHG emissions estimates by grouping environments with similar characteristics. If the area is not homogeneous, stratification shall be implemented to improve the accuracy and precision of carbon stock and GHG emissions estimates and achieve optimal accuracy of the estimates of net GHG emissions or removals. Different stratifications may be required for the Baseline and Project Scenarios, especially if there will be a change in hydrology, in order to achieve optimal accuracy and precision of the estimates of net GHG emission reductions. Within each module, specific guidelines are provided for stratification.

The stratification for ex-ante estimations shall be based on the content of the Project Monitoring Plan. The stratification for ex-post estimations shall be based on the actual implementation of

the Project Monitoring Plan. If natural or anthropogenic impacts (e.g., levee breaks and flooding) or other factors (e.g., altered hydrology or water management) add variability in the vegetation of the Project area, then the stratification shall be revised accordingly. Project Proponents may use remote sensing data acquired close to the time of Project commencement and/or the occurrence of natural or anthropogenic impacts for ex-ante and ex-post stratification.

Strata shall be delineated using spatial data (e.g., maps, GIS, or classified imagery). Strata must be spatially discrete and stratum areas must be known. Areas of individual strata must sum to the total Project Area.

1.3.3 STEP 3 Demonstration of Additionality

Eligible offsets must be generated by Projects that yield surplus GHG reductions that exceed any GHG reductions otherwise required by law or regulation or any GHG reduction that would otherwise occur in a conservative business-as-usual scenario. These requirements are assessed through the Legal Requirement Test and the Performance Standard Evaluation.

1.3.3.1 LEGAL REQUIREMENT TEST

Emission reductions achieved by Rice Cultivation or Wetland Projects must exceed those required by any law, regulation, or legally binding mandate as required in the jurisdiction where they are located. The following legal requirements apply to all Rice Cultivation and Wetland Projects:

- The activities that result in GHG emission reductions are not required by law, regulation, or any legally binding mandate applicable in the offset Project's jurisdiction, and would not otherwise occur in a conservative common practice business-as-usual scenario;
- If any law, regulation, or legally binding mandate requiring the implementation of Project Activities at the field(s) in which the Project is located exists, only GHG emission reductions resulting from the Project Activities that are in excess of what is required to comply with those laws, regulations, and/or legally binding mandates are eligible for crediting under this protocol.

1.3.3.2 PERFORMANCE STANDARD EVALUATION

Emission reductions achieved by a Rice Cultivation or Wetland Project must exceed those likely to occur in a conservative business-as-usual scenario and are subject to the following practice-based performance standard for wetlands and rice cultivation.

1.3.3.3 PRACTICE-BASED PERFORMANCE STANDARD

This methodology utilizes a practice-based performance approach for demonstrating additionality. The ACR Standard defines practice-based as "developed by evaluating the adoption rates or penetration levels of a particular practice within a relevant industry, sector or sub-sector. If these levels are sufficiently low that it is determined the Project activity is not common practice, then the Project activity is considered additional. Specific thresholds may vary by industry, sector, geography and practice, and are specified in the relevant methodology." The following practice-based performance standards are examples for the specific geographic applicability areas in the Sacramento-San Joaquin Delta and San Francisco Bay Estuary.

1.3.3.3.1 Managed, Permanently Flooded, Non-Tidal Wetlands on Subsiding Lands Where Organic and Highly Organic Mineral Soils Are Present in the Sacramento-San Joaquin Delta

Managed, permanently flooded, non-tidal wetlands on lands that were formally in agriculture currently represent less than 2% of the approximately 200,000 acres (81,000 ha) where organic and highly organic mineral soils are present and subsiding to various degrees in the Sacramento-San Joaquin Delta (Deverel et al. 2014). Costs for converting agricultural lands to managed non-tidal wetlands range from $600 (Merrill et al. 2010) to over $6,000 per acre (Brock 2011) ($1,300 to $13,000 per hectare). Because wetland restoration is not a common practice among Delta landowners, Managed Non-Tidal Wetland Projects using this methodology are deemed "beyond business as usual" and therefore additional. Thus, a Managed Non-Tidal Wetland Project that occurs on agricultural lands where there are organic or highly organic mineral soils satisfies the Practice-Based Performance Standard. There will likely be an increase in wetland acreage over time, which will change the results of the analyses used to establish and validate the performance standard. ACR reserves the right to review and require revisions to this performance standard as necessary at an interval no less frequent than once every 10 years following the approval of this Methodology.

1.3.3.3.2 Rice Cultivation on Subsiding Organic Soils and Highly Organic Mineral Soils in the Sacramento-San Joaquin Delta

Rice currently represents less than 3 percent of the approximately 200,000 acres (81,000 ha) where organic and highly organic mineral soils are present and subsiding to various degrees in the Sacramento-San Joaquin Delta. Costs for conversion of agricultural land farmed to traditional crops such as corn to rice range from $116 (Canivari et al. 2007) to over $1,000 per acre (Brock 2011) ($260 to $2,200 per hectare). Because conversion to rice cultivation is not common practice by Delta landowners, Projects using this methodology are deemed "beyond business as usual" and therefore additional. Therefore, a Rice Cultivation Project that occurs on agricultural land where there are organic or highly organic mineral soils satisfies the Practice-

Based Performance Standard. There will likely be additional rice acreage during the next decade. ACR reserves the right to review and require revisions to this performance standard as necessary at an interval no less frequent than once every 10 years following the approval of this Methodology.

1.3.3.3.3 Tidal Wetlands in San Francisco Bay Estuary

San Francisco Bay has lost an estimated 90 percent of its historic wetlands to fill or alteration (Okamoto and Wong, 2011). Tidal wetlands currently represent about 16% of the area historically covered by tidal wetlands in the San Francisco Bay Estuary (Baylands Ecosystem Habitat Goals Project 1999). The level of penetration in the remaining area of former tidal wetlands has been documented as low. For example, Callaway et al. (2011) documented the relatively small number and area of restoration projects that have been implemented in Suisun Bay and San Francisco Bay. In the historic wetland area of 190,000 acres (76,781 ha), 96 projects for mitigation and non-mitigation totaling 10,000 acres (4,069 ha) have been implemented. Figure 1 in Callaway et al. (2011) shows the relatively low level of penetration in San Francisco Bay Estuary. The level of penetration is calculated as a fraction of the maximum adoption potential. For tidal wetlands in San Francisco Bay Estuary, the maximum adoption potential is equal to 100,000 acres (40,500 ha) within the baylands in San Francisco Bay and Suisun Marsh.[3] Using the Callaway et al. (2011) estimate of 10,000 acres (4,069 ha) restored, the percent penetration is 10% or an average of about 0.3% per year since the mid-1970s when restoration began.

1.3.4 STEP 4 Developing of a Monitoring Plan

Project Proponents shall include a single Monitoring Plan in the GHG Project Plan. For monitoring changes in wetland cover and carbon stock changes, the Monitoring Plan shall use the methods given in the Methods Modules (MM-W/RC, MODEL-W/RC) and relevant Project Modules (PS-MW, PS-RC, or PS-TW). All relevant parameters from the modules shall be included in the monitoring plan. Monitoring shall occur for the life of the Project.

The Monitoring Plan shall include the following:

- Definition and/or revision of the Baseline Scenario[4] (as needed);
- Description of monitoring of actual carbon stock changes and GHG emissions;
- Estimation of ex-ante net carbon stock changes and GHG emissions.

[3] The San Francisco Bay Area Wetlands Ecosystem Goals Project, 2015, California State Coastal Conservancy, Oakland, CA, available at baylandsgoals.org.

[4] Baselines are only revised at the end of the crediting period.

The Monitoring Plan shall include the following sections:

- Technical description of the monitoring task;
- Data to be collected. The list of data and parameters to be collected shall be given in the GHG Project Plan;
- Description of data collection and/or sampling procedures that shall include sampling design and justification of any default values used from the literature;
- Description of biogeochemical models used for estimating carbon stock changes and GHG emissions;
- Quality control and quality assurance procedures;
- Data archiving plan.
- Organization and responsibilities of the parties involved in all the above.

1.3.5 STEP 5 Estimation of Baseline Carbon Stock Changes and GHG Emissions

Per the most recent version of the ACR Standard, the GHG Baseline is an estimation of the GHG emissions or removals that would have occurred if the Project Proponent did not implement the Project, i.e., the "business-as-usual" case. The Agricultural Baseline emissions can be estimated using validated biogeochemical models consistent with the requirements listed in the Model Module (MODEL-W/RC). Alternatively, emissions can be measured for a reference site with sufficiently similar agricultural practices, hydrologic conditions, and soils, using methods described in the Methods Module (MM-W/RC). For example, field practices that result in similar drainage conditions and depth of the unsaturated zone qualify as sufficiently similar agricultural practices relative to a Project site where field crops (e.g., corn, alfalfa) are grown. Data availability, model validation, and site-specific conditions will determine the best method for estimating Baseline GHG emissions.

The following Modules contain methods for estimating Baseline carbon stock changes and GHG emissions (see Figure 3):

- Agriculture (BL-Ag)
- Seasonal wetlands (BL-SW)
- Open water (BL-OW)

A description of and justification for the identified Baseline Scenario and the results of the estimations shall be given in the GHG Project Plan.

1.3.6 STEP 6 Estimation of Project Carbon Stock Changes and GHG Emissions

The following Modules contain guidance for estimating Project carbon stock changes and GHG emissions for Projects where wetlands and rice cultivation are planned (Figure 3):

- Managed wetlands (PS-MW)
- Tidal wetlands (PS-TW)
- Rice cultivation (PS-RC)

Methods for estimation of Project carbon stock changes and GHG emissions are described in the Methods Module (MM-W/RC).

1.3.7 STEP 7 Estimation of Total Net GHG Emissions Reductions (Baseline – Project – Leakage)

The total net GHG Project reductions are calculated as follows:

Equation 1

$$\Delta C_{ACR} = (\Delta C_{actual} - \Delta C_{BSL}) \times (1 - LK)$$

WHERE

ΔC_{ACR}	is the cumulative total net GHG emission reductions (MT CO_2e) for the Project area during the reporting period
ΔC_{BSL}	is the cumulative total of carbon stock changes and GHG emissions (MT CO_2e) for the Project area during the reporting period under the Baseline Scenario (from the selected individual Baseline, or the sum of selected Baselines if the Project includes more than one Baseline)
ΔC_{actual}	is the cumulative total of carbon stock changes and GHG emissions (MT CO_2e) for the Project area during the reporting period under the Project Scenario (from the selected Project Module)
LK	is the cumulative total of the carbon stock changes and GHG emissions due to leakage for the Project area during the reporting period

1.3.7.1 USE OF MODELS

Models can be useful tools for estimating GHG dynamics in the Baseline and Project Scenarios.

Model requirements are described in the Methods Module (MODEL-W/RC). For example, the peer-reviewed biogeochemical model known as the Peatland Ecosystem Photosynthesis, Respiration, and Methane Transport model (PEPRMT, pronounced "peppermint" and also referred to as LUE-DAMM [Oikawa 2017]) can be used for ex-ante estimation of CO_2 and CH_4 exchange from non-tidal, managed wetlands in the Sacramento-San Joaquin Delta (see Appendix C). For Baseline agricultural conditions in the Sacramento-San Joaquin Delta, the SUBCALC model (Deverel and Leighton 2010; Deverel et al. 2016) may be used to estimate Baseline CO_2 emissions (see Appendix C). The PEPRMT and SUBCALC models are not currently calibrated and validated for and cannot be applied to regions other than the Sacramento-San Joaquin Delta. Other process-based biogeochemical models may be used to estimate changes in various carbon pools and GHG sources in this methodology. Additional models are allowed if they meet the requirement specified in the Methods Module (MODEL-W/RC).

1.3.8 STEP 8 Calculation of Uncertainty

Project Proponents shall use the X-UNC module to calculate overall Project Uncertainty and estimate the uncertainty adjustment for total net GHG emissions reductions for every reporting period. If calculated total Project Uncertainty (UNC) exceeds 10% at the 90% confidence level, then ΔC_{ACR} (Equation 1) shall be adjusted for the amount exceeding the 10% as follows:

Equation 2

$$\textbf{Adjusted}\ \Delta C_{ACR} = \Delta C_{ACR} \times (1 - (UNC - 0.10))$$

WHERE

Adjusted ΔC_{ACR}	is the cumulative total net GHG emission reductions for the Project area during the reporting period adjusted to account for uncertainty (MT CO_2e)
ΔC_{ACR}	is the cumulative total net GHG emission reductions for the Project area during the reporting period (MT CO_2e)
UNC	is the total uncertainty (Project and Baseline) as derived in X-UNC (fraction)

If the calculated total Project uncertainty (UNC) in Module X-UNC is less than or equal to 10%, then no adjustment shall be made for uncertainty.

1.3.9 STEP 9 Risk Assessment

Project activities have the potential for GHG emission reductions to be unintentionally reversed, such as when a Project is subject to flooding, damage from wildlife, erosion, or intentional reversals or termination, such as landowners choosing to discontinue Project Activities before the Project minimum term has ended. Wetland GHG emission reductions are inherently at some risk of reversal or termination. Project Proponents shall mitigate reversal and termination risk per the requirements of the current ACR Standard and any applicable sector Standard.

To assess the risk of reversal or termination, the Project Proponents shall conduct a risk assessment addressing internal, external, and natural risks using the most recently approved ACR risk assessment tool. Internal risk factors include project management, financial viability, opportunity costs, and project longevity. External risk factors include factors related to land tenure, community engagement, and political forces. The primary natural termination risk to wetlands and rice projects in California is flooding due to sea level rise and/or levee failure. Levee failure and flooding in managed non-tidal wetlands and rice on subsided islands in the Sacramento-San Joaquin Delta will result in termination and reversal of cumulative GHG removals if the island is not reclaimed.

In addition to assessing risk for mitigation, each Project must also demonstrate at the initial verification that the lands within the Project boundary are projected to continue to meet the definition of wetland for the duration of minimum Project term. Project Proponents should reference existing regional risk assessments for levee failure and sea level rise.

1.3.9.1 MITIGATION OF RISK VIA THE ACR BUFFER POOL

The output of ACR's most recently approved version of the risk assessment tool is a total risk rating for the Project that equals the percentage of the Project net GHG emission reductions that must be deposited in the ACR buffer pool to mitigate the risk of reversal or termination (unless another ACR-approved risk mitigation mechanism is used in lieu of buffer contribution). The initial risk assessment and risk rating, and proposed mitigation or buffer contribution, shall be included in the GHG Project Plan. At each verification period, the risk assessment and buffer pool contributions are verified.

For Project Proponents choosing the ACR buffer pool, the Project Proponents shall contribute either a portion of the Project offsets, or an equal number of Emissions Reduction Tons (ERTs) of another type and vintage, to a buffer account held by ACR in order to replace unforeseen losses of carbon stocks. The number of ERTs contributed to the buffer pool shall be determined through the risk assessment. Buffer contributions are made with each new issuance of ERTs to a Project. In the event of a levee failure, if the Project Proponent can no longer monitor

carbon stocks and emissions following the breach and cannot reliably estimate the losses due to levee failure, then the entirety of carbon stocks in the Project boundary are assumed to be lost and required to be mitigated for via the buffer pool.

In lieu of making a buffer contribution of ERTs from either the Project or purchased from another acceptable source, Project Proponents may use an alternate ACR-approved risk mitigation mechanism, or they may propose an insurance product or other risk mitigation mechanism to ACR for approval.

1.3.10 STEP 10 Calculation of Emissions Reduction Tons (ERTs)

Equation 3

$$\mathbf{ERT} = (\mathbf{Adjusted\ \Delta C_{ACR}}) \times (\mathbf{1 - BUF})$$

WHERE

ERT	is the number of Emission Reduction Tons for the Project area during the reporting period (MT CO_2e)
Adjusted ΔC_{ACR}	is the cumulative total net GHG emission reductions adjusted for uncertainty for the Project area during the reporting period (MT CO_2e)
BUF	is the fraction of Project ERTs contributed to a buffer pool, if applicable

Per the Forest Carbon Project Standard, BUF is determined using an ACR-approved risk assessment tool. If the Project Proponent elects to make the buffer contribution in non-Project ERTs, or elects to mitigate the assessed reversal risk using an alternate risk mitigation mechanism approved by ACR, BUF shall be set to zero.

1.4 REQUIREMENTS OF PROJECT RENEWAL

The Crediting Period for all projects using this methodology is 40 years, during which the Baseline Scenario is fixed. To renew the Crediting Period, the Project Proponent must:

- Re-submit the GHG Project Plan in compliance with then-current GHG Program standards and criteria;
- Re-evaluate the Project Baseline;

- Demonstrate additionality against then-current regulations and performance standards;
- Use GHG program-approved Baseline methods, emission factors, tools, models, and methodologies in effect at the time of Crediting Period renewal;
- Undergo validation by an approved validation/verification body.

1.5 PARAMETER TABLES

PARAMETERS ORIGINATING IN OTHER MODULES

DATA/ PARAMETER	ΔC_{BSL}
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 1
DESCRIPTION	Cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period for the Baseline Scenarios where there are agricultural activities, open water, or seasonal wetlands in place immediately prior to the Project commencement date
MODULE PARAMETER ORIGINATES IN	BL-Ag, BL-SW, or BL-OW

DATA/ PARAMETER	ΔC_{actual}
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 1
DESCRIPTION	Cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period for the Project Scenario where the Project Activity can include hydrologic management, infrastructure modification, and plantings or natural plant recruitment
MODULE PARAMETER ORIGINATES IN	PS-MW, PS-TW, or PS-RC

DATA/ PARAMETER	LK
DATA UNIT	Fraction (dimensionless)
USED IN EQUATION	Equation 1
DESCRIPTION	Cumulative total of the carbon stock changes and GHG emissions due to leakage for the Project area during the reporting period
MODULE PARAMETER ORIGINATES IN	Leakage analysis

DATA/ PARAMETER	BUF
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 3
DESCRIPTION	Part of ΔC_{ACR} for contribution to a buffer pool in case of Project reversal or termination
MODULE PARAMETER ORIGINATES IN	Risk tool

DATA/ PARAMETER	UNC
DATA UNIT	Fraction (dimensionless)
USED IN EQUATION	Equation 2
DESCRIPTION	Total uncertainty (Project and Baseline)
MODULE PARAMETER ORIGINATES IN	X-UNC

2 BASELINE QUANTIFICATION MODULES

PREFACE

The objective of this methodology is to describe quantification procedures for the reduction of greenhouse gas (GHG) emissions through conversion of land to wetlands and rice cultivation. This methodology achieves GHG emissions reductions by 1) halting or greatly reducing soil organic carbon oxidation; and 2) increasing soil organic storage by restoring wetlands (tidal and non-tidal) and cultivating rice.

The methodology has been written in a modular format; Project Proponents can choose the applicable Modules for their specific Project and site. First, the Framework Module provides background and an overarching description of the Methodology requirements and Modules. All Projects must meet the requirements outlined in the Methodology Framework Module (MF-W/RC). Next, the remaining Modules provide guidance for Baseline and Project Scenario quantification, methods, modeling, calculation of uncertainty, and other quantification tools. From these supporting Modules, Project Proponents will select the relevant components for a Project.

The Baseline Quantification Modules in this chapter describe conditions, processes and quantification procedures of GHGs related to three potential baseline scenarios: (2.1) Baseline condition is agriculture (BL-Ag); (2.2) Baseline condition is seasonal wetland (BL-SW); and (2.3) Baseline condition is open water (BL-OW).

Project Proponents must identify the most plausible and credible Baseline Scenario describing what would have occurred in absence of the Project activities.

2.1 (BL-AG) BASELINE CONDITION IS AGRICULTURE

2.1.1 Scope, Background, Applicability and Parameters

2.1.1.1 SCOPE AND BACKGROUND

This Module provides guidance for estimating carbon stock changes and GHG emissions for agricultural lands in the Sacramento-San Joaquin Delta and coastal California in the Baseline case where the Project activity will be managed wetland construction, tidal wetlands, or rice cultivation. The Module provides specific guidance for identifying the Baseline Scenario, defining the Project GHG boundary, stratification, and estimating carbon stock changes and GHG emissions.

2.1.1.2 APPLICABILITY

The Module is applicable for estimating carbon stock changes and GHG emissions for Baseline Project areas planned for managed wetland construction and/or rice cultivation. Project activities will occur due to some combination of hydrologic management changes and infrastructural modification with assisted natural regeneration or seeding. Infrastructural modification includes drainage modification and earth moving. Project activities shall meet the applicability conditions in the methodology framework listed under wetland construction and rice cultivation. The following conditions must be met to apply this Module:

- The Project area must be on agricultural lands where crops are grown and/or animals are grazed;
- Typical crops include but are not limited to field crops such as corn or alfalfa and vegetable crops such as tomatoes, where a drained root zone is required;
- Pasture can also be included as Baseline Scenario and animal GHG emissions may be included as Baseline GHG emissions, if a leakage analysis determines animal GHG emissions will not be moved outside the Project boundaries because of the Project;
- The Project area must have been used as agricultural land at least 6 out of the 10 years prior to the Project start date.

2.1.1.3 PARAMETERS

This Module provides procedures to determine the following parameter:

PARAMETER	SI UNITS	DESCRIPTION
$\Delta C_{BSL\ Ag}$	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period for the Baseline agricultural Scenario when the Project Activity will include managed wetlands, tidal wetlands, or rice
The notation for this parameter in the Framework Module is expressed in its generic form as ΔC_{BSL} in Equation 1		

2.1.2 Procedure

2.1.2.1 IDENTIFICATION OF THE BASELINE SCENARIO

Project Proponents must identify the most plausible and credible Baseline Scenario describing what would have occurred in absence of the Project activities. Under this Module, the Baseline Scenario must be limited to agricultural land uses. The geographical coordinates of the boundaries of each Project area must be unambiguously defined and provided to the Validation/Verification Body (VVB) in shapefile format.

2.1.2.2 ESTABLISHMENT AND DOCUMENTATION OF THE GHG BOUNDARY

The Project GHG boundary describes the carbon pools and GHG emissions sources that will be included or excluded from GHG accounting, as defined in the Methodology Framework Module (MF-W/RC). It shall be demonstrated that each discrete parcel of land to be included in the Project boundary is eligible as an ACR Project Activity. For the Baseline case, the primary carbon pools include the soil organic carbon pool and emissions due to oxidation of soil organic matter and fertilizer use, as shown in Table 14.

Table 14: Baseline Emissions Sources Included in the Project Boundary

Nitrous oxide (N_2O) and methane (CH_4) are considered optional (see Methodology Framework Module (MF-W/RC))

SOURCE	GAS
Emissions due to fertilizer application and manure emissions	N_2O

SOURCE	GAS
Emissions due to oxidation and anaerobic decomposition of soil organic matter and enteric fermentation from livestock	N_2O, CO_2, CH_4
Emissions resulting from fossil fuel combustion	CO_2

2.1.2.3 BASELINE STRATIFICATION

For estimation of Baseline net GHG removals or emissions, strata shall be defined based on parameters that affect GHG removals or emissions and/or are factors that influence measurement of changes in biomass stocks. These may include but are not limited to the factors or practices in Table 15.

Table 15: Factors and Practices that Can Be Used for Stratification and Their Effects on GHG Emissions and Removals

STRATIFICATION FACTOR OR PRACTICE	DESCRIPTION	POTENTIAL GHG EFFECT
Vegetation	Crop species	Affects CO_2 sequestration
Soil classification and chemical composition	Soil organic matter, pH, carbon-to-nitrogen ratio, and texture.	Soil organic matter content is a key determinant of Baseline GHG emissions on organic soils. The other factors affect GHG emissions and removal.
Hydrology	Depth of water and topography (drain ditches, difference in elevation)	Depth of water affects vegetation, thus CO_2 sequestration, and GHG emissions.
Agricultural land use	Crop type (hay or grain crop, pasture)	Affects Baseline GHG emissions and CO_2 sequestration

STRATIFICATION FACTOR OR PRACTICE	DESCRIPTION	POTENTIAL GHG EFFECT
Agriculture practices	Harvest, fertilization, etc.	Affects carbon stored in the ecosystem and GHG emissions

2.1.2.4 QUANTIFY BASELINE CARBON STOCKS AND GHG EMISSIONS

The Baseline Scenario consists of the most likely projected carbon stock changes and GHG emission in the absence of Project implementation for the life of the Project. The Baseline Scenario is fixed for the life of the Project. The Baseline net GHG emissions shall be estimated using the methodology described in this section and in the Methods Module (MM-W/RC). The Methods Module MODEL-W/RC lists requirements for using biogeochemical models, and for using data from sites with sufficiently similar agricultural practices, hydrologic conditions, and soils. For ex-ante calculation of Baseline net GHG emissions, the Project Proponents shall provide estimates of the site-specific values for the appropriate parameters used in the calculations and/or model estimates. Project Proponents shall retain a conservative approach in making these ex-ante estimates.

The cumulative total carbon stock change and GHG emissions for the agricultural Baseline Scenario is:

Equation 4

$$\Delta C_{BSL_Ag} = \Delta Cs_{BSL_Ag} + fGHG_{BSL_Ag} + fEFF_{BSL_Ag}$$

WHERE

ΔC_{BSL_Ag}	is the cumulative total of carbon stock changes and GHG emissions for the agricultural Baseline Scenario for the Project area during the reporting period
ΔCs_{BSL_Ag}	is the cumulative carbon stock change for the Project area during the reporting period
$fGHG_{BSL_Ag}$	is the cumulative total biogenic GHG emissions for the Project area during the reporting period
$fEFF_{BSL_Ag}$	is the emissions of fossil fuels for the Project area during the reporting period

Comment	The terms will be added in case GHG exchanges are going in the same direction (from biosphere to atmosphere or vice versa) and subtracted when in opposite directions

When the soil carbon pool includes all components of the ecosystem carbon dynamic, the above equation is reduced to the soil carbon pool change and the fossil fuel emissions (see section 1.3.2.3). The decrease in the soil carbon pool is measured using methods described in the Methods Module (MM-W/RC). For calculation of fossil fuel combustion, see the Methods Module (E-FFC). Double counting shall be avoided. For example, if annual fluxes of CO_2, CH_4, and N_2O are measured in the field or estimated using models, no additional annual soil carbon stock changes should be considered.

2.1.3 Parameter Tables

PARAMETERS ORIGINATING IN OTHER MODULES

DATA/ PARAMETER	ΔC_{BSL_Ag}
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 4
DESCRIPTION	Cumulative C stock changes for the Project area during the reporting period for the Baseline Scenario
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Baseline C stock changes shall be estimated using techniques described in the Methods Module MM-W/RC or MODEL-W/RC

DATA/ PARAMETER	$fGHG_{BSL_Ag}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 4

DESCRIPTION	Cumulative net total of biogenic GHG emissions for the Project area during the reporting period for the Baseline Scenario
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Baseline GHG fluxes shall be estimated using techniques described in the Methods Module MM-W/RC or MODEL-W/RC

DATA/ PARAMETER	$fEFF_{BSL_Ag}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 4
DESCRIPTION	Emission of fossil fuels for the Project area during the reporting period in the Baseline Scenario
MODULE PARAMETER ORIGINATES IN	E-FFC
COMMENT	These GHG emissions shall be estimated using techniques described in the Module E-FFC and only included if significant

2.2 (BL-SW) BASELINE CONDITION IS SEASONAL WETLANDS

2.2.1 Scope, Background, Applicability, and Parameters

2.2.1.1 SCOPE AND BACKGROUND

This Module provides guidance for estimating carbon stock changes and GHG emissions for seasonal wetlands in the Baseline case where the Project activity will be wetland construction or rice cultivation. Seasonal wetlands can be hydrologically managed for hunting or are areas that are currently too wet to farm due to excessive seepage. The Module provides specific

guidance for identifying the Baseline Scenario, defining the Project GHG boundary, stratification, and estimating carbon stock changes and GHG emissions.

2.2.1.2 APPLICABILITY

The Module is applicable for estimating Baseline GHG emissions and carbon stock changes for Project areas planned for wetland construction or rice cultivation. These land use changes will occur due to some combination of hydrologic management changes and infrastructural modification with assisted natural regeneration or seeding. Infrastructural modification includes drainage modification and earth-moving. The following conditions must be met to apply this Module:

- The Project area must be on lands where there are seasonal wetlands;
- This Module is always mandatory when the Project activity will include wetland construction and restoration and rice cultivation on lands where there are seasonal wetlands;
- Seasonal wetlands include areas in the Delta and San Francisco Bay Estuary that may be used for attracting and breeding waterfowl for hunting, such as duck clubs (Table 16).

Table 16: Examples of Eligible Seasonal Wetlands

SEASONAL WETLAND TYPE	EXAMPLES	COMMENTS
Managed seasonal wetlands	Suisun Marsh seasonal wetlands used for attracting and breeding waterfowl for hunting. There are also seasonal wetlands used for hunting in the Delta.	Most of the land within Suisun Marsh (85%) consists of diked wetlands that are flooded part of the year and drained from mid-July through mid-September (Chappell 2006; Okamoto and Wong, 2011). These areas have subsided since the 1950s, thus indicating CO_2 loss (HydroFocus Inc. 2007).
Unmanaged seasonal wetlands	Many areas of the central Delta where elevations are less than 2 m below sea level have become too wet to farm and are now seasonal wetlands (Deverel et al. 2015).	These areas likely continue to subside and emit carbon dioxide. Miller et al. (2000) and Deverel et al. (1998) demonstrated the net loss of carbon from similar systems in the Delta.

2.2.1.3 PARAMETERS

This Module provides procedures to determine the following parameter:

PARAMETER	SI UNIT	DESCRIPTION
DC_{BSL_SW}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period for the seasonal wetlands Baseline Scenario

The notation for this parameter in the Framework Module is expressed in its generic form as ΔC_{BSL} in Equation 1

2.2.2 Procedure

2.2.2.1 IDENTIFICATION OF THE BASELINE ACTIVITIES

Project Proponents must identify the most plausible and credible Baseline Scenario that would have occurred in absence of the Project Activities. Therefore, the Project Proponent needs to demonstrate that seasonal wetlands are the most likely scenario. The geographical coordinates of the boundaries of each Project area must be unambiguously defined and provided to the Validation/Verification Body (VVB) in shapefile format.

2.2.2.2 ESTABLISHMENT AND DOCUMENTATION OF THE GHG BOUNDARY

The Project GHG boundary describes the carbon pools that will be included or excluded from GHG accounting. It shall be demonstrated that each discrete parcel of land to be included in the boundary is eligible for wetland or rice Project activity. For the Baseline case, the GHG boundary includes primarily emissions due to oxidation and loss of soil organic carbon. Hydrologic management and infrastructural modification practices in seasonal wetlands may result in GHG emissions that shall be accounted for. These include emissions associated with earth-moving and vegetation control if determined to be significant. Animal-source GHG emissions can be accounted for the seasonal wetlands Baseline conditions, if leakage analysis shows the animals will not simply move outside the Project area. Exclusion of carbon pools and emission sources is allowed subject to considerations of conservativeness and significance testing. Pools or sources can be neglected (i.e., counted as zero) if application of the tool T-SIG indicates that the source is insignificant, i.e., the source represents less than 3% of the ex-ante calculation of GHG emission reductions. If monitoring of Baseline and Project emissions deter-

mines that an emission source(s) initially included in the GHG assessment boundary is insignificant using the tool T-SIG, monitoring may cease. The Baseline Scenario consists of the most likely emissions and removals in the absence of Project implementation as shown in Table 17.

Table 17: Baseline Emissions Sources Included in the Project Boundary

Nitrous oxide and methane are considered optional (see Methodology Framework Module (MF-W/RC)).

SOURCE	GAS
Soil emissions due to fertilizer application	N_2O
Soil emissions due to oxidation of organic soils	N_2O, CO_2, CH_4
Emissions resulting from fossil fuel combustion	CO_2

2.2.2.3 BASELINE STRATIFICATION

For estimation of Baseline net GHG removals or emissions, or estimation of Project net GHG emission reductions, strata shall be defined based on parameters that affect GHG removals or emissions and/or are factors that influence the measurement of changes in biomass stocks. Potential stratification factors for seasonal wetlands as a Baseline Scenario are listed in Table 18.

Table 18: Factors and Practices that Can Be Used for Stratification and Their Effects on GHG Emissions and Removals

STRATIFICATION FACTOR OR PRACTICE	DESCRIPTION	POTENTIAL GHG EFFECT
Wetland management practices	Depth of water	Affects vegetation, CO_2 sequestration, and CH_4 emissions
Wetland management practices	Flow through or limited or zero outflow	Affects CH_4 emissions
Wetland vegetation	Variation in species	Affects CO_2 sequestration
Wetland vegetation	Vegetation establishment (seedlings, seeds, or natural recruitment)	Affects time required for vegetative cover, CO_2 sequestration and CH_4 emissions.
Wetland age	Years since wetland creation	Affects CO_2 sequestration
Open water areas	Areas without emergent aquatic vegetation	Minimal CO_2 sequestration GHG emissions
Wetland spatial variability	Water circulation	Affects CO_2 sequestration and GHG emissions
Soil classification and chemical composition	Soil organic matter, pH, carbon-to-nitrogen ratio, salinity, and texture.	Soil organic matter is a key determinant of Baseline GHG emissions. The other factors affect GHG emissions and removal.
Soil hydrology	Depth to groundwater, oxidation-reduction conditions	Depth to groundwater is an important determinant of Baseline GHG emissions on organic soils

For actual Baseline emissions, the stratification for ex-ante estimations shall be based on the Project Monitoring Plan.

2.2.2.4 QUANTIFY BASELINE CARBON STOCKS AND GHG EMISSIONS

The Baseline Scenario consists of the most likely projected emissions and removals in the absence of Project implementation for the life of the Project. The Baseline Scenario is fixed for the life of the Project. The Baseline net GHG emissions shall be estimated using the methodology described in this section and the Measurement Module (MM-W/RC), or using calibrated and validated biogeochemical models as described in the Model Module (MODEL-W/RC). For ex-ante calculation of Baseline net GHG emissions, the Project Proponents shall provide estimates of the site-specific values for the appropriate parameters used in the calculations and/or model estimates. Project Proponents shall retain a conservative approach in making these ex-ante estimates.

The cumulative total of carbon stock change and GHG emissions for the Baseline seasonal wetlands Scenario is

Equation 5

$$\Delta C_{BSL_SW} = \Delta Cs_{BSL_SW} + fGHG_{BSL_SW} + fEFF_{BSL_SW}$$

WHERE

ΔC_{BSL_SW}	is the cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period for the seasonal wetlands Baseline Scenario
ΔCs_{BSL_SW}	is the cumulative carbon stock change for the Project area during the reporting period
$fGHG_{BSL_SW}$	is the cumulative net biogenic emissions due to oxidation of organic matter of the Project area during the reporting period
$fEFF_{BSL_SW}$	is the emissions of fossil fuels per Project area during the reporting period
Comment	The terms will be added in case GHG exchanges are going in the same direction (from biosphere to atmosphere or vice versa) and subtracted when in opposite directions

Double-counting should be avoided (see section 1.3.2.3).

2.2.3 Parameter Tables

PARAMETERS ORIGINATING IN OTHER MODULES

DATA/ PARAMETER	ΔCs_{BSL_SW}
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 5
DESCRIPTION	Cumulative net carbon stock changes for the Project area during the reporting period for the seasonal wetlands Baseline Scenario
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Estimated using methods described in Module MM-W/RC or MODEL W/RC

DATA/ PARAMETER	$fGHG_{BSL_SW}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 5
DESCRIPTION	Cumulative net biogenic emissions due to oxidation of organic matter of the Project area during the reporting period
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Estimated using methods described in Module MM-W/RC or MODEL-W/RC

DATA/ PARAMETER	$fEFF_{BSL_SW}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 5
DESCRIPTION	Emission of fossil fuels for the Project area during the reporting period in the Baseline Scenario
MODULE PARAMETER ORIGINATES IN	E-FFC
COMMENT	Estimated using methods described in the Methods Module E-FFC

2.3 (BL-OW) BASELINE CONDITION IS OPEN WATER

2.3.1 Scope, Background, Applicability, and Parameters

2.3.1.1 SCOPE AND BACKGROUND

This Module provides guidance for estimating carbon stock changes and GHG emissions for open water areas in the Baseline case where the Project Activity will be tidal wetland restoration. For example, candidate open water areas are primarily former salt ponds located in the San Francisco Bay Estuary. These areas can be potentially converted to tidal wetlands. The Module provides specific guidance for identifying the Baseline Scenario, defining the Project GHG boundary, stratification, and estimating carbon stock changes and GHG emissions.

2.3.1.2 APPLICABILITY

The Module is applicable for estimating Baseline carbon stock changes and GHG emissions for Project areas planned for tidal wetland construction and restoration. This Module is mandatory when the Project activity includes hydrologic management and infrastructural modification of areas of open water for tidal wetlands including tidal marshes and eelgrass meadows. These land use changes will occur due to some combination of hydrologic management

changes and infrastructural modification with assisted natural regeneration and seeding. Infrastructural modification includes earth-moving, berm and levee construction, drainage modification, and application of dredge materials.

The following condition must be met to apply this Module:

- Under this Module, the Baseline Scenario must be limited to open water.

2.3.1.3 PARAMETERS

This Module provides procedures to determine the following parameter:

PARAMETER	SI UNIT	DESCRIPTION
ΔC_{BSL_OW}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period for the open water Baseline Scenario
The notation for this parameter in the Methodology Framework Module is expressed in its generic form as ΔC_{BSL} in Equation 1		

2.3.2 Procedure

2.3.2.1 IDENTIFICATION OF THE BASELINE ACTIVITIES

Project Proponents must identify the most plausible and credible Baseline Scenario describing what would have occurred in absence of the Project Activities. Under this Module, the Baseline Scenario must be limited to open water. The geographical coordinates of the boundaries of each Project area must be unambiguously defined and provided to the Validation/Verification Body (VVB) in shapefile format.

2.3.2.2 ESTABLISHMENT AND DOCUMENTATION OF THE GHG BOUNDARY

The Project GHG boundary describes the GHG sources and sinks that will be included or excluded from GHG accounting as defined in the Methodology Framework Module (MF-W/RC). It shall be demonstrated that each discrete parcel of land to be included in the boundary is eligible for Project activity. For the open-water Baseline case, emissions will occur due to fossil fuel combustion during dredging operations, infrastructural modification, earth-moving, and construction. These emissions must be accounted for if they are determined to be significant. CH_4

ebullition may also occur. Emissions shall be estimated based on site/Project-specific data, an acceptable proxy, reference sample plots or field monitoring of similar sites, peer-reviewed literature, approved local parameters, and model estimates. Baseline emissions include GHG emissions within the Project boundary prior to site preparation, or the most likely emissions in the absence of the Project activity (Table 19).

Table 19: Baseline Emissions Sources Included in the Project Boundary

Nitrous oxide and methane are considered optional (see Methodology Framework Module (MF-W/RC)).

SOURCE	GAS
Emissions due to oxidation of organic matter	CO_2, N_2O, CH_4
Emissions resulting from fossil fuel combustion	CO_2

Allochthonous carbon may enter the open water area from an outside source and may contribute to carbon accumulation at the site. However, if it represents carbon assimilated by other sinks, the wetland Project area does not contribute to its removal from the atmosphere. For this reason, after it is quantified as described in the Measurement Module (MM-W/RC, Equation 12), it should be deducted from the carbon balance of the Project area. For purposes of this methodology, carbon accumulation from outside sources may be excluded in determination of Baseline GHG emissions or removals if not significant as per guidance in the Methods Module (MM-W/RC and tool T-SIG). Allochthonous carbon accumulation in the Baseline may be conservatively set to zero, as its exclusion from the balance between GHG losses and gains would underestimate net GHG reductions (i.e., ERTs).

The Project Proponents using emission values from the literature or non-site data must make conservative estimates to determine the Baseline GHG emissions. Exclusion of carbon pools and emission sources is allowed subject to considerations of conservativeness and significance testing. This may be accomplished by using peer-reviewed literature, reference sample plots or field monitoring of similar sites, approved local or national parameters, the most recent default emission factors provided by the IPCC, government reports, and models. Pools or sources may be excluded if the exclusion tends to underestimate net Project GHG emission reductions (i.e. ERTs). Additional guidance is provided in the Methods Module (MM-W/RC).

Pools or sources can be neglected (i.e., counted as zero) if application of the tool T-SIG (Methods Module section 4.6) indicates that the source is insignificant, i.e., the source represents less than 3% of the ex-ante calculation of GHG emission reductions. If monitoring of Baseline and Project emissions indicate that an emission source(s) initially included in the GHG assessment boundary is insignificant using the tool T-SIG, monitoring may cease.

Attention must be used when estimating CH_4 emissions in open water in presence of salinity. Salinity can reduce CH_4 emissions. Where a default emission factor approach is used based on salinity, the average or low value of salinity shall be measured in shallow pore water or soils within 30 cm of land surface using acceptable technology or analytical determination of total dissolved solids. Sulfate concentrations shall also be determined when salinity is measured using standard analytical methods at a certified laboratory. The salinity average shall be calculated from measurements during periods of peak CH_4 emissions. When the frequency of measurements is less than monthly for 1 year, the minimum salinity value shall be used. For calculation of CH_4 fluxes in presence of salinity, refer to section 3.2.2.4.

2.3.2.3 BASELINE STRATIFICATION

For estimation of Baseline net GHG emissions, strata shall be defined based on parameters that affect GHG emissions. These may include the following:

- Depth of open water
- Water quality (e.g., salinity, nutrient inputs, distance from source, etc.)
- Soil organic matter content
- Vegetation
- Sediment chemical and physical properties (e.g., redox conditions, temperature)

These are the primary factors that affect GHG emissions. If natural or anthropogenic impacts (e.g., levee breaks and flooding) or other factors (e.g., altered hydrology or water management) add variability in the vegetation of the Project area, then the stratification shall be revised accordingly.

2.3.2.4 QUANTIFY BASELINE CARBON STOCKS AND GHG EMISSIONS

The Baseline Scenario consists of the most likely projected emissions and removals in the absence of Project implementation for the life of the Project. The Baseline Scenario is fixed for the life of the Project. The Baseline net GHG emissions shall be estimated using the methodology described in this section and the Methods Module MM-W/RC or using biogeochemical models responding to requirements listed in the Methods Module MODEL-W/RC. When applying these methods for the calculation of Baseline net GHG removals or emissions, the Project Proponents shall provide estimates of the site-specific values for the appropriate parameters. The Project Proponents shall retain a conservative approach in making these estimates.

Baseline carbon stock changes and GHG emissions for the Baseline reporting period, ΔC_{BSL_OW} shall be estimated using the following equation for the Baseline reporting period for the Project area.

Equation 6

$$\Delta C_{BSL_OW} = \Delta Cs_{BSL_OW} \mp fGHG_{BSL_OW} + fEFF_{BSL_OW}$$

WHERE

ΔC_{BSL_OW}	is the cumulative carbon stock change and GHG emissions for the Project area during the reporting period
ΔCs_{BSL_OW}	is the cumulative carbon stock change for the Project area during the reporting period
$fGHG_{BSL_OW}$	is the net emissions of N_2O, CO_2, and CH_4 due to the decomposition of organic matter for the Project area during the reporting period
$fEFF_{BSL_OW}$	is the total emissions as a result of fossil fuel combustion within the Project boundary during the reporting period
Comment	The terms will be added in case GHG exchanges are going in the same direction (from biosphere to atmosphere or vice versa) and subtracted when in opposite directions

If deemed significant, the Baseline GHG emissions due to organic matter decomposition from the Project area may be estimated from direct measurement of gaseous fluxes prior to Project activity as described in the Methods Module (MM-W/RC) or determined based on an acceptable proxy data, from peer-reviewed literature, or models. Estimation of emissions from fossil fuel combustion shall be estimated as described in the Emissions Module (E-FFC).

2.3.3 Parameter Tables

PARAMETERS ORIGINATING IN OTHER MODULES

DATA/ PARAMETER	ΔCs_{BSL_OW}
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 6

DESCRIPTION	Cumulative net carbon stock changes for the Project area during the reporting period for the open water Baseline Scenario
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Estimated using measurements (MM-W/RC) or biogeochemical models (Model-W/RC)

DATA/ PARAMETER	$fGHG_{BSL_OW}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 6
DESCRIPTION	Net GHG emissions (CO_2, CH_4, N_2O) for the Project area during the reporting period due to the decomposition of organic matter
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Estimated using measurements (MM-W/RC) or biogeochemical models (MODEL-W/RC)

DATA/ PARAMETER	$fEFF_{BSL_OW}$
DATA UNIT	MT $CO_2e\ yr^{-1}$
USED IN EQUATION	Equation 6
DESCRIPTION	GHG emissions for the Project area over the reporting period as a result of fossil fuel combustion for the Baseline Scenario

MODULE PARAMETER ORIGINATES IN	E-FFC
COMMENT	Estimated using methods described in Module E-FFC

3 PROJECT MODULES

PREFACE

The objective of this methodology is to describe quantification procedures for the reduction of greenhouse gas (GHG) emissions through conversion of land to wetlands and rice cultivation. This methodology achieves GHG emissions reductions by 1) halting or greatly reducing soil organic carbon oxidation; and 2) increasing soil organic storage by restoring wetlands (tidal and non-tidal) and cultivating rice.

The methodology has been written in a modular format; Project Proponents can choose the applicable Modules for their specific Project and site. First, the Framework Module provides background and an overarching description of the Methodology requirements and Modules. All Projects must meet the requirements outlined in the Methodology Framework Module (MF-W/RC). Next, the remaining Modules provide guidance for Baseline and Project Scenario quantification, methods, modeling, calculation of uncertainty, and other quantification tools. From these supporting Modules, Project Proponents will select the relevant components for a Project.

The Project Quantification Modules in this chapter describe conditions, processes and quantification procedures of GHGs related to three potential project scenarios: (3.1) Project condition is managed wetlands (PS-MW); (3.2) Project condition is tidal wetland (PS-TW); and (3.3) Project condition is rice cultivation (PS-RC).

The methodology is applicable on subsided and/or drained agricultural lands with high organic soil content in California, the majority of which are located in the Sacramento-San Joaquin Delta (“the Delta”) and San Francisco Bay regions.

If, within the Project area, drainage and/or other unplanned and prohibited activities (e.g., flooding) occur, the situation shall be revised. Subsequent documentation shall quantify the effects on GHG emissions, emissions reductions, or GHG sink enhancements.

3.1 (PS-MW) PROJECT CONDITION IS MANAGED WETLANDS

3.1.1 Scope, Background, Applicability, and Parameters

3.1.1.1 SCOPE AND BACKGROUND

This Module provides guidance for estimating ex-ante and ex-post carbon stock changes and GHG emissions related to managed non-tidal wetlands when the Project activity includes hydrologic management, infrastructural modification, and plantings or natural plant regeneration. Hydrologic management includes alteration of water management practices and water delivery and drainage structures such that drained conditions prevalent for agricultural are eliminated and the land is flooded for wetlands. The Module provides specific guidance for determining applicability, monitoring, Project implementation, stratification, and estimating carbon stock changes and GHG emissions.

3.1.1.2 APPLICABILITY

This Module is always mandatory when the Project Activity includes hydrologic management, infrastructural modification, and plantings or natural plant regeneration for construction of managed non-tidal wetlands. Infrastructural modification includes drainage modification and earthmoving. The Baseline Scenario for this Project activity is limited to agriculture and seasonal wetlands.

The following conditions must be met to apply this Module:

- The Project area must be on agricultural lands where crops are grown and/or animals are grazed or seasonal wetlands;
- Baseline emissions can also include fertilization and enteric livestock fermentation. Animal-source GHG emissions can be included if a leakage assessment shows animals are not transferred outside the Project area;
- The Project Activity is implementation of managed non-tidal wetlands.[5]

[5] Managed wetlands can include paludiculture in which the wetland plants are harvested periodically for economic benefit.

3.1.1.3 PARAMETERS

This Module produces the following parameter.

PARAMETER	SI UNIT	DESCRIPTION
ΔC_{actual_MW}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period under the managed wetlands Project

The notation for this parameter in the Methodology Framework Module is expressed in its generic form as ΔC_{actual} in Equation 1

3.1.2 Procedure

3.1.2.1 ESTABLISHMENT AND DOCUMENTATION OF THE GHG BOUNDARY

Information to delineate the Project boundary may include the following:

- USGS topographic map or property parcel map where the Project boundary is recorded for all areas of land. Provide the name of the Project area (e.g., compartment number, allotment number);
- Local name and a unique ID for each discrete parcel of land;
- Aerial map (e.g., orthorectified aerial photography or georeferenced remote sensing images);
- Geographic coordinates for the Project boundary, total land area, and land holder and user rights.

A Geographic Information System shapefile that specifies Project boundary locations and related information is required.

3.1.2.1.1 Consideration of Sea Level Rise

If relevant in the determination of geographical Project boundaries and strata, Project Proponents shall estimate relative sea level rise and assess its effects over the Crediting period. For both the Baseline and Project Scenarios, the Project Proponent shall estimate relative sea level rise within the Project area based on peer-reviewed literature and/or federal, state, and re-

gional planning documents applicable to the region. The assessment of potential wetland migration, inundation, and erosion with projected sea level rise must account for topographical slope, management, sediment supply, and tidal range. Project Proponents shall be conservative, i.e., use the upper range of estimated sea level rise values for the 40-year Crediting period.

3.1.2.1.2 Sources and Sinks

Managed non-tidal wetlands sequester CO_2 as biomass. CH_4 is the primary emission from managed non-tidal wetlands due to decomposition of organic matter. There are also fossil fuel emissions resultant from wetland construction activities. N_2O emissions are generally low and even negative in un-enriched managed wetlands. Under permanently flooded soil conditions, N_2O is consumed during denitrification and converted to N_2 (Butterbach-Bahl et al. 2013).

3.1.2.2 PROJECT STRATIFICATION

In the GHG Project Plan, Project Proponents shall present an ex-ante stratification of the Project area or justify the absence of stratification. Stratification for ex-ante estimations shall be described in the Project Management Plan. Table 20 provides typical factors and practices that can be used for stratification.

Strata shall be delineated using spatial data (e.g., maps, GIS, classified imagery). Strata must be spatially discrete and stratum areas must be known. Areas of individual strata must sum to the total Project Area.

Table 20: Factors and Practices that Can Be Used for Stratification and Their Effects on GHG Emissions and Removals

STRATIFICATION FACTOR OR PRACTICE	DESCRIPTION	POTENTIAL GHG EFFECT
Wetland management practices and infrastructural modification variations	Depth of water and land surface elevation, excavated and filled areas	Affects CO_2 sequestration and CH_4 emissions and vegetation Infrastructural modifications affect fossil fuel emissions
Wetland management practices	For example, flow through or limited or zero outflow	Affects CH_4 emissions
Wetland vegetation	Plant species	Affects CO_2 sequestration

STRATIFICATION FACTOR OR PRACTICE	DESCRIPTION	POTENTIAL GHG EFFECT
Wetland vegetation	Vegetation establishment (seedlings, seed, natural recruitment)	Affects time required for vegetative cover, thus CO_2 sequestration and CH_4 emissions
Wetland age	Years since wetland creation	Affects CO_2 sequestration
Open water areas	Areas without emergent aquatic vegetation	Minimal CO_2 sequestration, GHG emissions
Wetland spatial variability	Water circulation	Affects CO_2 sequestration and GHG emissions
Soil classification and chemical composition	Soil organic matter, pH, carbon-to-nitrogen ratio, salinity, and texture	Soil organic matter is key determinant of Baseline GHG emissions. The other factors affect GHG emissions and removal
Soil hydrology	Depth to groundwater, oxidation-reduction conditions	Depth to groundwater is an important determinant of GHG emissions

3.1.2.3 MONITORING PROJECT IMPLEMENTATION

As described in the Methodology Framework Module (MF-W/RC), Project Proponents shall include a single Monitoring Plan in the GHG Project Plan that includes a description of Baseline and Project monitoring and estimation of carbon stock changes and GHG emissions. Information shall be provided, to document that:

- The geographic coordinates of the Project boundary (and any stratification inside the boundary) are established, recorded, and archived;
- Standard operating procedures (SOPs) and quality control/quality assurance (QA/QC) procedures for field data collection and data management are applied;
- Use or adaptation of relevant practices already applied in managed wetland monitoring, or available from published relevant materials, are implemented;
- The Monitoring Plan, together with a record of implemented practices and monitoring during the Project duration, shall be available for validation and verification. Information on sampling methodologies and associated uncertainty for managed wetlands can be

obtained from a review of the available literature for managed wetlands in the Sacramento-San Joaquin Delta. For example, Miller et al. (2008) provided data on spatial variability of sedimentation erosion table and coring measurements that can help guide plot and instrumentation placement.

3.1.2.4 QUANTIFY PROJECT CARBON STOCK CHANGES AND GHG EMISSIONS

Carbon stock changes and GHG emissions shall be estimated using the methodology described in the Methods Module. The methods listed in the Measurement Module (MM-W/RC) may be used alone or in tandem. Carbon stock changes and GHG emissions can be estimated using appropriate peer-reviewed proxy measurement data for similar situations, in which case the environmental setting for the estimates shall be detailed. Also, there shall be an in-depth demonstration of conservativeness and applicability. Biogeochemical models that meet requirements listed in the Model Module (MODEL-W/RC) can be used for estimating carbon stock changes and GHG emissions. For example, the peer-reviewed biogeochemical model, Peatland Ecosystem Photosynthesis, Respiration, and Methane Transport model (PEPRMT, see Appendix C), can be used for estimation of CO_2 and CH_4 exchange from non-tidal, managed wetlands in the Sacramento-San Joaquin Delta.

Parameter estimates shall be based on measured data or published data that can be demonstrated as applicable. If different values for a parameter used in models or calculations are equally plausible, a value that does not lead to over-estimation of net GHG emission reductions must be selected and its use shall be documented. If Project activities include moving sediments, fossil fuel combustion emissions must be quantified during Project activities using methods described in the Method Module E-FFC if determined to be significant, using the tool T-SIG. An ex-ante estimate of fuel consumption shall be made based on projected fuel usage.

Measurement methods to quantify C stocks changes and GHG emissions are described in the Methods Module (MM-W/R). Carbon pools include biomass and soil organic carbon stock changes. Acceptable methods include eddy covariance and soil coring.

A 5-year interval is considered adequate for the determination of changes in soil carbon stocks in managed wetlands. Specifically, soil coring for measurements of soil carbon stock changes can be conducted every 5 years after Project inception and placement of feldspar markers. If eddy covariance measurements are used to estimate carbon stock changes, continual monitoring shall occur from Project inception unless another method is selected in combination with eddy covariance (such as a biogeochemical model). Project Proponents shall demonstrate that spatial and temporal heterogeneity is adequately represented in the calculation of the emission reductions. Peer-reviewed biogeochemical models calibrated and validated for Project conditions can be used to simulate Project carbon stock changes and GHG emissions at 5-year intervals. See the Model Module (MODEL-W/RC) for model-use requirements.

3.1.2.4.1 Pertinent Concepts and Assumptions

In wetlands characterized by annual non-woody vegetation, above- and below-ground biomass and litter production contribute largely to the annual increase in soil organic carbon. Thus, when annual soil carbon stock changes are quantified, they already include changes in the biomass and litter pools. Project Proponents shall not double-count carbon stock changes in above- and below-ground biomass and the soil pool. Net increases in the soil carbon pool shall be measured using methods described in the Measurement Module (MM-W/RC).

The actual net GHG removals shall be estimated using the equations in this section. When applying these equations for the ex-ante calculation of net GHG removals, Project Proponents shall provide estimates of those parameters that are not available before commencement of monitoring activities. Project Proponents should retain a conservative approach in making these estimates, i.e., not underestimate actual emissions or overestimate GHG removals.

Equation 7

$$\Delta C_{ACTUAL_MW} = \Delta Cs_{MW} + fGHG_{MW} + fEFF_{MW}$$

WHERE

ΔC_{ACTUAL_MW}	is the cumulative total of carbon stock changes and GHG emissions of the Project area during the reporting period under the Project Scenario of managed wetlands
ΔCs_{MW}	is the cumulative total of carbon stock changes of the Project area during the reporting period under the Project Scenario
$fGHG_{MW}$	is the cumulative total of GHG emissions as a result of implementation of the Project activity
$fEFF_{MW}$	is the cumulative total emission from fossil fuel combustion for the Project area during the reporting period
Comment	The terms will be added in case GHG exchanges are going in the same direction (from biosphere to atmosphere or vice versa) and subtracted when in opposite directions

3.1.3 Parameter Tables

PARAMETERS ORIGINATING IN OTHER MODULES

DATA/ PARAMETER	$\Delta Cs_{_MW}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 7
DESCRIPTION	Cumulative total of carbon stock changes for the Project area during the reporting period under the managed wetland Project Scenario
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Relevant information shall be included in the GHG Project Plan

DATA/ PARAMETER	$fGHG_{MW}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 7
DESCRIPTION	Cumulative total of GHG emissions for the Project area during the reporting period as a result of implementation of the Project Activity
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Relevant information shall be included in the GHG Project Plan

DATA/ PARAMETER	$fEFF_{MW}$
DATA UNIT	MT CO_2e

USED IN EQUATION	Equation 7
DESCRIPTION	Cumulative total emission from fossil fuel combustion for the Project area during the reporting period
MODULE PARAMETER ORIGINATES IN	E-FFC
COMMENT	Included if fossil fuel combustion emissions have been determined to be significant using Tool T-SIG

3.2 (PS-TW) PROJECT CONDITION IS TIDAL WETLANDS

3.2.1 Scope, Background, Applicability, and Parameters

3.2.1.1 SCOPE AND BACKGROUND

This Module provides guidance for estimating ex-ante and ex-post carbon stock changes and GHG emissions related to tidal wetlands construction and restoration. The Module provides specific guidance for determining applicability, monitoring Project implementation, stratification, and estimating carbon stock changes and GHG emissions.

3.2.1.2 APPLICABILITY

This Module is always mandatory for use with tidal wetlands. Tidal wetland restoration includes tidal marshes and eelgrass meadows in the San Francisco Bay Estuary. Hydrologic management and the infrastructural modification activities requirement for implementation of tidal wetlands include levee breaching and construction, earth-moving, levee construction, and other activities related to re-introducing tidal action and application of dredged material. The following conditions must be met to apply this Module:

- The Project activity is restoration of tidal wetlands where the Baseline Scenario is seasonal wetlands, agricultural lands, or open water;
- This Module is not applicable where application of nitrogen fertilizer(s), such as chemical fertilizer or manure, occurs in the Project area during the Crediting period.

3.2.1.3 PARAMETERS

This Module produces the following parameter.

PARAMETER	SI UNIT	DESCRIPTION
ΔC_{actual_TW}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Project area during the reporting period under the tidal wetland Project Scenario
The notation for this parameter in the Methodology Framework Module is expressed in its generic form as ΔC_{actual} in Equation 1		

3.2.2 Procedure

3.2.2.1 ESTABLISHMENT AND DOCUMENTATION OF THE GHG BOUNDARY

Guidance for definition of geographic and temporal boundaries is provided in the Methodology Framework Module (MF-W/RC). The Project Proponent must provide a detailed description of the geographic boundaries for Project activities. Project activities may occur on more than one discrete area of land, and each area must meet the Project eligibility requirements.

3.2.2.1.1 Consideration of Sea Level Rise

In the determination of geographical Project boundaries and strata, Project Proponents shall estimate relative sea level rise and assess the potential for expanding the Project area to account for wetland migration, inundation, and erosion over the Project period. The Project Proponent shall estimate relative sea level rise within the Project area based on peer-reviewed literature and/or federal, state, and regional planning documents applicable to the region. The assessment of potential wetland migration, inundation, and erosion with projected sea level rise must account for topographical slope, management, sediment supply, and tidal range. Project Proponents shall be conservative, i.e., use the upper range of estimated sea level rise values for the 40-year Project period.

When assessing the horizontal migration potential of tidal wetlands, Project Proponents must consider the topography of the adjacent lands and any migration barriers that may exist. In general, concave-up slopes may cause “coastal squeeze,” while straight or convex-up gradients are more likely to provide the space required for lateral movement. The potential for tidal wetlands to rise vertically with sea level rise is sensitive to suspended sediment loads in the system. Project Proponents may use available peer-reviewed data and models to estimate

sediment load thresholds above which wetlands are not predicted to be submerged (Swanson et al. 2015). The vulnerability of tidal wetlands to sea level rise and conversion to open water is also related to tidal range. In general, the most vulnerable tidal wetlands are those in areas with a small tidal range, those with elevations low in the tidal frame, and those in locations with low suspended sediment loads.

3.2.2.2 PROJECT STRATIFICATION

Strata shall be delineated using spatial data (e.g., maps, GIS, classified imagery). Strata must be spatially discrete and stratum areas must be known. Areas of individual strata must sum to the total Project area. For estimation of ex-ante carbon stock changes and GHG emissions, strata should be defined based on parameters that affect carbon sequestration or GHG emissions and/or that are key variables for the methods used to measure changes in carbon stocks. Different soil and plant communities will likely have different carbon and GHG dynamics. Potential strata criteria are as follows:

- Tidal wetland elevation;
- Vegetation type and species, such as eelgrass meadows;
- Age class;
- Water quality (e.g., salinity, nutrient inputs, distance from source, etc.). See discussion below for relevance to CH_4 emissions;
- Hydrology (e.g., wetland water depth, depth of eelgrass meadow);
- Soil type (e.g., organic or mineral soils, soil texture);
- Areas of varying infrastructural modification (e.g., earth-moving).

Tidal wetlands may also be stratified according to salinity with relevance for CH_4 emissions. It is generally understood that wetlands exposed to high concentrations of sulfate (an anion present in seawater) emit CH_4 at relatively low rates due to low rates of CH_4 production. The presence of sulfate in tidal marsh soils allows sulfate-reducing bacteria to outcompete methanogens for energy sources, consequently inhibiting CH_4 production (Poffenbarger et al. 2011). However, sulfate can be reduced to sulfide in marsh soils or sulfate availability can be limited by diffusion or oxidation-reduction conditions; thus, the inhibitory effect of marine-derived saline water can be affected by site-specific conditions that allow CH_4 production to persist (Megonigal et al. 2004; Weston et al. 2011). Moreover, temporal and spatial variation in sources and sinks for sulfate and CH_4 can create conditions where both processes can coexist (Callaway et al. 2012). Therefore, estimates of CH_4 emissions and corresponding stratification may require direct measurements or conservative estimates as described below.

Established strata may be merged if reasons for their establishment have disappeared or have proven irrelevant to key variables for estimating net GHG emission reductions. In the GHG Project Plan, Project Proponents shall present an ex-ante stratification of the Project area or justify

the absence of stratification. Stratification for ex-ante estimations shall be based on the Project Management Plan. Aerial or satellite imagery used to delineate strata shall be verified in the field. The ex-ante defined number and boundaries of the strata may change during the crediting period (ex-post). The ex-post stratification shall be updated if natural or anthropogenic impacts or other factors add variability to the carbon stock changes or GHG emissions of the Project area.

3.2.2.2.1 Eelgrass Meadows

Seagrasses that include eelgrass (Zostera marinas) are among the planet's most effective natural ecosystems for sequestering (capturing and storing) carbon. However, there is limited data and quantifying and modeling their GHG removal capacity is critical for successfully managing eelgrass ecosystems to maintain their substantial abatement potential (Macreadie et al. 2014). Given the tendency of eelgrasses to respond differently under different light and depth regimes, projects may differentiate between eelgrass meadow sections that occur at different depths given discrete—or relatively abrupt— bathymetric and substrate changes. For eelgrass meadow restoration Projects in areas with existing eelgrass meadows, Project Proponents must quantify the percentage of natural meadow expansion that can be attributed to the restoration effort. Existing meadows are not eligible for inclusion in calculations of Project emissions, even in cases where the restored meadow influences carbon emission rates in existing meadows.

New beds that result from natural expansion must be contiguous with restored meadow plots to be included in Project accounting, unless Project Proponents can demonstrate that non-contiguous meadow patches originated from restored meadow seeds. This may be done through genetic testing or estimated as a percentage of new meadow in non-contiguous plots observed no less than 4 years after the Project start date (McGlathery et al. 2012). This percentage must not exceed the proportion of restored meadow area relative to the total eelgrass meadow area extent, and Project Proponents must demonstrate the feasibility of current-borne seed dispersal from the restored meadow. In cases where a restored meadow coalesces with an existing meadow(s), Project Proponents must delineate the line at which the two meadows joined. Project Proponents may use either aerial observations showing meadow extent or direct field observations.

3.2.2.3 MONITORING PROJECT IMPLEMENTATION

As described in the Methodology Framework Module (MF-W/RC), Project Proponents shall include a single Monitoring Plan in the Project Plan that includes a description of Baseline and Project monitoring and estimation of carbon stock changes and emissions. Information shall be provided to document the following:

- The geographic coordinates of the Project boundary (and any stratification inside the boundary) are established, recorded, and archived;

- Standard operating procedures (SOPs) and quality control/quality assurance (QA/QC) procedures for field data collection and data management are applied;
- Use or adaptation of relevant practices already applied in tidal wetland monitoring, or available from published relevant materials, are implemented;
- The monitoring plan, together with a record of implemented practices and monitoring during the Project, shall be available for validation and verification.

3.2.2.4 QUANTIFY PROJECT CARBON STOCK CHANGES AND GHG EMISSIONS

Carbon stock changes and GHG emissions shall be estimated using the methodology described in the Methods Module (MM-W/RC), which provides the appropriate methods for measuring and estimating emissions for Project and Baseline activities (use Baseline Modules BL-Ag, BL-OW, or BL-SW). The methods listed in the Methods Module may be used alone or in tandem. For GHG emissions measurements for tidal wetland Project activities, chamber and eddy covariance methods are appropriate. The Methods Module provides guidance, quality assurance and control, precautions and recommendations for chamber and eddy covariance techniques. Emissions can be estimated using appropriate proxy measurements from systems with similar carbon dynamics or estimates for similar situations documented in the peer-reviewed literature. In this case, the environmental setting for the estimates shall be detailed. Also, there shall be a comprehensive demonstration of conservativeness and applicability.

As discussed above, CH_4 fluxes are generally influenced by salinity that can affect stratification. CH_4 emissions can be measured using methods described in the Methods Module. These methods can be used to directly determine and characterize the spatial and temporal variability resultant from topography, temperature, vegetation, and water levels. Alternatively, a conservative estimate of CH_4 emissions requires measurement in the stratum where and when emissions are likely to be the largest.

That is, chamber or eddy covariance measurements shall be conducted at times and places in which CH_4 emissions are expected to be the highest based on expert judgment, datasets, or literature. These are likely to be the wettest strata that support emergent vegetation, but may include stagnant pools of water. If eddy flux towers are used for the conservative approach, they will be placed so that the footprint lies in the stratum with the highest CH_4 emissions for at least 50% of the time.

Methodologies used when measuring GHG fluxes under inundated conditions (notably for eelgrass) need to sample and quantify GHG fluxes in different tidal conditions, to prevent underestimation of GHG emission due to measurements made only during low tides.

Where a default factor approach is used based on salinity, the average or low value of salinity shall be measured in shallow pore water of soils within 30 cm of land surface using acceptable

technology or analytical determination of total dissolved solids. Sulfate concentrations shall also be determined when salinity is measured using standard analytical methods at a certified laboratory. The salinity average shall be calculated from measurements during periods when peak CH_4 emissions are expected. When the frequency of salinity measurements is less than monthly for 1 year, the minimum salinity value shall be used.

A default emission factor (Poffenbarger et al. 2011) may be used with caution (see exceptions below) where the salinity average or salinity minimum is greater than 18 parts per thousand. In this case, the annual rate of CH_4 emissions (MT CO_2e) of a stratum in presence of salinity is:

Equation 8

$$\mathbf{fGHG_{TWI} = \ 0.0045\ t\ CH_4\ acre^{-1}\ yr^{-1}\ = 0.011\ t\ \ CH_4\ \ ha^{-1}\ yr^{-1}}$$

The default emission factor shall not be used where oxidation-reduction conditions or sulfate concentrations are such that CH_4 production may not be inhibited. For example, Winfrey and Ward (1983) demonstrated greatly increased CH_4 pore-water concentrations with decreasing sulfate to chloride ratios in intertidal sediments below 0.01. Morris and Riley (1966) reported a sulfate chloride ratio of 0.14 +/- 0.00023 for the world's oceans.

Specific applicability conditions follow for the use of the default factor:

- The default factor shall not be used when sulfate/chloride ratios are less 0.01;
- In intertidal areas where sulfate-to-chloride ratios are likely near or below 0.01, CH_4 fluxes shall be measured using methods described in the Methods Module (MM-W/RC).

Project Proponents may also estimate GHG emissions using locally calibrated and peer-reviewed biogeochemical models as per guidance in the Modeling Module (MODEL-W/RC). Project Proponents shall provide parameters or data used for modeling during the crediting period. Parameter estimates shall be based on measured data or existing published data that can be demonstrated as applicable. In addition, Project Proponents must be conservative in estimating parameters. If different values for a parameter used in models or calculations are equally plausible, a value that does not lead to over-estimation of net GHG emission reductions must be selected and its use shall be documented. N_2O emissions are generally low, and even negative, in unenriched fresh and coastal marshes (Moseman-Valtierra 2011, 2012; Badiou et al. 2011; Wang et al. 2017; Yu et al. 2007; Liikanen et al 2009).

If Project activities include moving sediments, fossil fuel combustion emissions must be quantified during Project activities using methods described in the Methods Module E-FFC if determined to be significant, using the tool T-SIG. An ex-ante estimate of projected fuel usage shall be made.

Methods for measure above- and below-ground biomass and soil organic carbon stock changes are described in the Methods Module (MM-W/RC). Guidance for use of the mean value or replicate measurements in time and space in estimating carbon stock changes is in the Uncertainty (X-UNC) and Methodology Framework (MF-W/RC) Modules.

A 5-year interval is considered adequate for the determination of changes in soil carbon stocks. Specifically, soil coring measurements of carbon stock changes shall be conducted every 5 years after Project inception and placement of feldspar markers or sediment pins (Macreadie et al. 2014) where opening of the Project area would wash feldspar markers away due to tidal influence. Sediment pins are pounded into the ground to refusal, and sediment accretion is measured against the pin's height (US Geological Survey 2012).

If eddy covariance measurements are used to estimate carbon stock changes, continual monitoring shall occur from Project inception until calibrated and validated biogeochemical models documented in the peer-reviewed literature can effectively predict carbon stock changes. See the Model Module (MODEL-W/RC) for model-use requirements. As per guidance in the Measurement Module (MM-W/RC), aqueous carbon fluxes shall be accounted for. Project Proponents shall demonstrate that spatial and temporal heterogeneity is adequately represented in the estimation of carbon stock changes and GHG emissions. Biogeochemical models calibrated and validated for Project conditions shall be used to simulate cumulative Project carbon stock changes and GHG emissions for each reporting period.

3.2.2.4.1 Pertinent Concepts and Assumptions

In wetlands characterized by annual non-woody vegetation, over the reporting period, above- and below-ground biomass and litter production represent a large proportion of the increase in the soil carbon pool. Thus, when annual soil carbon stock changes are quantified, they already include changes in the biomass and litter pools. Project Proponents shall not double-count carbon stock changes in above- and below-ground biomass and the soil pool. Net increases in the soil carbon pool as the result of biomass contributions shall be estimated using methods described in the Methods Module (MM-W/RC).

Project Proponents using non-Project specific values must demonstrate use of conservative estimates.

Equations and methods for measuring Project carbon stock changes and GHG emissions are provided in the Methods Module (MM-W/RC). The Project carbon stock change and GHG emissions shall be estimated using the equations in this section. In applying these equations ex-ante, Project Proponents shall provide estimates before the start of the Crediting period and monitoring activities. Project Proponents shall utilize a conservative approach in making these estimates. When in the Project Scenario allochthonous soil organic carbon accumulates as indicated by aqueous or particulate organic carbon entering the Project area, the net carbon stock change is estimated as follows:

Equation 9

$$\Delta C_{ACTUAL_TW} = \Delta Cs_{TW} + fGHG_{TW} - Eaq + fEFF_{TW}$$

WHERE

ΔC_{ACTUAL_TW}	is the cumulative total of carbon stock changes and GHG emissions (MT CO_2e) for the Project area during the reporting period
ΔCs_{TW}	is the cumulative total of carbon stock changes under the Project Scenario (MT CO_2e) for the Project area during the reporting period
$fGHG_{TW}$	is the cumulative total of biogenic GHG emissions for the Project area during the reporting period as a result of implementation of the Project activity (t CO_2e)
Eaq	is the deduction to account for allochthonous soil organic carbon (MT CO_2e) entering the wetland. See Methods Module (MM-W/RC) for Eaq measurements, and T-Sig for determination of significance of this flux
$fEFF_{TW}$	is the total emissions of fossil fuels for the Project area during the reporting period (MT CO_2e)
$Comment$	The terms will be added in case GHG exchanges are going in the same direction (from biosphere to atmosphere or *vice versa*) and subtracted when in opposite directions

Allochthonous carbon may enter the tidal wetland area from an outside source and may contribute to carbon accumulation at the site. However, it represents carbon assimilated by other sinks, and the Wetland Project area does not contribute to its removal from the atmosphere. For this reason, it should be quantified and deducted from the total carbon balance of the Project area, as a loss term. In the Project Scenario, net accumulation of allochthonous carbon must be subtracted from the net carbon balance of a wetland unless the Project Proponent can document that no other entity may claim its GHG emission reductions or removals (i.e., that no other entity may make an ownership claim to the emission reductions or removals for which credits are sought) and if its storage in the tidal wetland decreases the rate of its decomposition compared to what it would be in the absence of the Project (i.e., the case the tidal wetland was not implemented). In the Baseline Scenario, net accumulation of allochthonous carbon can be accounted for and subtracted from the Baseline total carbon stock change, or can be conservatively set to zero.

3.2.3 Parameter Tables

PARAMETERS ORIGINATING IN OTHER MODULES

DATA/ PARAMETER	ΔCs_{TW}
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 9
DESCRIPTION	Cumulative total of carbon stock changes under the tidal wetland Project Scenario for the Project area during the reporting period
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Relevant information shall be included in the GHG Project Plan

DATA/ PARAMETER	$fGHG_{TW}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 9
DESCRIPTION	Cumulative total of GHG emissions of the Project area during the reporting period as a result of implementation of the Project activity
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Relevant information shall be included in the GHG Project Plan

3.3 (PS-RC) PROJECT CONDITION IS RICE CULTIVATION

3.3.1 Scope, Background, Applicability, and Parameters

3.3.1.1 SCOPE AND BACKGROUND

This Module provides methods for estimating ex-ante and ex-post GHG emissions reductions related to rice cultivation (RC). The Module provides specific guidance for determining applicability, monitoring Project implementation, stratification, and estimating carbon stock changes and GHG emissions.

3.3.1.2 APPLICABILITY

This Module is mandatory when the Project activity includes rice cultivation on organic and highly organic mineral soils in the Sacramento-San Joaquin Delta. The Module is applicable for estimating Project carbon stock changes and GHG emissions for Project areas planned for rice cultivation where agriculture is the Baseline Activity as discussed in the agricultural Baseline Module (BL-Ag). The rice cultivation Project activity includes a combination of hydrologic management changes, rice planting, and infrastructural modification. Infrastructural modification includes drainage modification and earth-moving. Hydrologic management includes modification of existing water supply and drainage facilities to ensure shallow flooding of the rice fields during the spring and summer.

The following conditions must be met to apply this Module:

- The Project area must be on agricultural lands where crops are grown and/or animals are grazed on areas of organic soils as in the Sacramento-San Joaquin Delta, or seasonal wetlands;
- The Project Activity is rice cultivation where there are organic soils;
- Best management practices aimed to minimize CH_4 emissions and maximize GHG emission reduction should be used in rice cultivation.

3.3.1.3 PARAMETERS

This Module produces the following parameters:

PARAMETER	SI UNIT	DESCRIPTION
ΔC_{actual_RC}	MT CO_2e	Cumulative total carbon stock changes and GHG emissions for the Project area during the reporting period under the Rice cultivation Project Scenario
The notation for this parameter in the Methodology Framework Module is expressed in its generic form as ΔC_{actual} in Equation 1		

3.3.2 Procedure

3.3.2.1 ESTABLISHMENT AND DOCUMENTATION OF THE GHG BOUNDARY

The geographic boundaries of a Rice Project are fixed ex-ante. Guidance for defining geographic and temporal boundaries is provided in the Methodology Framework Module (MF-W/RC). The Project Proponent must provide a detailed description of the geographic boundaries for Project activities. Project activities may occur on more than one discrete area of land, and each area must meet the Project eligibility requirements.

3.3.2.2 PROJECT STRATIFICATION

If the Project Activity area is not homogeneous (and where applicable), Project Proponents shall implement stratification to improve the accuracy and precision of carbon stock estimates. For estimation of ex-ante carbon stocks, strata should be defined based on parameters that affect GHG removal or emissions and/or that are key variables for the methods used to measure changes in carbon stocks. The key factors affecting GHG emissions are fertilization and soil organic carbon contents. Potential strata criteria are described in Table 21.

Table 21: Factors and Practices that Can Be Used for Stratification and Their Effects on GHG Emissions and Removals

STRATIFICATION FACTOR OR PRACTICE	DESCRIPTION	POTENTIAL GHG EFFECT
Rice water management practices	Depth of water	Affects CO_2 sequestration and CH_4 emissions
Rice water management practices	Flow through or limited or zero outflow	Affects CH_4 emissions
Rice cultivar	Time for maturity varies among cultivars	Affects length of growing season, which affects CO_2 sequestration and GHG emissions
Soil classification and chemical composition	Soil organic matter, pH, carbon-to-nitrogen ratio, salinity, and texture	Soil organic matter is a key determinant of GHG emissions. The other factors affect GHG emissions and removal
Soil hydrology	Depth to groundwater, oxidation-reduction conditions	Depth to groundwater is an important determinant of GHG emissions on organic soils
Fertilization rates and timing	Optimum fertilization rates vary for different soils (Espe et al. 2015)	N_2O emissions affected by fertilization rates and timing (Ye and Horwath 2014)

In the GHG Project Plan, the Project Proponents shall present an ex-ante stratification of the Project area or justify the absence of stratification. Stratification for ex-ante estimations shall be based on the Project Management Plan. Aerial photography or satellite imagery used to delineate strata shall be verified in the field. The ex-ante defined number and boundaries of the strata may change during the Crediting period (ex-post). The ex-post stratification shall be updated if natural or anthropogenic impacts or other factors add variability to the growth pattern or emissions of the Project area.

3.3.2.3 MONITORING PROJECT IMPLEMENTATION

As described in the Methodology Framework, Project Proponents shall include a single Monitoring Plan in the GHG Project Plan that includes a description of Baseline and Project monitoring and estimation of carbon stock changes. Information shall be provided in the Monitoring Plan (as part of the Project Plan), to establish the following:

- The geographic coordinates of the Project boundary (and any stratification inside the boundary) are established, recorded, and archived;
- Commonly accepted principles of rice cultivation for minimizing GHG emissions in the Delta are implemented as described in the Appendix B;
- Standard operating procedures (SOPs) and quality control/quality assurance (QA/QC) procedures for field data collection and data management are implemented.

The Monitoring Plan, together with a record of implemented practices and monitoring during the Project, shall be available for validation and verification.

3.3.2.4 QUANTIFY PROJECT CARBON STOCK CHANGES AND GHG EMISSIONS

Carbon stock changes and GHG emissions shall be measured using the methodology described in this section and the Measurement Module (MM-W/RC), which provides the appropriate methods for measuring carbon stocks and GHG emissions for Project activities. The methods listed in the Measurement Module may be used alone or in tandem with the other methods listed. For emission/removal measurements for Rice Cultivation Project activities, chamber and eddy covariance methods are appropriate. Monitoring shall occur during the entire calendar year. Emissions and removals can be estimated using appropriate proxy measurements in similar situations. If proxy measurements are used, the environmental setting relevance and scientific validity shall be detailed. Also, there shall be a demonstration of conservativeness.

Biogeochemical models that meet the requirements described in the Model Module (MODEL-W/RC) can be used for estimating GHG emissions/removals. Project Proponents shall provide transparent calculations or estimates for the parameters used for calculations or modeling during the Crediting period. These estimates shall be based on measured data or existing published data where appropriate. In addition, Project Proponents shall apply the principle of conservativeness. If different values for a parameter are equally plausible, a value that does not lead to demonstrable over-estimation of net GHG emission reductions must be selected. If Project activities include moving sediments, construction, and the like, fossil fuel combustion emissions must be quantified during Project activities using methods described in the Module E-FFC, if determined to be significant using the T-SIG tool. The ex-ante estimate of fuel consumption shall be based on projected fuel usage.

Measurement methods can be found in the Measurement Module (MM-W/RC) for calculating carbon stock changes and GHG emissions. If the eddy covariance technique is used, carbon in harvested biomass must be accounted for as described in the Measurement Module. A 5-year frequency is considered adequate for the determination of changes in soil carbon stocks. Project Proponents shall demonstrate that spatial and temporal heterogeneity is adequately represented in the estimate of carbon stock changes and GHG emissions.

3.3.2.4.1 Pertinent Concepts and Assumptions

- Net increases in the soil carbon pool as the result of biomass contributions shall be estimated using methods described in the Measurement Module (MM-W/RC). Project Proponents shall not double count carbon stock changes in above- and below-ground biomass and the soil pool;
- It is assumed that 100% of the harvested biomass is eventually consumed, resulting in releases of CO_2 and CH_4, back into the atmosphere.The mass of the carbon in the harvested grain shall be counted in the carbon stock change.
- Net increases and/or avoided losses in the soil-organic-carbon pool as the result of rice cultivation shall be included;
- Exchanges of GHG shall be measured in the field under Project conditions or may be quantified by an acceptable proxy, reference sample plots, or field monitoring of similar sites, using approved local or national parameters, peer-reviewed biogeochemical models, or peer-reviewed literature;
- Project Proponents using non-Project specific values must use conservative estimates and demonstrate applicability.

Calculation of ΔC_{actual_RC} (cumulative total of the carbon stock changes and GHG emissions under the Project Scenario Rice Cultivation) shall be made using the equations in this section. When applying these equations for the ex-ante calculation of actual net GHG removals by sinks, Project Proponents shall provide estimates of the values of those parameters that are not available before the commencement of monitoring activities. Project Proponents should retain a conservative approach in making these estimates.

The net carbon stock change and GHG emissions are estimated using the following general equation.

Equation 10

$$\mathbf{\Delta C_{ACTUAL_RC} = \Delta Cs_{RC} + fGHG_{RC} + fEFF_{RC}}$$

WHERE

ΔC_{ACTUAL_RC}	is the cumulative total of carbon stock changes and GHG emissions (MT CO_2e) under the Rice cultivation Project Scenario for the Project area during the reporting period
ΔCs_{RC}	is the cumulative total of carbon stock changes (MT CO_2e) under the Project Scenario for the Project area during the reporting period
$fGHG_{RC}$	is the cumulative total of GHG emissions (t CO_2e) as a result of implementation of the Project activity for the Project area during the reporting period
$fEFF_{RC}$	is the total emission from fossil fuel combustion for the Project area (MT CO_2e yr^{-1}) during the reporting period
Comment	The terms will be added in case GHG exchanges are going in the same direction (from biosphere to atmosphere or vice versa) and subtracted when in opposite directions

Equation 11 can be used to estimate the N_2O emission (kg N_2O ha^{-1} yr^{-1}) from rice cultivation for soil organic carbon (SOC in %) contents varying between 5 and 35% in the Delta (Ye and Horwath 2016a). In this region nitrogen fertilization at rates up to 160 kg N ha^{-1} did not affect annual N_2O emissions (Ye and Horwath 2016b; Morris et al. 2017).

Equation 11

$$\mathbf{N_2O\ emission} = \mathbf{2.59 - 0.09 \times SOC}$$

3.3.3 Parameter Tables

PARAMETERS ORIGINATING IN OTHER MODULES

DATA/ PARAMETER	ΔCs_{RC}
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 11

DESCRIPTION	Cumulative total of carbon stock changes for the Project area during the reporting period under the rice cultivation Project Scenario
MODULE PARAMETER ORIGINATES IN	MM-W/RC or MODEL-W/RC
COMMENT	Relevant information shall be included in the GHG Project Plan

DATA/ PARAMETER	$fGHG_{RC}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 11
DESCRIPTION	Cumulative total of GHG emissions for the Project area during the reporting period as a result of implementation of the Project activity
MODULE PARAMETER ORIGINATES IN	MM-W/R or MODEL-W/RC
COMMENT	Relevant information shall be included in the GHG Project Plan

DATA/ PARAMETER	$fEFF_{RC}$
DATA UNIT	MT CO_2e
USED IN EQUATION	Equation 11
DESCRIPTION	Cumulative total emission from fossil fuel combustion for the Project area during the reporting period

MODULE PARAMETER ORIGINATES IN	E-FFC
COMMENT	Relevant information shall be included in the GHG Project Plan

4 METHODS MODULES

PREFACE

The objective of this methodology is to describe quantification procedures for the reduction of greenhouse gas (GHG) emissions through conversion of land to wetlands and rice cultivation. This methodology achieves GHG emissions reductions by 1) halting or greatly reducing soil organic carbon oxidation; and 2) increasing soil organic storage by restoring wetlands (tidal and non-tidal) and cultivating rice.

The methodology has been written in a modular format; Project Proponents can choose the applicable Modules for their specific Project and site. First, the Framework Module provides background and an overarching description of the Methodology requirements and Modules. All Projects must meet the requirements outlined in the Methodology Framework Module (MF-W/RC). Next, the remaining Modules provide guidance for Baseline and Project Scenario quantification, methods, modeling, calculation of uncertainty, and other quantification tools. From these supporting Modules, Project Proponents will select the relevant components for a Project.

The Methods Modules and Tools in this chapter describe: 4.1) how to measure carbon stock changes and GHG emissions (MM-W/RC); 4.2) how to estimate carbon stock changes and GHG emissions using biogeochemical models (MODEL-W/RC); 4.3) how to quantify fossil fuel emissions (E-FFC); 4.4) how to quantify uncertainty (X-UNC); 4.5) how to estimate risks (T-Risk); 4.6) how to conduct significance testing (T-SIG); and 4.7) how to design field plots (T-PLOT).

PARAMETERS

Table 22 through Table 24 and Figure 4 below describe the parameters needed to quantify carbon stock changes and GHG emissions for Wetland Restoration and Rice Cultivation Projects. The methodological options for quantifying each variable are listed for each Baseline and Project activity type.

Parameters in Table 24 can be estimated using appropriate measurement data documented in the peer-reviewed literature or estimates from proxy systems. If proxy data are used, documentation of sufficiently similar climate, soil, hydrologic conditions, and vegetation conditions are required.

Table 22: Description and Estimation Methods of Carbon Stock Changes and GHG Emissions Parameters for Baseline and Project Scenarios

PARAMETER	SI UNIT	DESCRIPTION	ESTIMATION METHODS
ΔC_{BSL}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Baseline Scenario	• Biogeochemical models • Eddy covariance • Subsidence measurements • Whole ecosystem chambers • Aqueous carbon flux measurements • C inventories
ΔC_{actual}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Project Scenario	• Eddy covariance • Biogeochemical models • Soil core collection and analysis using feldspar markers and tidal pins • Aqueous carbon flux measurements • Whole ecosystem chambers • C inventories

Table 23: Emissions Sources Parameters, Description, and Estimation Methods

PARAMETER	SI UNIT	DESCRIPTION	ESTIMATION METHODS
ΔGHG_{BSL}	MT CO_2e	Cumulative net GHG fluxes for the Baseline Scenario	• Chamber measurements • Biogeochemical models • Eddy-covariance measurements • Subsidence measurements
ΔGHG_P	MT CO_2e	Cumulative net GHG fluxes due to Project Activities	• Chamber measurements • Biogeochemical models • Eddy covariance
E_{FFC}	MT CO_2e	Annual GHG emissions due to combustion of fossil fuel	• Module E-FFC, provides guidance for fossil fuel emissions estimates

Figure 4: Relation of Project and Baseline Activities to Methods for Determination of Carbon Stock Changes and GHG Emissions

Models requirement are described in Module (MODEL-W/RC).

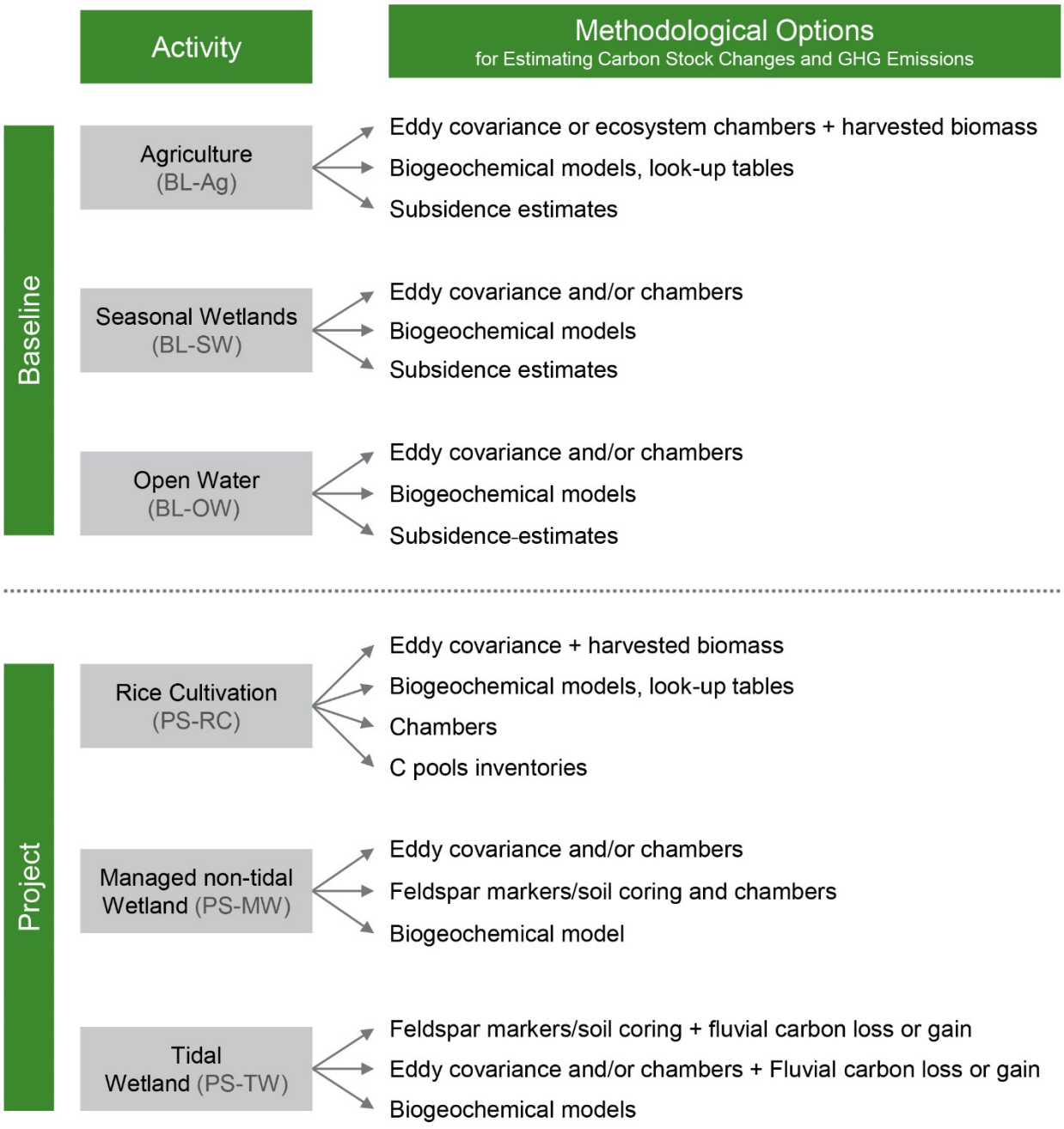


Table 24: Description and Estimation Methods of Carbon Pools Changes

PARAMETER	SI UNIT	DESCRIPTION	ESTIMATION METHODS
$\Delta C_{ag\ biom}$	MT CO_2e	Cumulative above-ground carbon stock changes	Allometric equations, leaf area index, digital photography, destructive methods
$\Delta C_{bg\ biom}$	MT CO_2e	Cumulative below-ground biomass carbon stock changes	Multiplication of accumulated above-ground biomass times published root:shoot ratio, destructive methods
ΔC_{litter}	MT CO_2e	Litter carbon stock changes	Direct measurements using decomposition bags or indirect estimates from isotopic technique and/or modeled estimates based on environmental controls
$\Delta C_{cr,}$	MT CO_2e	Crop residue remaining in field	Destructive methods for harvest and determination of carbon content of biomass
ΔC_{soil}	MT CO_2e	Changes in soil carbon stock	Soil coring

4.1 (MM-W/RC) MEASUREMENT METHODS TO ESTIMATE CARBON STOCK CHANGES AND GHG EMISSIONS

4.1.1 Scope

This Module provides direction for ex-ante and ex-post estimation of carbon stock changes and GHG emissions for Baseline and Project conditions and data collection for inputs to biogeochemical models.

4.1.2 Applicability

This Module is applicable for all Baseline conditions and Project activities. The Methodology Framework Module (MF-W/RC) describes the applicable conditions and relevant Project activities for the use of the methodology.

4.1.3 Parameters and Estimation Methods

Net exchanges of GHG can be estimated through two different approaches: 1) using a mass balance approach to quantify carbon stock differences between two points in time; or 2) quantifying carbon losses and gain. The latter approach focuses on the processes involved and thus on fluxes: biogenic CO_2, CH_4, and N_2O fluxes, and fossil fuel emissions. Some parameters, such as soil carbon pools, are more easily and traditionally measured using a mass-balance approach. Others, such as fossil fuel emissions, are only measured as fluxes.

Eddy covariance, chambers, and biogeochemical models measure or estimate carbon uptake and release (or directly measure or estimate their net balance) at any given moment. Their cumulative value over time (usually a year) is equivalent to the carbon stock change for that year. Additional C losses or gains from the ecosystem, such as harvested grain and aqueous carbon loads, should be considered in addition to gas exchange measurements. The mass balance approach (Approach 1) can be based on inventories of carbon stocks in the ecosystems and their difference in time. Above-ground biomass, below-ground biomass, dead biomass, litter, soil carbon, and harvested biomass need to be measured at the beginning and end of the reporting period. The cumulative value of carbon gains and losses over time (usually a year) is equivalent to the carbon stock mass change for that time. Additional methods are possible and can combine mass balance and flux quantification. For example, an additional method to measure the net ecosystem CO_2 flux is to measure the difference between NPP (net primary productivity) and the heterotrophic respiration.

The general equations used to quantify biogenic GHG fluxes and C stock changes under both Baseline and Project Scenarios are:

Equation 12

$$\Delta C_S + fGHG = \sum_{t=1}^{40}\left(\sum_{i=1}^{n}\left(E_{CO2,i} + E_{CH4,i} + E_{N2O,i} + Cgr_i + Eaq\right)\right)$$

AND

Equation 13

$$\left(\mathbf{E_{CO2,i}} + \mathbf{E_{CH4,i}}\right) = \left(\Delta\mathbf{C_{ag\ biom,i}} + \Delta\mathbf{C_{bg\ biom,i}} + \Delta\mathbf{C_{dead\ matter,i}} + \Delta\mathbf{C_{soil,i}}\right)$$

WHERE

$\Delta Cs + fGHG$	is the cumulative carbon stock changes and/or net emission and removal of CO_2, CH_4, and N_2O (MT CO_2e) for the entire Project area during the reporting period
$\mathbf{E_{CO2,i}}$	is the annual net flux of CO_2 for the stratum $\mathbf{i}$ (MT CO_2e yr^{-1})
$\mathbf{E_{CH4,i}}$	is the annual net flux of CH_4 for the stratum $\mathbf{i}$ (MT CO_2e yr^{-1})
$\mathbf{E_{N2O,i}}$	is the annual net flux of N_2O for the statum $\mathbf{i}$ (MT $CO_2e.yr^{-1}$)
i	is the stratum within the Project boundary
n	is the number of strata within the Project boundary
Eaq_i	is the annual net aqueous exchange of carbon in drainage water (MT CO_2e yr^{-1})
t	is the year of the Project reporting period
Cgr_i	is the carbon removal in harvested biomass in the stratum (MT CO_2e yr^{-1})
$\Delta C_{ag_biom,i}$	is above-ground biomass carbon pool change
$\Delta C_{bg_biom,i}$	is below-ground biomass carbon pool change
$\Delta C_{dead\ matter,i}$	is the change in litter and dead matter (including crop residues left in the field) carbon pool
$\Delta C_{soil,i}$	is the change in the soil carbon pool

The left part of equation 12 represents annual carbon fluxes measured with eddy covariance or chambers and the right part the sum of the different carbon pools stock changes over the same time. Therefore, over the same period of time, the net GHG removals and emissions correspond to the change in carbon stocks of all ecosystem pools.

Signs for the storage and flux terms should be used accordingly. Carbon moving from the atmosphere to the biosphere will result in a positive storage term (ΔC_S). However, in case of

GHG fluxes ($fGHG$ and $fEFF$), a positive sign is often used to indicate emissions to the atmosphere. The different terms will be added when GHG exchanges are in the same direction (going from biosphere to atmosphere or *vice versa*), and subtracted when in opposite direction, e.g. when carbon storage counteracts CH_4 and N_2O emissions.

It is assumed that 100% of the harvested biomass is eventually consumed and released as CO_2 and CH_4 back into the atmosphere.

Net GHG exchanges should be converted to MT CO_2e based on global warming potentials (GWP) in the latest version of ACR Standard.

Each method listed below is discussed with an introduction, method-specific applicability conditions, quality control and assurance procedures, and method-specific equations:

- Eddy covariance
- Chamber measurements
- Harvested grain and biomass
- Aqueous carbon loads
- Subsidence measurements
- Soil coring
- Biomass carbon pools

Additionally, each method should follow development of international standards as laid out in pertinent scientific literature.

The methods listed can be used in combination with other listed methods. The selection of methods depends on Project and Baseline conditions, data availability, and the requisite level of certainty.

4.1.3.1 EDDY COVARIANCE

This section provides information about the use of eddy covariance techniques to measure gas fluxes.

4.1.3.1.1 Introduction

The eddy covariance (EC) technique (Baldocchi et al. 1988) estimates fluxes of GHGs by relying on the concurrent measurements of fluctuations of vertical wind velocity and atmospheric concentration of GHGs (e.g., CO_2, CH_4, N_2O). Using this method GHG fluxes can be measured at the ecosystem level and on a scale of generally a few hectares. Net ecosystem GHG fluxes

can be monitored for extended periods of time in a continuous manner. This approach is allowed for estimating carbon stock changes and GHG emissions for Baseline and Project conditions. When EC-measured net carbon flux is cumulated on an annual scale, it is defined as NEE (Net Ecosystem Exchange) or NEP (Net Ecosystem Production).

EC measurements provide an effective way to determine the net exchange of GHGs for a variety of ecosystems and have been used to measure Baseline (Teh et al. 2011) and Project carbon stock changes (Knox et al. 2015) on organic and highly organic mineral soils in the Delta for more than a decade (see Appendix B for additional information). For agricultural Baseline conditions (e.g., corn) on organic soils, CO_2 sequestration occurred as the result of plant photosynthetic uptake during the growing season. Oxidation of organic matter resulted in a net GHG emission. In addition, CO_2 assimilated into the harvested grain was removed from the ecosystem and resulted in an overall annual GHG emission. In contrast, for a permanently flooded wetland and, to a lesser extent, rice cultivation, flooding the soil during the warmest time of the year greatly reduced oxidation of soil organic matter resulting in a net GHG removal (Knox et al. 2015). Hatala et al. (2012) quantified GHG fluxes of rice and a pasture on organic soils in the Sacramento-San Joaquin Delta. The rates of carbon removal of rice were slightly lower than those of a riparian cottonwood stand about 50 km east of their site measured by Kochendorfer et al. (2011). The magnitude of CO_2 uptake at the Hatala et al. (2012) rice paddy was well below that from a restored marsh in southern California, where net carbon removal measured with EC varied between 6.8 and 18.5 tons CO_2 per acre (2.7 and 7.5 tons CO_2 ha^{-1}) during an 8-year study (Rocha and Goulden 2008), and higher than historical rates of accumulation in disturbed ecosystems of the same region (Canuel et al. 2009).

4.1.3.1.2 Applicability

The following applicability conditions apply to the use of eddy covariance.

- Stratification and landscape homogeneity in the EC footprint: The area of land contributing to the measured fluxes (footprint of the EC measurement) shall be quantified during the monitoring period and shall be shown to adequately represent the hydrologic, water quality and soil conditions, and management practices for the stratum. For example, the agricultural crop, water, and land management practices within the EC footprint shall be the same as for the entire stratum. Also, the average soil organic matter content within the EC footprint shall not vary more than 20% relative to the average soil organic matter content within the stratum.
- To avoid influences of adjacent land uses, the EC footprint shall be within the stratum that includes Project or Baseline land uses.
- The monitoring period using EC techniques shall be sufficient to quantify annual and interannual variations in GHG fluxes and to enable the use of biogeochemical models. The Project Proponents shall demonstrate that annual values for carbon stock changes for Baseline are representative. At least 1 year of monitoring is required for Baseline conditions. The Baseline Scenario shall be developed for the entire life of the Project using

site-specific data and/or models responding to requirements described in Module MODEL-W/RC. For Project conditions, continuous monitoring is required throughout the life of the Project unless biogeochemical models are calibrated with the EC data and can adequately predict GHG fluxes as described in Module MODEL-W/RC. At that point, EC measurements can be terminated.

4.1.3.1.3 Quality Assurance and Quality Control

Table 25: Quality Control/Assurance for Eddy Covariance Measurements

Describes quality assurance and quality control measures for EC measurements.

QUALITY CONTROL/ ASSURANCE TOPIC	CONSIDERATIONS	PROCEDURES
Temporal variability and frequency of measurements	GHG fluxes shall be measured with the EC method (Baldocchi et al. 1988) using parameters determined to be adequate for accurate EC measurements in peat soils and wetlands. Carbon accumulation rates shall be compared with measurements reported for natural and disturbed ecosystems in the region.	Standard EC practice shall be employed to measure the covariance between turbulence and C fluxes at 10 Hz intervals (every 0.1 s). These data shall be used to calculate half-hourly fluxes for net ecosystem exchange.
Filtering and removal of spurious data	EC data typically contain gaps and artificial spikes.	The sampling rate and averaging interval will allow for a 5 Hz cut-off for the cospectra between turbulence and carbon fluxes. After computing the fluxes, flux values with anomalously high and low friction velocity ($u^* > 1.2$ m s^{-1} and $|uw| < 0.02$) shall be filtered to constrain the analysis to periods where the air near the sensors was well-mixed. The random instrumental noise in each half-hour fluxes shall be assessed using bootstrapping technique. Fluxes from wind directions outside of the footprint of the target land-use

QUALITY CONTROL/ ASSURANCE TOPIC	CONSIDERATIONS	PROCEDURES
		type shall be excluded from the dataset. Missing data shall be treated conservatively so as to not overestimate the GHG benefit. Filtering software may be used to remove artificial spikes, which shall be greater than six standard deviations of the mean, within a 1-minute window and diagnostic instrument values that corresponded with bad readings, which are often correlated with rain or fog events. Typically, no less than 10% of the original flux data is excluded through this procedure. The Project Proponents shall justify a conservative application of any larger percentages.

Uncertainties associated with EC fluxes are described in details in the Uncertainty Module (X-UNC).

4.1.3.2 CHAMBER MEASUREMENTS

This section provides information about the use of chamber techniques to measure gas fluxes.

4.1.3.2.1 Introduction

For Project and Baseline conditions, gaseous fluxes of CO_2, CH_4, and N_2O from vegetation and open water can be measured using the chamber method (Livingston and Hutchinson 1995; Klinger et al. 1994). Chambers can be distinguished between whole ecosystem chambers and soil chambers, which are used to measure CO_2 and other GHG efflux from the soil surface. Ecosystem chambers measure the net balance between processes releasing and sequestering carbon from both vegetation and soil (Dore et al. 2003; Wang et al. 2013; Riederer et al. 2014), similarly to eddy covariance measurements. Measurements should account for temporal variations in fluxes, or be conducted when most significant anticipated fluxes are expected, in order to conservatively estimate net GHG emission reductions. For agricultural Baseline conditions in dry conditions, the chamber methods described in Livingston and Hutchinson (1995), Hutchinson and Mosier (1981), and Rolston (1986) are applicable. Chambers described in Lindau and DeLaune (1991) are appropriate for Project conditions (Lindau and DeLaune

1991; Miller et al. 2000; Majumdar 2013; Linquist et al. 2012). Recently, automated chambers have been used for estimating GHG fluxes (e.g., Picarro flux analyzer[6]). These instruments are acceptable for quantifying gaseous fluxes (Gatland et al. 2014; Christiansen et al. 2015).

Temperature inside the chambers shall be monitored. Gas must be mixed so that a concentration gradient does not occur. Mixing is normally accomplished by diffusion in small chambers, but a small fan may be required to ensure mixing in larger chambers. Gas samples can be taken with plastic syringes and stainless steel hypodermic needles. Samples shall be collected at least three times to allow a linear buildup of the concentration of the gas being measured after chamber closure. The overpressure created in sample vials/bags will ensure that atmospheric gases will not contaminate the sample gases. Silicone sealant is used to seal the injection hole in the rubber septum. The CH_4, CO_2, or N_2O concentrations of the gas samples can be measured on a gas chromatograph (GC). The flux of gases from the soils or wetland surfaces is calculated from the data obtained from the GC and can be then estimated using the equation:

Equation 14

$$\mathbf{fGHG} = \frac{\mathbf{V\Delta C}}{\mathbf{A\Delta t}}$$

WHERE

$fGHG$	is the GHG flux (GHG concentration area^{-1} time^{-1})
V	is the volume of chamber headspace volume
A	is the soil surface area
$\Delta C/\Delta t$	is the change in GHG concentration in time

The number of measurements shall be determined by characterizing spatial variability and meeting the required level of certainty. Chamber measurements shall account for heterogeneous landscapes within strata as described in Baseline and Project Modules. If present, chamber measurements shall be conducted within upland and lowland areas, and drainage ditches (Teh et al. 2011). Spatially weighted up-scaling methods are recommended for estimating annual GHG budgets across heterogeneous landscapes. Flux measurements shall be taken multiple times during a year for estimating seasonal or annual flux, and temporal and spatial repli-

[6] https://www.picarro.com/applications/emissions/greenhouse_gases

cation is important to reduce uncertainty. Boardwalks shall be used for accessing measurement sites to prevent disturbance of the marsh surface, soil compaction, and ebullition that would overestimate CH_4 fluxes.

Special care must be taken when estimating N_2O emissions using chambers. Fertilization and re-wetting events are especially important for N_2O budgets, where a single pulse event can account for >50% of the annual N_2O budget (Wagner-Riddle et al. 1997). Therefore, in order to accurately estimate N_2O emissions using manual chambers, deployment must include fertilization, irrigation, and precipitation events. These pulse events can encompass several days (1–30 days) and therefore must be evaluated at an appropriate time scale. Estimations of annual N_2O budgets from chamber measurements must account for the amount and frequency of fertilization, irrigation, and precipitation events in addition to lower-level N_2O emission rates that occur outside pulse events.

4.1.3.2.2 Applicability

The following applicability conditions apply to the use of chambers.

- The distribution of chamber measurement shall be shown to adequately represent the hydrologic, water quality and soil conditions, and land and water management practices for the stratum.
- The monitoring period using chamber measurements shall be sufficient to quantify possible annual variations in GHG fluxes. The Project Proponents shall demonstrate that annual values for GHG fluxes are representative.
- When measuring N_2O emissions using chambers, deployment must include fertilization, irrigation, and precipitation events.
- Monitoring must occur for Baseline establishment and renewal. At least 1 year of monitoring is required for Baseline conditions. Baseline field monitoring should be conducted seasonally for 1 year to determine the seasonal effects on GHG fluxes, or measurements can be made during the period of peak emissions (e.g., summer or fertilization events).
- For Project conditions, monitoring is required throughout the life of the Project unless the use of biogeochemical models calibrated with site data are shown to adequately predict GHG fluxes. At this point, chamber measurements may be terminated. For Project conditions, the monitoring frequency shall occur at least every 5 years for 1 year.

4.1.3.2.3 Quality Assurance and Quality Control

Quality assurance and control measures for chamber measurements are listed and discussed in Table 26.

Table 26: Quality Control/Assurance for Chamber Measurements

QUALITY CONTROL/ ASSURANCE TOPIC	CONSIDERATIONS	PRECAUTIONS AND SAFE-GUARDS	REFERENCE FOOTNOTE
Temperature	Ambient temperature should be preserved within the chamber. Solar heating of the enclosure surface can rapidly lead to increasing chamber temperatures.	Minimize deployment times, and for soil measurements, use shading of opaque materials, monitor chamber temperature	Livingston and Hutchinson 1995
DEPLOYMENT Development of a disturbance-free seal	Leakage can occur in unsaturated-zone soils especially during high winds.	Use weighted skirts around chambers and /or baffled, double-walled enclosures. Avoid high winds. Estimate leakage with a tracer gas.	Livingston and Hutchinson 1995; Crill et al. 1995; Davidson et al. 2002
DEPLOYMENT Surface compaction	Artificial gradients and mass inflow can be induced by surface compaction from foot traffic. Water-saturated soils are particularly susceptible.	Use of designated walkways, remote gas withdrawal from chambers	Livingston and Hutchinson 1995
DEPLOYMENT Vegetative disturbance	Disturbance of vegetation can affect exchange processes under study and influence plant mediated gas transport	Avoid cutting roots or severing stems and leaves	Crill et al. 1995
Field sample handling and processing	Sample container leakage and accuracy	Analyze gas samples within a few hours, analyze standards frequently	Crill et al. 1995

QUALITY CONTROL/ ASSURANCE TOPIC	CONSIDERATIONS	PRECAUTIONS AND SAFE-GUARDS	REFERENCE FOOTNOTE
Laboratory analysis	Potential for analytical error	Follow acceptable analytical protocol for trace gas analysis	Crill et al. 1995
Flux estimation	Time for concentration change measurements, chamber dimensions	Minimize sources of variability in sampling handling and analysis using maximum possible measurement period and number of independent samples. Two samples are not sufficient. Determine chamber volume precisely.	Crill et al. 1995

4.1.3.2.4 Equations

Where chambers are used to estimate cumulative GHG emissions, the following equation shall be used.

Equation 15

$$\mathbf{fGHG} = \left(\frac{\mathbf{1}}{\mathbf{n}} \times \sum_{\mathbf{t=1}}^{\mathbf{n}} \mathbf{fGHGt}\right) \times \mathbf{Tp} \times \mathbf{CF}$$

WHERE

fGHG	is the annual net GHG emissions (MT CO_2e)
fGHGt	is the rate of GHG emissions from the Project area at monitoring event (MT CO_2e per unit of time)
Tp	is the time period which corresponds to the annual period (yr)
n	is the number of monitoring events

t	is the monitoring event
CF	is the factor for converting from the measurement time scale to the time scale of Tp

4.1.3.3 HARVESTED GRAIN AND BIOMASS

This section describes methods for quantifying carbon removal from the Project area via harvested grain and biomass.

4.1.3.3.1 Introduction

The carbon in harvested grain and biomass represents an essential part of the carbon stock changes for Baseline agriculture and rice, or paludiculture Project conditions (Equation 12). Harvested grain or biomass is determined by 1) collection of grain or biomass in representative plots within the stratum; 2) determination of the carbon and moisture content on the collected material using literature and laboratory analysis of the material; and 3) estimation of total carbon removed in grain and/or biomass for the stratum. Alternatively, the Project Proponent may obtain information from the farmer about the weight of the harvested grain and/or biomass and use literature values and laboratory-determined values for the carbon and moisture content of the harvested grain and/or biomass to estimate the carbon dioxide harvested for the crop for the stratum (MT CO_2e) (Equation 16). The moisture content of the harvested material shall be determined at harvest. Methods described in Kalra (1997) and McGeehan and Naylor (1988) are applicable for determination of moisture content and carbon content.

4.1.3.3.2 Applicability

- Harvested grain and biomass shall be shown to adequately represent the hydrologic, water quality and soil conditions, and land and water management practices for the stratum.
- Annual estimates of harvested grain and biomass are sufficient. For multiple harvests (such as for hay or grain crops), the annual estimate shall equal the sum of all harvests.
- Monitoring must occur for Baseline establishment and renewal. For Project conditions, the monitoring frequency shall occur at least every 5 years over a period of 1 year.
- The Project Proponent shall demonstrate using maps and photographs that yield plots are representative of the entire stratum.

4.1.3.3.3 Quality Assurance and Quality Control

- Where yield plots are used, plots shall be replicated three times within each stratum and the entire plot shall be harvested.

- The average yield and standard deviation from the three replicate plots shall be used in uncertainty calculations in the Uncertainty Module (X-UNC).

4.1.3.3.4 Equations

For agricultural Baseline conditions and rice Project conditions, carbon removal in harvested grain and biomass shall be estimated using the following equation (Hollinger et al. 2005):

Equation 16

$$C_{gr} = W \times fC \times Y$$

WHERE

C_{gr}	is the carbon removal in harvested grain and biomass from the Project area (MT CO_2e)
W	is the moisture content expressed as a fraction
fC	is the fraction of carbon in the grain or biomass (Conner and Loomis, 1992)
Y	is the yield for the Project area (MT CO_2e)

The use of Equation 12 and Equation 16 assumes that 100% of the harvested biomass is eventually consumed and oxidized to CO_2 and CH_4 which is released back into the atmosphere.

4.1.3.4 AQUEOUS CARBON LOADS

This section describes quantification of carbon losses and gains at the Project site via aqueous carbon loads.

4.1.3.4.1 Introduction

For Baseline and Project conditions, aqueous carbon loads represent part of the overall carbon budget not explicitly determined by eddy covariance or chambers (Equation 12). Aqueous carbon can enter and exit the Project area to and from adjacent channels as dissolved and particulate organic carbon. The total organic carbon (TOC) concentration is equal to the sum of particulate and dissolved organic carbon. Loads are equal to the net water flow times the concentration of total organic carbon in the water. The Project Proponent shall measure concentrations, flow, and loads at the main inlet and outlet of water in Project areas and use methods

published in the peer-reviewed literature for determining concentrations, flow, and loads in tidal (Ganju et al. 2005; Bergamaschi et al. 2011) and non-tidal (Deverel et al. 2007) systems. For flow measurements, methods include manual flow and acoustic velocity meters. Methods for total dissolved organic carbon determination in drain-water samples are described in Deverel et al. (2007). Water management practices that limit drainage from managed wetlands substantially limit aqueous carbon exports.

Specifically, for non-tidal managed wetlands, subsurface and surface drainage flow shall be measured and calculated continuously using traditional flow measurements using manually operated flow meters and tracking stage at a control device such as a weir with a water level recorder. Alternatively, flows can be measured using continuous recording acoustic Doppler technology. For tidal systems, a similar approach can be used except that flow is bidirectional depending on tidal influences.

4.1.3.4.2 Applicability

- The determination of aqueous carbon loads shall be shown to adequately represent the hydrologic, water quality and soil conditions, and land and water management practices for the stratum.
- Measurements shall adequately represent the temporal variability in concentrations and loads.
- For non-tidal systems, the temporal variability is determined by hydrologic management and season variability. Monthly measurements are generally sufficient to characterize the temporal variability.
- Tidal fluxes of dissolved and particulate organic carbon shall be estimated or measured at intervals that adequately represent temporal variability, as determined by a sensitivity analysis made using the Uncertainty Module.

4.1.3.4.3 Quality Assurance and Quality Control

The uncertainty in manual flow measurements shall be determined as per the guidance in Sauer and Meyer (1992) and incorporated into the uncertainty equations in the Uncertainty Module (X-UNC). Uncertainty in acoustic velocity measurements shall be evaluated using information described in Laenen and Curtis (1989). Analytical uncertainty for dissolved organic carbon shall be determined using field duplicate and blank samples and laboratory QA/QC samples, and shall be incorporated into the flow measurement uncertainty.

4.1.3.4.4 Equations

The annual net aqueous loss of dissolved and particulate organic carbon (E_{aq}, in Equation 12) can be calculated by subtracting the aqueous carbon input from the aqueous carbon export. Specifically,

Equation 17

$$E_{aq} = (Q_{export} \times [TOC] - Q_{import} \times [TOC])$$

WHERE

Q_{export}	water flow exiting the Project area
Q_{import}	water flow entering the Project area
$[TOC]$	is the total organic carbon concentration, sum of particulate and dissolved organic carbon

Allochthonous carbon may enter a Project area from an outside source and may contribute to carbon accumulation at the site. However, it represents carbon assimilated by other sinks and the wetland Project area does not contribute to its removal from the atmosphere. For this reason, after it is quantified (as described in Equation 12), if a project area receives an input of allochthonous carbon, it should be deducted from the total carbon stock change of the Project area. For purposes of this methodology, carbon accumulation from outside sources may be excluded in determination of Baseline or Project GHG emissions or removals if not significant as per guidance of tool T-SIG. Allochthonous carbon accumulation in the Baseline may be conservatively set to zero, as its exclusion from the balance between GHG losses and gains would underestimate total GHG emission reductions. In the Project Scenario, net accumulation of allochthonous carbon must be subtracted from the net carbon balance of a wetland unless the Project Proponent can document that no other entity may claim its GHG emission reductions or removals (i.e., that no other entity may make an ownership claim to the emission reductions or removals for which credits are sought) and if its storage in the tidal wetland decreases the rate of its decomposition compared to what it would be in the absence of the Project (i.e., the case the tidal wetland was not implemented). In the Baseline Scenario, net accumulation of allochthonous carbon must be accounted for and subtracted from the baseline total carbon stock change, or can be conservatively set to zero.

4.1.3.5 SUBSIDENCE MEASUREMENTS

This section describes methods and techniques for subsidence measurements.

4.1.3.5.1 Introduction

For purpose of this methodology, subsidence is caused by the oxidation of organic soils (Deverel and Leighton 2010). As organic soils are drained for agricultural use and exposed to

oxygen, they oxidize and disappear. Subsidence is estimated as the difference between elevations at two points in time. Subsidence measurements, when the soil carbon pool includes biomass and dead organic matter of non-woody annual vegetation, can represent the ecosystem carbon stock changes. For example, Couwenberg et al. (2013) described a simple approach to determining total ecosystem net carbon loss from subsidence records.

If subsidence measurements are used, it is assumed that the soil carbon pool includes all ecosystem carbon pools. Where there are elevation measurements in organic or highly organic mineral soils at two or more points in time, the difference in elevation and soil carbon density can be used to estimate historic Baseline emissions by multiplying the elevation change by the soil carbon density. Soil carbon density is equal to the soil carbon content multiplied by the soil bulk density. Data for soil organic matter content for Delta and San Francisco Bay Estuary soils is described in Callaway et al. (2012), Deverel and Leighton (2010), and Drexler et al. (2009). Soil carbon content is generally equal to 50% of the soil organic matter content. Drexler et al. (2009) provided data for soil bulk density for eight Delta islands. Caution should be exercised and uncertainty quantified when using the relations of bulk density and organic matter and carbon and organic matter where they have not been verified using Project data.

4.1.3.5.2 Applicability

- The number of measurements shall be determined by strata, known spatial variability, and the required level of certainty as per the guidance in the T-PLOT tool. The determination of subsidence shall be shown to adequately represent the hydrologic, water quality and soil conditions, and land and water management practices for the stratum.
- Project Proponents shall be conservative in estimating the depth of subsidence from elevation measurement differences by calculating the minimum possible difference between elevations measured at two points in time.
- All elevation measurements for subsidence calculations shall be referenced to stable benchmarks.
- Project Proponents shall ensure and document the consistent use of vertical datums for elevations measured during different years.
- Project Proponents shall use conservative values for soil organic carbon and bulk density values that result in conservative estimates for subsidence.

4.1.3.5.3 Quality Assurance and Quality Control

Uncertainty in subsidence estimates stem from 1) elevation measurements; and 2) soil carbon and bulk density determinations. For elevation measurements, uncertainty is dependent on methods used that shall be documented and incorporated into uncertainty calculations in the Uncertainty Module (X-UNC). For example, Deverel and Leighton determined elevations at locations on Bacon Island in 2006 where elevations were measured by University of California researchers in 1978. The vertical closure error (the amount by which an elevation determined

by a series of elevation measurements fails to agree with an established elevation) for the 1978 survey with traditional surveying equipment was 0.07 meters (m). For the 2006 survey, which utilized real-time kinematic, static, and fast-static Global Positioning System measurements, vertical closure error was 0.002 m. Therefore, the conservatively estimated subsidence at any point along the survey route followed in 1978 and 2006 is equal to the elevation determined in 1978 minus the closure error, minus the sum of 2006 elevation and the closure error. Table 27 shows an example calculation. Elevation errors in topographic-map elevations range from about 0.3 to 1 m.

Table 27: Example Subsidence Calculation for Point 44027 on Figure 2 in Deverel and Leighton

YEAR	ELEVATION (M)	CLOSURE ERROR (M)	DEPTH OF SUBSIDENCE (M)
1978	-3.98	0.07	No subsidence – Time series begins
2006	-5.26	0.002	1.21 ((-3.98 – 0.07) - (-5.26+0.002))

Data presented in Drexler et al. (2009) provide ranges of estimates for organic matter content and bulk density for eight Delta islands.

4.1.3.5.4 Equations

When the cumulative net Baseline carbon stock changes and GHG emissions for the Project area can be estimated by changes in the soil carbon pools using the depth of subsidence, the following equation can be used:

Equation 18

$$\Delta C_{BSL} = \frac{44}{12} \times \sum_{i=1}^{n} (S_i \times BD_i \times fC_i \times A_i)$$

WHERE

S	is the depth of land subsidence (m)
BD	is the dry bulk density of the organic soil (t m^{-3})
fC	is the fraction of carbon in the organic soil on a dry weight basis

44/12	is the ratio of molecular weights of CO_2 to carbon (dimensionless)
A	is the area of the stratum (m^2)
i	refers to the stratum within the Project boundary
n	is the number of strata within the Project boundary

4.1.3.6 SOIL CORING, SEDIMENT EROSION TABLES, AND SEDIMENT PINS

The following sections describe methods used for soil carbon determination via soil sampling.

4.1.3.6.1 Introduction

Carbon stock changes in the soil carbon pool in managed non-tidal wetlands and tidal wetlands can be measured in soil cores by determining the carbon accumulated above feldspar markers or sediment pins pounded into the ground to refusal (US Geological Survey 2012) placed at the start of Project activities. Sedimentation erosion tables (SET) can also be used to determine soil biomass accretion. Sediment pins are subject to greater uncertainty than sediment erosion tables. Sediment pins are generally applicable where the depths of accretion are greater than 10 to 20 cm. Localized scour around sediment pins can occur. Experience in the San Francisco Bay Estuary demonstrates that basing measurements on the broader sediment surface can provide the necessary accuracy. The material located above the feldspar marker or sediment pin/sediment interface or at the SET measurement plot shall be analyzed for total carbon or organic matter content and bulk density. Any compaction that occurs should be measured and accounted for. The change in carbon stocks in soil cores shall be determined by quantifying the carbon density above a marker horizon defined by a feldspar marker.

Feldspar markers should be placed at the start of the Project activity. Feldspar marker horizons are prepared by spreading a thin aqueous slurry (~1 cm) layer of feldspar clay on the wetland surface (Cahoon and Turner 1989). Soil carbon content can be determined using elemental analysis using a CHN analyzer (Nelson and Sommers 1982) or estimated from the loss-on-ignition method (LOI) (Ball 1964). Results throughout the Sacramento-San Joaquin Delta and San Francisco Bay Estuary (Drexler et al. 2009; Callaway et al. 2012; Craft et al. 1991) demonstrate a statistically significant relation between soil carbon content and LOI. These regression relations can be used to calculate the carbon content of the harvested cores on a mass carbon per mass of soil basis. A weak regression would generate high uncertainty in the estimate. As for any variable included in the protocol, Project Proponents should strike a balance between the reduction of the Emission Reduction Tons (ERT) caused by elevated uncertainty and the costs needed to reduce such uncertainty.

To estimate carbon density in mass per unit volume, multiply the carbon content and the bulk density. The bulk density shall be determined using methods reported in Calloway et al. (2012) and Blake (1965).

Specific steps for core collection:

Step 1 Collect soil core samples and measure the depth of the feldspar marker or measure the sediment accumulated at the sediment pin, and collect a soil core sample to the depth of accumulated sediment. See the Quality Assurance section below for discussion of compaction and compaction avoidance.

Step 2 Multiple samples collected at the same plot may be aggregated provided that the uncertainty and guidance for estimating the appropriate number of samples is documented.

Step 3 For bulk density analysis, a single core shall be collected next to the core collected for determination of soil carbon content. Soil samples need to be thoroughly dried until their weight no longer changes and then the weight of each section needs to be divided by the volume.

Step 4 The mass of carbon per unit volume is calculated as the product of the carbon concentration and bulk density.

Sedimentation erosion tables (SET) and rod sedimentation erosion tables (RSET) may be used to determine the accumulation of biomass with time in conjunction with coring and determination of the mass of carbon per unit volume of the accumulating material (Lynch 2015). Additional guidance for estimating carbon stock changes and GHG emissions for tidal wetlands and sea grasses is provided by Howard et al. (2014).

4.1.3.6.2 Applicability

The number of samples shall be determined by strata, known spatial variability, and the required level of certainty, as outlined in the T-PLOT tool. The determination of soil carbon stock changes shall be shown to adequately represent the hydrologic, water quality and soil conditions, and land and water management practices for the stratum.

4.1.3.6.3 Quality Assurance and Quality Control

The primary quality control/quality considerations are related to 1) accurate depth of the core; and 2) spatial variability. Compaction during core collection is estimated by measuring the difference in elevation inside and outside of the coring tube to the nearest millimeter. Example coring devices include McAuley (Bricker-Urso et al. 1989), Livingstone (Wright 1991), or Hargis

(Hargis and Twilley 1994) coring devices, which allow cores to be taken with minimal or no compaction. Strata and known spatial variability shall determine the number of samples and the required level of certainty as described in the T-PLOT tool.

If inorganic carbon is present in soil samples, there may be interference in the determination of soil organic carbon. Total inorganic carbon can be determined and subtracted from the organic carbon determination.

4.1.3.6.4 Equations

Soil coring is used to estimate soil carbon stock changes. To estimate the change in soil carbon (ΔCsoil) for the Project area during the reporting period (MT CO_2e)

Equation 19

$$\Delta C_{soil} = \frac{1}{N} \times \sum_{i=1}^{n} (D_i \times CD_i)$$

WHERE

D_i	is the depth of the soil accumulated above a feldspar marker
CD_i	is the carbon density of the soil accumulated above a feldspar marker (product of the soil carbon content on a weight basis and soil bulk density)
i	is the stratum within the Project boundary
N	is the number of cores collected with stratum

4.1.3.7 BIOMASS CARBON POOLS AND BIOGEOCHEMICAL MODEL INPUTS

When methods described in this section are used to determine carbon stock changes, the Project Proponents shall demonstrate that the estimated GHG removal by above- and below-ground biomass is not already included in the determination of the overall carbon stock change calculation.

Rates of carbon accumulation in above and below-ground biomass can be measured using:

- direct measurements (allometric determinations and harvesting)
- indirect methods (remote sensing and other techniques)

Litter decomposition can be estimated using:

- traditional litterbags
- isotopic analysis
- modeling

4.1.3.7.1 Estimating Above- and Below-Ground Biomass Using Allometric and Destructive Methods

The mean carbon stock in above- and below-ground biomass per unit area is estimated based on field measurements of the wetland plants in fixed area plots using allometric equations and destructive methods such as those described in Miller and Fujii (2010) and Howard et al. (2014) (Table 28). The number and size of plots shall ensure adequate representation of the area being measured by utilizing guidance provided in the T-PLOTS tool. The allometric method can be used to estimate above-ground biomass by using equations that express above-ground biomass as a function of plant height and diameter. For example, Miller and Fujii (2010) used extensive destructive biomass harvest to determine parameters in allometric equations for the predominant species (Typha and Schoenoplectus spp) in managed non-tidal wetlands in the Delta. The following table provides the equations from Miller and Fujii (2010).

Table 28: Allometric Equations for Above-Ground Biomass Estimates (in g Dry Weight m^{-2})

SPECIES	DESCRIPTION	EQUATION
Schoenoplectus acutus	Biomass weight using height and diameter	$\log_{10}$weight = (0.5028 x ln height) + (0.3471 x ln diameter) - 1.7654 r^2 = 0.924
Schoenoplectus acutus	Biomass weight using only height	$\log_{10}$weight = (0.7947 * ln height) - 3.2177 r^2 = 0.824
Typha species	Plant biomass weight using height, diameter and leaf number	$\log_{10}$weight = -2.188 + (0.601 x ln height) + (0.2128 x ln diameter) + (0.2721 x ln leaf number) - 0.484 r^2 = 0.9

Miller and Fujii reported root biomass measurements and root:shoot ratios ranging from 0.6 ± 0.2 to 1.7 ± 0.4 for Schoenoplectus acutus and 0.7 ± 0.1 to 1.0 ± 0.3 for Typha sp. Values varied seasonally and with water depth. Average values for both species were not significantly different; 0.9 ± 0.1 for Schoenoplectus acutus and 0.8 ± 0.1 for Typha sp. For the purposes of this methodology for constructed wetland activities where these species are present, these values are appropriate for multiplication times the above-ground biomass weight. Destructive methods such as those described in Miller and Fujii can also be used to determine root biomass.

Where there are trees, methods described in Howard et al. (2014) can be used to estimate carbon stocks.

4.1.3.7.2 Estimating Biomass Using Remote Sensing Methods

Spectral information from remotely sensed imagery can be used to estimate above-ground biomass accumulating during the year. This spectral information can be used to not only estimate above-ground biomass, but also the fraction of photosynthetically active material driving photosynthesis, as well as the timing and duration of the growing season. This information can used as input for the biogeochemical model for wetlands described below.

PHENOCAM. Phenocams are digital cameras that are automated to record images of canopy cover throughout the year. These images can then be processed to calculate a greenness index (GI) that can be empirically related to above-ground leaf area index (LAI) based on field measurements, where LAI is defined as half the total developed area of green leaves per unit ground surface area. LAI can be directly measured using destructive field sampling or measured using a LAI sensor such as the LAI-2200C Plant Canopy Analyzer (LI-COR, Lincoln, NE, USA) (Sonnentag et al. 2011). Measurements must be collected several times during the growing season. LAI is an input to biogeochemical models and can be used to estimate gross primary productivity for Project conditions (managed and tidal wetlands and rice).

SATELLITE IMAGES. Satellite-derived LAI products give information across large spatial scales (e.g., 1km for MODIS) with fairly high temporal resolution (e.g., 8–16 days for MODIS). The drawbacks to this method include poor small-scale resolution associated with high uncertainty at the field scale as well as data gaps associated with cloud cover (Garrigues et al. 2008). Satellite-derived LAI products are therefore ideal for projects encompassing large spatial scales (multiple square kilometers) and need to be supplemented with direct measurements. Additional guidance for use of remote sensing is provided in Howard et al. (2014).

Project Proponents should be aware that standing dead materials can persist in non-tidal marshes for multiple years, which can influence remotely sensed estimates of leaf-area indices and biomass as live shoot density decreases in areas with dense thatch.

4.1.3.7.3 Estimating Litter Decomposition

Litter decomposition represents a large term in the global carbon budget, playing a critical role in regulating soil carbon dynamics across multiple scales of space and time (Zhang et al. 2008). Determination of litter decomposition rates is used in biogeochemical models that estimate soil CO_2 emissions. Project Proponents shall avoid double-counting when using decomposition or accumulation of litter in Project GHG accounting and soil carbon stock changes or other flux measurements already account for these processes. To accurately predict litter carbon stock changes, litter decomposition rates (k) must be measured or estimated. Litterbags are the most widely used method for direct k calculations and have been used and replicated around the world for decades (Olson 1963) and can be used within this methodology. The analysis of natural abundances of ^{13}C isotopes (Silva et al. 2013), as well as labeling experiments with isotopically enriched litter (Qiao et al. 2014), are also effective ways to estimate litter carbon stock changes over time. Laboratory microcosm studies show large discrepancy in relation to field litterbag and isotopic studies and shall not be used. Modeled decomposition rates on the long-term inter-site decomposition experiment team (LIDET) (Bonan et al. 2013) can be used to provide conservative estimates of decomposition.

Predicting root decomposition at wetland sites is greatly improved by estimating decomposition rates of wetland roots separately from all other litter. The LIDET databases can be used to generate conservative root decomposition estimates. The same methods shall be employed to estimate k values under Baseline and Project conditions. If models are used, they shall be constrained by main drivers of decomposition, such as geographic factors (latitude and altitude), climatic factors (temperature, precipitation, evapotranspiration), and litter quality (C:N ratios, lignin content), and calibrated using data for the Project or demonstrably equivalent conditions.

4.2 (MODEL-W/RC) BIOGEOCHEMICAL MODELS

4.2.1 Scope

Biogeochemical models allow for the ex-ante and ex-post estimation of GHG removals and emissions.

To be used by the Project Proponents, models must meet the following requirements:

- Be documented in the peer-reviewed literature;
- Be validated in the Project area or similar sites using peer-reviewed or other quality controlled data (i.e., collected as part of a government soils inventory or experiment) for the soils and for the hydrologic and biogeochemical conditions in the proposed Project area;
- Be calibrated using peer-reviewed or other quality-controlled parameter appropriate to each identified stratum;

- Be able to effectively simulate carbon stock changes and GHG emissions for Baseline and Project conditions;
- For models that include litter, above- and below-ground biomass, and soil organic matter pools, be able to demonstrate that there is no double-counting of carbon pools and include consideration of conservativeness and significance testing;
- Be conservative in estimating GHG emission reductions.

For Project conditions, a validated process-based biogeochemical model, the Peatland Ecosystem Photosynthesis, Respiration, and Methane Transport model (PEPRMT, pronounced "peppermint," also referred to as LUE-DAMM [Oikawa et al. 2017]), can be used for ex-ante estimation of CO_2 and CH_4 exchange from wetlands in the Sacramento-San Joaquin Delta (see Appendix C).

For agricultural Baseline conditions in the Sacramento-San Joaquin Delta, the SUBCALC model (Deverel and Leighton 2010) may be used to estimate Baseline CO_2 emissions (see Appendix C).

Additional models have been used to predict elevation changes in coastal ecosystems. The WARMER model (Wetland Accretion Rate Model of Ecosystem Resilience (Swanson et al. 2014) is a 1-D model of elevation that incorporates both biological and physical processes of vertical marsh accretion. The MEM model (Marsh Equilibrium Model) was developed as a tool for forecasting the future lifespan of coastal wetlands in the face of sea level rise. It forecasts marsh productivity and relative elevation (http://129.252.139.114/model/marsh/mem.asp).

4.2.2 Applicability and Methodological Requirements

The following conditions must be met for this Module to be used:

- For Project areas that are converted to flooded conditions, separate model simulations must be run for Baseline and Project conditions.
- The participating wetlands shall be in areas where the models have been successfully calibrated.
- The model is applicable to fully vegetated wetlands or strata.
- Wetlands or strata with open water require separate validation.[7]
- Net aqueous loss of carbon must be included in the model, be insignificant, or be estimated using other methods (see Methods Module MM-W/RC and T-SIG tool).
- For each model run, appropriate input parameter files must be available to the verifier.

[7] Conditions 3 and 4 represent different conditions that may occur in the same wetland or stratum due to hydrologic conditions or the stage of development.

PARAMETERS

PARAMETER	SI UNIT	DESCRIPTION
ΔC_{BSL}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Baseline Scenario. This parameter feeds into Equation 1 in the Methodology Framework Module (MF-W/RC).
ΔC_{actual}	MT CO_2e	Cumulative total of carbon stock changes and GHG emissions for the Project Scenario. This parameter feeds into Equation 1 in the Methodology Framework Module (MF-W/RC).

4.2.3 Model Calibration and Validation

In order to use a biogeochemical model, it needs to be parameterized, calibrated and validated for a specific Scenario, Project type, and area. Project emissions of CO_2 and CH_4 and N_2O may be estimated using biogeochemical models, which must be run separately for each site, stratum, or cohort. The biogeochemical model must be parametrized and calibrated for each stratum of each scenario (BL-AG, BL-SW, BL-OP, PS-MW, PS-TW, PS-RC) and for the specific characteristics of vegetation, soil, climate, hydrology of the stratum. Biogeochemical models must be validated for each GHG gas, verification period and stratum. If a range of condition exists among strata, the model can be validated only in the most diverse and extreme strata (for example highest and lowest soil organic matter, vegetation cover etc.). Validation within project boundary is not required if it is shown that the biogeochemical model can reproduce GHG fluxes for the range of conditions existing in the region, and that the condition range includes specific conditions existing at each stratum/site (different soil types, climate, water depth and salinity, vegetation cover, vegetation types).

Model calibration,parameterization and validation should preferably use at least 2 years of ecosystem flux data of CO_2 and CH_4. Other model input variables will also need to be recorded during this time. Based on experience, 2 years is the minimum in order for sufficient data for both parameterization and validation (recommended 70% data used for parameterization and 30% for validation). Also, the model may be calibrated with monitoring data collected after Project commencement. If discontinuous data are collected and used for calibration, model uncertainty will likely be greater and need to be quantified as per guidance in the Uncertainty Module (X-UNC).

4.3 (E-FFC) METHODS TO ESTIMATE FOSSIL FUEL EMISSIONS

Project Proponents will employ the currently approved Methods Module for estimating GHG emissions fossil fuel combustion approved by ACR.[8]

The fossil fuel emissions Methods Module shall be used to estimate all Project emissions that include but are not limited to earth-moving, construction, and agricultural operations such as cultivation, planting, and harvesting.

Annual emission estimate (E_{FFC}) in the Module E-FFC are cumulated to obtain the total fossil fuel Emission $fEFF$ for the Project area during the reporting period (t = year):

Equation 20

$$\mathbf{fEFF} = \sum_{\mathbf{t=1}}^{\mathbf{40}} \mathbf{E_{FFC}}$$

A Wetland Project will typically include higher fossil fuel emissions for the initial phase of implementation of the project, and then lower (or zero) levels of fossil fuel emissions for the rest of the crediting period. The total $fEFF$ for the Crediting period can be divided by the number of years (40) to obtain an annualized emissions rate to use to calculate ERT for each verification period.

4.4 (X-UNC) METHODS FOR ESTIMATING UNCERTAINTY

4.4.1 Scope

This Module provides guidance for calculating uncertainty for estimation of emissions and GHG removals from wetland construction and restoration activities and rice cultivation activities.

[8] E-FFC-WR Module, Estimation of emissions from fossil fuel combustion, in the methodology "Restoration of Degraded Deltaic Wetlands of the Mississippi Delta."

4.4.2 Applicability

This Module is mandatory and provides guidance for the calculation of the following sources of uncertainty:

- Baseline and Project emissions
- Baseline and Project changes in carbon stocks

Where an uncertainty value is unknown, or cannot be accurately calculated, a Project Proponent can use an indisputably conservative value for carbon stock changes or GHG emissions, in which case an uncertainty of 0% may be used for this component.

4.4.3 Parameters

This Module provides procedures to determine uncertainties.

PARAMETER	DESCRIPTION
UNC	Total (Project and Baseline) uncertainty (%)
UNC_{BSL}	Percentage uncertainty of the combined carbon stocks and GHG fluxes for the Baseline Scenario
UNC_{P}	Percentage uncertainty of the combined carbon stocks and GHG fluxes for the Project Scenario

Either IPCC Guidelines for GHG inventories (Eggleston et al. 2006; Penman et al. 2003), expert judgment,[9] or estimates based on sound sampling design and statistical analysis shall provide the basis for uncertainty calculations. Uncertainties arising from the measurement of carbon pools changes and GHG fluxes shall always be quantified.

To calculate total Project Uncertainty, the following equation shall be applied:

Equation 21

$$\text{Total (Project and Baseline) UNC} = \sqrt{UNC_{BSL}{}^2 + UNC_{P}{}^2}$$

[9] Justification should be supplied for all values and parameters measured or derived from expert judgment.

WHERE

UNC	is the total (Project and Baseline) uncertainty (%)
UNC_{BSL}	is the Baseline uncertainty (%)
UNC_{P}	is the Project uncertainty (%)

The allowable uncertainty under this methodology is ±10% of the mean carbon stock change at the 90% confidence level. Where this precision level is met, no deduction shall result for uncertainty. Where uncertainty exceeds 10% of the mean carbon stock change, the deduction shall be equal to the amount that the uncertainty exceeds the allowable level, as indicated in the Methodology Framework Module (MF-W/RC).

4.4.4 Estimating Baseline Uncertainty

It is important that the process of Project planning consider uncertainty. A priori estimations of statistical power (Park 2010) can be used to ensure proper spatiotemporal replication (Silva et al. 2013) and determine procedures, such as stratification and allocation of resources to allow the number of measurement plots to reduce uncertainty. It is good practice to consider uncertainty at an early stage to identify the data sources with the highest risk to allow the opportunity to conduct further work to improve representativeness and optimize Project practices over time. Estimation of uncertainty for pools and emissions sources requires calculation of both the mean and the 90% confidence interval. In all cases, uncertainty should be expressed as percentage as the 90% confidence interval of the mean.

The uncertainty in the Baseline Scenario is defined as the square root of the summed errors in each of the carbon pools and GHG fluxes listed in the Baseline Modules for each stratum. For modeled results, the uncertainty in the input inventory data and model structural uncertainty shall be considered as discussed below. The total Baseline uncertainty in each pool or GHG flux can be weighted by the size of the pool or GHG flux and the contribution of each stratum, so that Projects may reasonably target a lower precision level for pools that comprise only a small proportion of the total stock as follows:

Equation 22

$$\mathbf{Uncertainty_{BSL,SS,i}} = \frac{\sqrt{(\mathbf{U_{BSL,SS1,i}} \times \mathbf{E_{BSL,SS1,i}})^2 + (\mathbf{U_{BSL,SS2,i}} \times \mathbf{E_{BSL,SS2,i}})^2 + \cdots + (\mathbf{U_{BSL,SSn,i}} \times \mathbf{E_{BSL,SSn,i}})^2}}{\mathbf{E_{BSL,SS1,i}} + \mathbf{E_{BSL,SS2,i}} + \cdots + \mathbf{E_{BSL,SSn,i}}}$$

WHERE

$Uncertainty_{BSL,SS,i}$	is the percentage uncertainty of the combined carbon stocks and GHG flux for the Baseline case in stratum **i** (%)
$U_{BSL,SS,i}$	is the percentage uncertainty of 1,2…n carbon stocks and GHG flux for the Baseline case in stratum **i**
$E_{BSL,SS,i}$	is the carbon stock/flux in stratum **i** (1,2…n represent different carbon pools and/or GHG sources) for the Baseline case (MT CO_2-e)
i	is the stratum within the Project boundary

The same concept can be applied to calculate the total Baseline UNC from the UNC of each stratum and weighting the UNC of each stratum by its area.

4.4.5 Estimating Project Uncertainty

As with Baseline uncertainty, it is important that the process of Project planning also consider uncertainty. Procedures including stratification and the allocation of sufficient number of samples can help minimize uncertainty. It is good practice to consider uncertainty at an early stage to identify the data sources with the highest risk to allow the opportunity to conduct further work to diminish uncertainty. In all cases, uncertainty should be expressed as a percentage as the 90% confidence interval of the mean. The uncertainty in the Project Scenario should be defined as the square root of the summed errors in each carbon pool or flux. For modeled results, follow guidelines discussed below. The errors in each pool or flux can be weighted by the size of the pool/flux and the area of each stratum so that Projects may reasonably target a lower precision level for pools or fluxes that comprise only a small proportion of the total stock as follows:

Equation 23

$$\mathbf{Uncertainty_{P,SS,i}} = \frac{\sqrt{(\mathbf{U_{P,SS1,i}} \times \mathbf{E_{P,SS1,i}})^2 + (\mathbf{U_{P,SS2,i}} \times \mathbf{E_{P,SS2,i}})^2 + \cdots + (\mathbf{U_{P,SSn,i}} \times \mathbf{E_{P,SSn,i}})^2}}{\mathbf{E_{P,SS1,i}} + \mathbf{E_{P,SS2,i}} + \cdots + \mathbf{E_{P,SSn,i}}}$$

WHERE

$Uncertainty_{P,SS,i}$	is the percentage uncertainty of the combined carbon stocks and GHG fluxes for the Project Scenario in stratum **i** (%)
$U_{P,SS,i}$	is the percentage uncertainty of each carbon stock and GHG flux for the Project Scenario in stratum **i** (%)

$E_{P,SS,i}$	is the Project carbon stock and GHG flux in stratum i (1,2…n represent different carbon pools and/or GHG sources)

The same concept can be applied to calculate the total Project UNC from the UNC of each stratum and weighting the UNC of each stratum by its area.

4.4.6 Estimating Uncertainty in Eddy Covariance Measurements

When calculating uncertainty associated with using eddy covariance to estimate emission reductions, this protocol requires Project Proponents to account for random measurement error and errors associated with gap-filling procedures used to calculate annual sums. Systematic bias error is also discussed here but can be conservatively excluded from uncertainty deductions if quality assurance and quality control measures are appropriately followed as discussed in the Measurement Module (MM-W/RC).

4.4.6.1 RANDOM MEASUREMENT ERROR

Random measurement error can create substantial noise or scatter in the data and can occur due to spectral filtering effects, turbulent transport, instrumentation, and footprint issues (Richardson et al. 2006). Errors can be reduced by using high sampling rates (at least 1Hz; ideally 10Hz), measuring continuously during each Project year, measuring gas concentration and wind speed high enough above the vegetation, minimizing separation between sensors (<20cm), and minimizing flow distortion in the sensor array and mast (Massman 2000).

Two general approaches are allowed for estimating the random error (ε_{random}). A Project Proponent may use a documented and validated empirical model demonstrated to be an accurate predictor of the observed eddy covariance data. The residual between observed and modeled fluxes can give an estimate of error as long as model error is shown to be minimal (Richardson and Hollinger 2005). The Project Proponent may also use a daily-differencing approach where data points collected under the same environmental conditions in successive days (x_1, x_2) are compared and the random measurement error is estimated as the standard deviation of the differences between x_1 and x_2 (Liu et al. 2009; Richardson et al. 2006). This method can be used in combination with Monte Carlo methods to estimate the 90% confidence interval due to random error in gap-filled net ecosystem exchange at the annual time step. It is important to note that random error associated with eddy covariance measurements typically follows a double-exponential (Laplace) distribution and not the normal (Gaussian) distribution; therefore, maximum likelihood estimation techniques should be used to estimate random error confi-

dence intervals as opposed to least squares optimization that requires normally distributed error and constant variance. Alternatively, the Project Proponent may also use peer-reviewed methods for estimating the random error in eddy covariance methods.

4.4.6.2 ESTIMATION OF RANDOM AND GAP FILLING ERROR OVER LONG TIME SCALES

To estimate uncertainty of annual sums for emissions and carbon stock changes associated with gap-filling using eddy covariance, Project Proponents shall use peer-reviewed methodologies. Monte Carlo or resampling techniques are recommended. System failure and data filtering can lead to gaps in the data that need to be filled in order to calculate annual sums. Most sites experience 35% data loss (Falge et al. 2001). If more than 70% of eddy covariance data need to be gap filled and uncertainty in measurements and annual sums are excessively high, an alternate measurement method for measuring emissions and carbon stock changes must be used. There are several approaches for filling data gaps (Moffat et al. 2007). Generally, the longer the time scale of integration, the smaller the uncertainty due to larger sample sizes and the dampening of outliers. Resampling techniques allow accounting for uncertainties associated with gap-filling.

Project Proponents may use the bootstrap resampling technique for estimating error associated with gap-filled annual sums ($\varepsilon_{gapfill}$) or other appropriate peer-reviewed method. For the bootstrap resampling technique, artificial datasets (of 1,000-10,000 data points) are created from the observed data using Monte Carlo techniques. Gaps are then filled in those data sets. These datasets are used to calculate annual values and the variation across annual values is used to estimate a 90% confidence interval around the annual carbon stock changes and GHG emissions (Hirano et al. 2012).

Random measurement error and gap-filling error are calculated using the root-sum-square method (Liu et al. 2009) and collectively constitute the total eddy covariance uncertainty expressed as a 90% confidence interval around the annual sum, U_{Ec}.

Equation 24

$$U_{EC} = \sqrt{\varepsilon_{random}{}^2 + \varepsilon_{gapfill}{}^2}$$

WHERE

U_{Ec}	is the total uncertainty for eddy covariance measurements
$\varepsilon_{gapfill}$	is the 90% confidence interval associated with gap-filled annual sums

ε_{random}	is the 90% confidence interval of the total random measurement uncertainty described above

4.4.6.3 SYSTEMATIC MEASUREMENT ERROR

Systematic measurement errors create a constant bias in the data. These errors do not need to be deducted from emission reductions using eddy covariance techniques if they are appropriately avoided or corrected for as per guidelines in the section 4.1, Measurement Methods (MM-W/RC). Systematic errors or biases in the data can be avoided by calibrating instruments properly and meeting assumptions of the eddy covariance technique such as requirements of flat homogeneous terrain and ample turbulence. These errors are also related to advection, drainage effects, storage (Aubinet et al. 2005), and roving flux footprints (Aubinet et al. 2005; Göckede et al. 2006). Previous work in the Delta has demonstrated flux footprint issues can create large errors in eddy flux measurements (Baldocchi et al. 2012). Other systematic biases can be avoided by correcting for high-frequency losses and density fluctuations associated with long tube lengths in closed path systems. For further discussion of systematic errors associated with eddy covariance measurements and how to avoid and correct for them, see Richardson et al. (2012) and the Measurement Module (MM-W/RC).

4.4.7 Estimating Uncertainty in Biogeochemical Models

When using process-based biogeochemical models to estimate emission reductions, this protocol requires Project Proponents to account for model structural error and error associated with data inputs. The uncertainty associated with model inputs and model structural uncertainty shall be incorporated into the total uncertainty.

4.4.7.1 ERROR ASSOCIATED WITH DATA INPUTS

Project Proponents shall estimate random measurement and sampling error associated with data inputs for biogeochemical models (Keenan et al. 2011; Richardson et al. 2010). Where measurements are replicated in time and space within strata, pools, and locations, sampling error can be calculated using the standard error of the mean value of the replicate measurements. For example, initial measurements of soil organic carbon must be replicated across strata. Those measurements will be averaged and the 90% confidence intervals of the mean is used to estimate the spatial uncertainty in soil organic carbon measurements. The estimated uncertainty shall be incorporated into the model uncertainty estimate.

To estimate random measurement error, measurements shall be replicated in the same location during the same timeframe. For example, if LAI is measured using a LAI-2200C Plant Canopy Analyzer (LI-COR, Lincoln, NE, USA), the variance across measurements replicated in the same location can be used to calculate the random error associated with LAI data. Random

measurement and sampling errors together comprise the total error associated with each data input. The percent error associated with data inputs (U_{inputs}) is estimated by taking the product of the random and sample errors. Errors are expressed as 90% confidence intervals.

Equation 25

$$U_{inputs} = \prod_{i} (\sigma_{random_i} + \sigma_{sample_i})$$

WHERE

σ_{random_i}	is the 90% confidence interval associated with measurements of model inputs in stratum i
σ_{sample_i}	is the 90% confidence interval associated with sample collection in stratum i

Meteorological drivers for the model, such as air temperature and available light, do not add significant error to the model estimations of emissions and therefore do not need to be accounted for in estimating emission reductions.

4.4.7.2 ERROR ASSOCIATED WITH MODEL STRUCTURAL UNCERTAINTY

Model structure uncertainty (U_{struct}) shall be estimated by validation of the model against data that are independent of the data used to calibrate the model. A minimum of 1 year of data will be used for estimates of uncertainty. There are numerous ways of estimating model output uncertainty, such as bootstrapping methods discussed above. In addition, a χ^2 statistic can be used to determine the uncertainty of the model output. Project Proponents shall document appropriate peer-reviewed methods and parameters for calculating model uncertainty. As new data and updated model versions become available, model structural uncertainty shall be re-evaluated.

Model uncertainty must be calculated for each year when the carbon stock changes and GHG emissions are estimated. Model-estimated uncertainty deductions to emission reductions shall be calculated as follows:

Equation 26

$$ER_{corr} = \sqrt{U_{inputs}^{\ 2} + U_{struct}^{\ 2}}$$

WHERE

ER_{corr}	is the total model uncertainty expressed as a 90% confidence interval around the annual sum (MT CO_2-e)
U_{inputs}	is the total uncertainty from model inputs expressed as a 90% confidence interval (MT CO_2-e)
U_{struct}	is the model structure uncertainty expressed as a 90% confidence interval (MT CO_2-e)

4.4.8 Parameter Tables

DATA/ PARAMETER	$E_{BSL,SS}$
DATA UNIT	MT CO_2-e
USED IN EQUATION	Equation 25
DESCRIPTION	Carbon stock and GHG fluxes (if determined significant) for the Baseline case
SOURCE OF DATA	The terms denoting significant carbon stocks or GHG emissions from Baseline Modules used to calculate emission reductions
MONITORING FREQUENCY	The monitoring must occur within 5 years before the start of the Project Activity and when the Baseline is revisited
COMMENT	Baseline stocks and GHG sources are estimated ex-ante for each Baseline period

DATA/ PARAMETER	$E_{P,SS}$
DATA UNIT	MT CO_2-e

USED IN EQUATION	Equation 26
DESCRIPTION	Carbon stock and GHG fluxes (if determined significant) for the Project case
SOURCE OF DATA	The terms denote significant carbon stocks or GHG fluxes used to calculate net emission reductions from the relevant Modules
MONITORING FREQUENCY	Monitoring frequency may range from 5 to 10 years and can be fixed to coincide with the reporting period
COMMENT	The ex-ante estimation shall be derived directly from the estimations originating in the relevant Modules.

DATA/ PARAMETER	$U_{BSL,SS}$
DATA UNIT	%
USED IN EQUATION	Equation 25
DESCRIPTION	Percentage uncertainty (expressed as 90% confidence interval as a percentage of the mean where appropriate) for carbon stocks and GHG sources in the Baseline case in stratum i
SOURCE OF DATA	Calculations arising from field measurement data.
MONITORING FREQUENCY	The monitoring must occur within five years before the start of the Project Activity and when the Baseline is revisited.
COMMENT	Baseline stocks and sources are estimated ex-ante for each Baseline period. Uncertainty in pools derived from field measurement with 90% confidence interval calculated as the standard error of the averaged plot measurements in each stratum multiplied by the t value for the 90% confidence level. For emission sources and wetland loss, conservative parameters should be used to allow the uncertainty to be set as zero.

DATA/ PARAMETER	$U_{P,SS}$
DATA UNIT	%
USED IN EQUATION	Equation 26
DESCRIPTION	Percentage uncertainty (expressed as 90% confidence interval as a percentage of the mean where appropriate) for carbon stocks and GHG sources in the Project case
SOURCE OF DATA	Calculations arising from field measurement data
MONITORING FREQUENCY	Monitoring frequency may range from 5 to 10 years and can be fixed to coincide with the reporting period
COMMENT	Uncertainty in pools derived from field measurement with 90% confidence interval calculated as the standard error of the averaged plot measurements in each stratum multiplied by the t value for the 90% confidence level. For emission sources and wetland loss conservative parameters should be used to allow the uncertainty to be set as zero.

4.5 (T-RISK) TOOL FOR ESTIMATING PERMANENCE AND RISK

The Project will employ the non-permanence risk tool currently approved by ACR as referenced in the ACR Standard.

4.6 (T-SIG) TOOL FOR SIGNIFICANCE TESTING

The currently acceptable significance testing tool is the Clean Development Mechanism (CDM) tool for testing significance of GHG emissions, which can be found at:

http://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-04-v1.pdf/history_view

4.7 (T-PLOT) TOOL FOR DESIGNING A FIELD SAMPLING PLAN FOR PLOTS

The currently acceptable tool is the Clean Development Mechanism (CDM) tool for calculation of the number of sample plots for measurements, which can be found at:

http://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-03-v2.1.0.pdf/history_view

DEFINITIONS

If not explicitly defined here, the current definitions in the most recent version of the American Carbon Registry (ACR) Standard apply.

Baseline	Most likely management scenario in the absence of the Project
Ex-ante	"Before the event" or predicted response of Project activity
Ex-post	"After the event" or measured response of Project activity
Historical Reference Period	The historical period prior to the Project start date that serves as the source of data for defining the Baseline
i	Subscript used to represent a stratum
Leakage	Leakage refers to a decrease in sequestration or increase in emissions outside project boundaries as a result of project implementation. Leakage may be caused by shifting of the activities of people present in the project area, or by market effects whereby emission reductions are countered by emissions created by shifts in supply of and demand for the products and services affected by the project.
Module	Component of a methodology that can be applied on its own to perform a specific task
Offset	Reduction in emissions of GHG made in order to compensate for or to offset an emission made elsewhere
Open Water	Inundated coastal areas where there are areas of 10% or less emergent vegetation
Permanently Flooded Wetlands	Areas that are inundated during the entire year and in which there is wetland vegetation. Water levels range from land surface to 1 m above land surface.
Project Proponent	An individual or entity that undertakes, develops, and/or owns a project. This may include the project investor, designer, and/or owner of the lands/facilities on which project activities are conducted. The Project Proponent and

	landowner/facility owner may be different entities. The Project Proponent is the ACR account holder.
Stratification	A standard statistical procedure to decrease overall variability of carbon stock estimates by grouping data taken from environments with similar characteristics (e.g., vegetation type, age class, hydrology, elevation)
Seasonal Wetlands	Seasonally flooded areas containing wetland vegetation that are drained during at least 5 consecutive months during the spring and summer.
Tidal Wetlands	Wetlands affected by the cyclic changes in water levels caused by the tidal cycle. They are closely linked to estuaries where sea water mixes with fresh water to form an environment of varying salinities.
Tool	Guideline or procedure for performing an analysis (e.g., tool for testing significance of GHG emissions in A/R CDM Project activities) or to help use or select a module or methodology.

APPENDIX A: GLOBAL WARMING POTENTIAL LEAKAGE EVALUATION FOR REPLACEMENT OF TRADITIONAL AGRICULTURE BY WETLANDS AND RICE IN THE SACRAMENTO-SAN JOAQUIN DELTA

A.1 INTRODUCTION AND BACKGROUND

Leakage is an increase in the global warming potential (GWP) (i.e., changes in greenhouse emissions [GHG] or removals) outside the Project boundaries that occurs because of the Project action. The American Carbon Registry (ACR) requires Project Proponents to assess, account for, and mitigate for leakage above de-minimis levels. Project Proponents must deduct leakage that reduces the GWP benefit of a Project in excess of the applicable threshold specified in the methodology.

Activity-shifting leakage occurs when the land uses resulting in baseline emissions that operated in the Project area before the Project start date are relocated to another area outside of the Project boundary. Such market-effects leakage is transmitted through market forces: a supply reduction can result in an upward pressure on price that may incentivize increased production and shifts in cropping patterns elsewhere. The change in the GWP as the result of these market-effects leakage shall be accounted for in the net Project GHG removals. For the activities included in this methodology, the market-effects leakage would result from replacement of crops currently grown in the Sacramento-San Joaquin Delta (Delta) by wetlands and rice.

An analysis is presented of leakage for replacement of traditional crops in the Delta with wetlands and rice. First, an economic analysis was conducted to determine how crop acreages statewide would be affected by Delta land conversion. Next we estimated the change in GWP as the result of this crop-area change.

A.2 METHODOLOGY

A.2.1 Economic Analysis

ERA Economics (see ERA technical memorandum below) used the Statewide Agricultural Production (SWAP) model[10] to quantify market leakage. The purpose of this analysis was to evaluate the potential "leakage" effects for four Delta land-use-change scenarios. For the purposes of this analysis, market leakage is defined as the shift in agricultural production to other regions of California as a result of land changes in the Delta. Land use change from traditional crops to wetlands and rice in the model has been imposed as an exogenous policy constraint in the model.

The SWAP model is a regional agricultural production and economic optimization model that simulates decisions by farmers across 93 percent of agricultural land in California (over 6 million acres). It is the most current in a series of California agricultural production models originally developed by researchers at the University of California at Davis in collaboration with the California Department of Water Resources. The SWAP model and its predecessor, the Central Valley Production Model (CVPM), have been used for numerous policy analyses and impact studies over the past 15 years, including the economic implications of Delta conveyance options[11] and has been subject to peer review.

For this analysis, the 27 Central Valley SWAP model regions were aggregated into 4 regions: Sacramento Valley, Delta, San Joaquin River, and Tulare Lake Basin. Additional SWAP model regions along the central coast and southern California were not included in the analysis because these regions are decoupled from the Central Valley market. The 20 standard crop groups modeled in SWAP were aggregated into 7 groups: trees and vineyards; irrigated pasture; rice; miscellaneous field crops including corn; forage and other field crops; vegetables; and cotton.

The SWAP model was used to estimate crop acreage changes for the following alternatives in which land-use changes were simulated to occur by 2030: conversion of traditional field crops and pasture to wetlands or rice. There is no option for implementing wetlands in the SWAP model so it was assumed that fallow land would adequately represent wetlands. Field crops and pasture predominate in areas where there are oxidizing organic soils that contribute to baseline carbon dioxide emissions.

[10] R. E. Howitt, J. Medellin-Azuara, D. MacEwan, and J. R. Lund. (2012). Calibrating disaggregate economic models of agricultural production and water management. *Environmental Modeling and Software 38*, 244-258.

[11] D. MacEwan and S. Hatchett. (2012). Statewide Agricultural Production Model Update and Application to Federal Feasibility Analysis. Prepared for United States Department of the Interior, Bureau of Reclamation Mid-Pacific Region. 104 pp.

- No Action Alternative (NAA).
- Remove 35,000 acres of field crops from the Delta and leave the land fallow.
- Remove 35,000 acres of field crops from the Delta and convert those acres to rice.
- Remove 10,000 acres of irrigated pasture from the Delta and leave the land fallow.
- Remove 10,000 acres of irrigated pasture from the Delta and convert those acres to rice.

A.2.2 Calculation of Changes in Greenhouse Gas Emissions and Removals

To estimate GWP changes, we used the results of statewide modeling and field experiments for over 40 crops.[12] We aggregated the GWP into the 7 groups used in the SWAP analysis and estimated GWP on a per acre basis. We used the estimated GWP in tons of carbon dioxide per acre per year multiplied times the non-Delta acreage changes for the crop groups to estimate the potential GWP leakage for each scenario. Table 29 shows the net emissions (positive values) and removals (negative values) and associated standard error for the crop groups.

Table 29: Greenhouse Gas Emissions (+) and Removals (-) for Crop Groups

CROP GROUP	TONS CARBON DIOXIDE EQUIVALENTS PER ACRE PER YEAR	STANDARD ERROR
Trees and vines	-0.7	0.05
Pasture	0.2	4.1
Rice	4.8	3.9
Field crops (corn, safflower, sorghum, sunflower)	-2.4	0.2
Miscellaneous field crops (small grains, dry beans, alfalfa, hay)	-4.2	0.3
Vegetable crops	1.9	0.2

[12] C. Li, J. Six, W. R. Horwath, and W. Salas. (2014). Calibrating, Validating, and Implementing Process Models for California Agriculture Greenhouse Gas Emissions, Final Report to the Air Resources Board. February 27, 2014.

CROP GROUP	TONS CARBON DIOXIDE EQUIVALENTS PER ACRE PER YEAR	STANDARD ERROR
Cotton	2.8	3.7

A.3 RESULTS AND DISCUSSION

A.3.1 Economic Analysis

A.3.1.1 NO ACTION ALTERNATIVE

The 2030 No Action Alternative provides the baseline against which alternative simulations were compared. Table 30 shows the land use by region and crop group.

Table 30: No Action Alternative (2030) Land Use, Thousands of Acres

REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
SACRA-MENTO	611	73	575	124	203	142	2
DELTA	48	10	5	152	97	54	0
SAN JOAQUIN	603	25	11	382	192	202	60
TULARE	1,280	23	0	561	533	353	205
TOTAL	2,541	131	590	1,219	1,026	752	268

A.3.1.2 ALTERNATIVES

The predominant crops in the Central Delta where wetlands and rice would likely be implemented to mitigate subsidence and provide a greenhouse removal benefit are field crops (primarily corn) and pasture. Thus, the alternative simulations replaced these crops with wetlands and rice. Table 32 shows the statewide acreage changes for the alternatives.

RETIRE 35,000 ACRES FIELD CROPS AND CONVERT TO WETLANDS

In alternative 2, 35,000 acres of field crops (corn, safflower, and "other field crops") are converted to wetlands. The statewide change in the total agricultural footprint is slightly less than 35,000 acres, indicating limited crop substitution to other regions as farmers adjust crop mix in response to changing relative prices. Most of the acreage change occurs in the Delta.

RETIRE 35,000 ACRES FIELD CROPS AND CONVERT TO RICE

Alternative 3 is the same as alternative 2 except the 35,000 acres are converted entirely to rice. The estimated statewide decrease in the total agricultural footprint is estimated to be less than 20,000 acres. There is a simulated decrease in rice acreage in the Sacramento Valley, the primary rice-producing area in the state.

RETIRE 10,000 ACRES IRRIGATED PASTURE AND CONVERT TO WETLANDS

In alternative 4, 10,000 acres of pasture are removed from the Delta and that land is converted to wetlands. Statewide, net acreage changed by approximately the same amount.

RETIRE 10,000 ACRES IRRIGATED PASTURE AND CONVERT TO RICE

Alternative 5 is the same as alternative 4 except the pasture acreage is converted entirely to rice. The estimated statewide change in the total agricultural footprint is estimated to be less than 1,000 acres. The primary land use change would occur in the Delta where rice replaces pasture. Some acreage is simulated to go out of rice production in the Sacramento Valley.

Table 31: Acreage Changes by Region and Crop Group for Alternatives Relative to the NAA

SCENARIO	REGION	TREES AND VINES	PAS-TURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGE-TABLES	COT-TON
A2 FIELD CROPS TO WET-LANDS	SACRA-MENTO	-9	-178	-5	920	-247	-49	-1
	DELTA	-522	5,119	6	-35,992	-2,948	-662	0
	SAN JOAQUIN	-106	-72	-2	853	-359	-51	-45
	TULARE	-101	-498	0	1,422	-384	-36	-96
A2 TOTAL NET CHANGE	**-34,043**	**-738**	**4371**	**-1**	**-32,797**	**-3,938**	**-798**	**-142**
A3 FIELD CROPS TO RICE	SACRA-MENTO	2,414	557	-2,919	914	583	124	55
	DELTA	-257	-10,071	35,000	-35,000	-11,029	-449	0
	SAN JOAQUIN	-447	-59	-111	630	133	-53	-49
	TULARE	-276	-364	0	664	172	-66	-201
A3 TOTAL NET CHANGE	**-20,105**	**1,434**	**-9,937**	**31,970**	**-32,792**	**-10,141**	**-444**	**-195**
A4 PASTURE TO WET-LANDS	SACRA-MENTO	-11	110	11	14	-77	-2	0
	DELTA	-54	-10,000	71	-1,768	1,732	19	0
	SAN JOAQUIN	31	60	3	79	-118	-1	1
	TULARE	24	114	0	62	-148	10	42

SCENARIO	REGION	TREES AND VINES	PAS-TURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGE-TABLES	COT-TON
TOTAL NET CHANGE		-9,796	-10	-9,716	85	-1,613	1,389	26	43
A5 PAS-TURE TO RICE	SACRA-MENTO	883	298	-936	-11	186	56	18
	DELTA	4	-10,000	10,000	60	378	11	0
	SAN JOAQUIN	-73	48	-26	52	12	1	-1
	TULARE	-33	78	0	-23	1	2	3
TOTAL NET CHANGE		988	781	-9,576	9,038	78	577	70	20

A.3.2 Greenhouse Gas Analysis Results

A.3.2.1 ALTERNATIVES

RETIRE 35,000 ACRES OF FIELD CROPS AND CONVERT TO WETLANDS

We estimated the GHG effect of changes in crop acreage outside the Delta on the GWP (Table 33). Due to simulated changes in price, supply, and demand, the SWAP model estimated a total change of 5,431 acres for the non-Delta region. For each crop group, the change in acreage was multiplied by the emissions or removals listed in Table 30 to result in a net removal of 4,198 tons carbon dioxide equivalents per year relative to the NAA (Table 33). For comparison, estimated median baseline emissions in the Delta are about 7 tons carbon dioxide equivalents per acre per year[13] due to the oxidation of organic soils. Therefore, for the 35,000 acres of field crops in the Delta, the estimated baseline emission is about 245,000 tons carbon dioxide equivalents per year. The estimated standard error associated with the GWP is relatively large

[13] S. J. Deverel and D. A. Leighton. (2010). Historic, recent, and future subsidence, Sacramento-San Joaquin Delta, California, USA. *San Francisco Estuary and Watershed Science 8*(2). http://www.escholarship.org/uc/item/7xd4x0xw.

as there is substantial variability within crop groups and spatial and temporal variability associated with the modeled and measured values. Considering the total standard error (the sum of absolute values for individual crop groups) results in a range of GWP change relative to the NAA of -8,790 to 395 tons carbon dioxide equivalents per year.

Table 32: Change in Acreage and Greenhouse Gas Emissions Due to Conversion to Wetlands in Alternative 2

	TREES AND VINES	PAS-TURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETA-BLES	COT-TON	TOTAL
Non-Delta acreage change	-215	-748	-7	3,195	-990	-135	-141	5,431
Non-Delta GWP change (tons carbon dioxide equivalents per year)	151	-150	-35	-7,667	4,156	-257	-396	-4,198
Estimated GWP Stand-ard Error	11	3,067	29	639	297	27	524	4,593

RETIRE 35,000 ACRES OF FIELD CROPS AND CONVERT TO RICE

For this alternative, the SWAP model estimated a total non-Delta acreage change of 8,152 acres (Table 34). For each crop group, the change in acreage was multiplied by the emissions or removals listed in Table 30 to result in a net GWP change of -25,270 tons carbon dioxide equivalents per year relative to the NAA. A key reason for the large net removal is the decrease in non-Delta rice acreage, which was multiplied by the estimated per acre emissions of 4.8 tons carbon dioxide equivalents per acre per year on mineral soils in California (Table 30). Similar to Alternative 2 and for comparison, the estimated baseline emission for the 35,000 acres of field crops in the Delta is about 245,000 tons carbon dioxide equivalents per year. Considering the total standard error (the sum of absolute values for individual crop groups) results in a range of GWP change relative to the NAA of -39,156 to -11,383 tons carbon dioxide equivalents per year.

Table 33: Change in Acreage and GWP Due to Conversion to Rice in Alternative 3

	TREES AND VINES	PAS-TURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGE-TABLES	COT-TON	TOTAL
Non-Delta acreage change	1,691	134	-3,031	2,208	888	5	-195	8,152
Non-Delta GWP change (tons carbon dioxide equivalents)	-1,183	27	-14,547	-5,299	-3,730	10	-547	-25,270
Estimated GWP Standard Error	85	551	11,819	442	266	1	723	13,886

RETIRE 10,000 ACRES OF PASTURE AND CONVERT TO WETLANDS

For this alternative, the SWAP model estimated a total non-Delta acreage change of 1,269 acres. For each crop group, the change in acreage was multiplied by the emissions or removals listed in Table 30 to result in a net GWP change of 1,296 tons carbon dioxide equivalents per year relative to the NAA (Table 35). For comparison, estimated median baseline emissions in the Delta are about 7 tons carbon dioxide equivalents per acre per year. Therefore, for the 10,000 acres of pasture in the Delta, the estimated baseline emission is about 70,000 tons carbon dioxide equivalents per year. The estimated change in the GWP is less than 2% of the estimated baseline emission. Considering the total standard error (the sum of absolute values for individual crop groups), results in a range of GWP change relative to the NAA of -221 to 2,813 tons carbon dioxide equivalents per year or a maximum of 4% of baseline emissions.

Table 34: Change in Acreage and Annual Greenhouse Gas Emissions Due to Conversion to Wetlands in Alternative 4

	TREES AND VINES	PAS-TURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGE-TABLES	COT-TON	TOTAL
Non-Delta acreage change	43	284	14	155	-343	6	43	890
Non-Delta GWP change (tons carbon dioxide equivalents)	-30	57	69	-373	1,441	12	121	1,296
Estimated GWP Standard Error	2	1,164	56	31	103	1	160	1,517

RETIRE 10,000 ACRES OF PASTURE AND CONVERT TO RICE

For this alternative, the SWAP model estimated a total non-Delta acreage change of 2,460 acres. For each crop group, the change in acreage was multiplied by the emissions or removals listed in Table 30 to result in a net GWP change of -5,788 tons carbon dioxide equivalents per year relative to the NAA. The decrease in rice acreage outside the Delta represents the majority of the change in the GWP. Similar to Alternative 4 and for comparison, the estimated baseline emission for the 10,000 acres of pasture in the Delta is about 70,000 tons carbon dioxide equivalents per year. Considering the total standard error (the sum of absolute values for individual crop groups) results in a range of GWP change relative to the NAA of -11,465 to -111 tons carbon dioxide equivalents per year.

Table 35: Change in Acreage and Annual Greenhouse Gas Emissions Due to Conversion to Wetlands in Alternative 5

	TREES AND VINES	PAS-TURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGE-TABLES	COT-TON	TOTAL
Non-Delta acreage change	777	424	-962	18	199	60	20	2,460
Non-Delta GWP change (tons carbon dioxide equivalents)	-544	85	-4,619	-44	-835	114	55	-5,788
Estimated GWP Standard Error	39	1,737	3,753	4	60	12	73	5,677

A.4 SUMMARY AND CONCLUSIONS

Holistic economic and GWP analysis of likely land use changes in California due to implementation of rice and wetlands in the Delta provides useful and insightful information about potential market-based leakage. For four alternatives in which we simulated the changes in agricultural acreages resultant from conversion of traditional crops to wetlands and rice in the Delta, estimated GWP changes were insignificant relative to the no-action alternative and baseline emissions or there was a net GWP benefit. The following bullets summarize our results:

- Retirement of 35,000 acres of field crops and conversion to wetlands resulted in a non-Delta GWP change of -4,198 tons carbon dioxide equivalents per year. The baseline emissions associated with field crops is about 245,000 tons carbon dioxide equivalents per year.
- Retirement of 35,000 acres of field crops and conversion to rice resulted in a non-Delta GWP change of -25,270 tons carbon dioxide equivalents per year. The baseline emissions associated with field crops is about 245,000 tons carbon dioxide equivalents per year. A key reason for the large net removal is the decrease in non-Delta rice acreage that was then

multiplied by the estimated per acre emissions of 4.8 tons carbon dioxide equivalents per acre per year on mineral soils in California.

- Retirement of 10,000 acres of pasture and conversion to wetlands resulted in a non-Delta GWP change of 1,296 tons carbon dioxide equivalents per year. The baseline emissions associated with pasture is about 70,000 tons carbon dioxide equivalents per year.
- Retirement of 10,000 acres of pasture and conversion to rice result in a net GWP change of -5,788 tons carbon dioxide equivalents per year relative to the NAA. For comparison, the estimated baseline emission for the 10,000 acres of pasture in the Delta is about 70,000 tons carbon dioxide equivalents per year.
- We estimated uncertainty by using the standard error associated with the GWP estimates. In all alternatives except for alternative 4, the range of GWP changes was insignificant (3% or less) relative to baseline emissions.
- Where rice acreage increases in the Delta, our results indicate a net statewide GWP benefit due to the decrease in rice acreage in non-Delta areas where there are large GHG emissions on mineral soils.

A.5 ERA ECONOMIC ANALYSIS TECHNICAL MEMORANDUM

Prepared by: Duncan MacEwan, ERA Economics
Prepared for: Steve Deverel, HydroFocus
August 12, 2014

This technical memorandum briefly describes the methods, results, and limitations of an economic analysis of land use change in the Sacramento-San Joaquin Delta (Delta) using the Statewide Agricultural Production (SWAP) model. The purpose of this analysis was to evaluate the potential “leakage” effects from four (4) Delta land use policies. Leakage is a term used to describe the offset of carbon (or other) policy benefits caused by a shift in economic activity to another region. For the purposes of this analysis, leakage is defined as the shift in agricultural production to other regions of California as a result of land retirement policies in the Delta.

It is important to note that changes in land use resulting from environmental (e.g., carbon) policy, and the partial offsetting effects of leakage, are clearly driven by the economics of the crops being produced. An effective Delta land use policy must alter the relative profitability of crops, considering conditions in domestic and international export markets, in order to incentivize growers to shift production systems or retire land. In this analysis no attempt has been made to model land use change as an endogenous outcome of some incentive structure. Instead, land use change has been imposed as an exogenous policy constraint. It follows that this study should be viewed as a partial equilibrium analysis of Delta land use policy that is mandated and therefore decoupled entirely from economics, holding all other factors constant. The estimated leakage represents one outcome resulting from a series of critically important

simplifying assumptions. In practice, a significant incentive structure would need to be in place to affect the type and scale of land use conversion considered in this analysis.

More careful general equilibrium and sensitivity analysis should be performed prior to drawing any policy conclusions from the results summarized in this technical memorandum.

A.5.1 Analytic Approach

The SWAP model is a regional agricultural production and economic optimization model that simulates the decisions of farmers across 93 percent of agricultural land in California. It is the most current in a series of California agricultural production models, originally developed by researchers at the University of California at Davis in collaboration with the California Department of Water Resources with additional funding provided by the United States Bureau of Reclamation. The SWAP model has been subject to peer-review (Howitt et al. 2012). The SWAP model and its predecessor the Central Valley Production Model (CVPM) have been used for numerous policy analyses and impact studies over the past 15 years, including the impacts of the Central Valley Project Improvement Act, Upper San Joaquin Basin Storage Investigation, the SWP drought impact analysis, and the economic implications of Delta conveyance options (MacEwan and Hatchett 2012).

The SWAP model was used to estimate the following scenarios (alternatives):

- No Action Alternative (NAA)
- Remove 35,000 acres of field crops from the Delta and leave the land fallow
- Remove 35,000 acres of field crops from the Delta and convert those acres to rice
- Remove 10,000 acres of irrigated pasture from the Delta and leave the land fallow
- Remove 10,000 acres of irrigated pasture from the Delta and convert those acres to rice

A.5.2 Key Assumptions

Field crops for this analysis were defined as safflower, sudan grass and other miscellaneous field crops, and corn. Year 2030 was assumed for the level of development. Other key assumptions include:

- Crop demand: linear shift based on changes in real income and population. No attempt was made to model international export markets, it was assumed that California maintains a constant export share in the international market.
- Real electricity cost: held constant.
- Other inputs real cost: held constant.
- Technological change: not modeled.
- Climate effects (changes in crop yield and ET): not modeled.

- Surface water deliveries: CVP, SWP, and local supplies were held constant.
- Groundwater depth and installed capacity: held constant.
- Urban development (ag-urban land conversion): not modeled.

A.5.3 Results

The impact of an alternative is defined as the difference between the NAA and that alternative. This analysis holds all other factors constant, given the assumptions described above, to estimate the shift in statewide crop production in response to each policy alternative.

The 27 Central Valley SWAP model regions were aggregated into 4 regions, including the Sacramento Valley, Delta, San Joaquin River, and Tulare Lake Basin. Additional SWAP model regions along the central coast and southern California were not included in the analysis because these regions are generally decoupled from the Central Valley market. The 20 standard crop groups modeled in SWAP were aggregated into 7 groups: trees and vineyards, irrigated pasture, rice, miscellaneous field crops including corn, forage and other field crops, vegetables, and cotton. The accompanying Excel workbook summarizes the results. This section provides a brief summary of the findings.

A.5.3.1 NO ACTION ALTERNATIVE

The 2030 NAA provides the baseline against which the future policy runs are compared. Agricultural land use is expected to contract slightly by 2030, by around 6.5 million irrigated acres (~5%) statewide, including a contraction to 367,000 acres in the Delta. This is consistent with the recent trends in California toward more intensive tree and specialty crop production on a smaller land footprint. Climate change, international markets, relative energy costs, and resource conditions such as surface and groundwater availability will affect the 2030 NAA, but were held constant in this analysis. Irrigated pasture in the Delta is estimated to decrease from approximately 14,000 acres to 10,000 acres.

Table 36: No Action Alternative (2030) Land Use, Thousands of Acres

REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
SACRAMENTO	611	73	575	124	203	142	2
DELTA	48	10	5	152	97	54	0

REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
SAN JOAQUIN	603	25	11	382	192	202	60
TULARE	1,280	23	0	561	533	353	205

A.5.3.2 ALTERNATIVES

ALTERNATIVE 2 – RETIRE 35,000 ACRES FIELD CROPS

In alternative 2, 35,000 acres of field crops (corn, safflower, and "other field crops") are removed from the Delta and the land is left fallow. The statewide change in the total irrigated footprint is slightly less than 35,000 acres, indicating limited crop substitution to other regions as farmers adjust crop mix in response to changing relative prices.

Table 37: Alternative 2 (2030) Land Use, Thousands of Acres

REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
SACRA-MENTO	611	73	575	125	203	142	2
DELTA	47	15	5	116	94	54	0
SAN JOAQUIN	603	25	11	383	192	202	60
TULARE	1,280	23	0	563	533	353	205

ALTERNATIVE 3 – RETIRE 35,000 ACRES FIELD CROPS AND CONVERT TO RICE

Alternative 3 is the same as alternative 2 except the acreage is converted entirely to rice. This analysis assumed that land use conversion is exogenously mandated. The statewide decrease in the total irrigated footprint is estimated to be less than 20,000 acres.

Table 38: Alternative 3 (2030) Land Use, Thousands of Acres

REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
SACRA-MENTO	613	73	572	125	204	143	3
DELTA	48	0	40	117	86	54	0
SAN JOAQUIN	603	25	10	383	192	202	60
TULARE	1,280	23	0	562	534	353	205

ALTERNATIVE 4 – RETIRE 10,000 ACRES IRRIGATED PASTURE

In alternative 4, 10,000 acres of irrigated pasture are removed from the Delta and that land is left fallow. Statewide irrigated acreage decreases by approximately the same amount.

Table 39: Alternative 4 (2030) Land Use, Thousands of Acres

REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
SACRA-MENTO	611	73	575	124	203	142	2
DELTA	48	0	5	150	99	54	0
SAN JOAQUIN	603	25	11	382	192	202	60
TULARE	1,280	23	0	561	533	353	205

ALTERNATIVE 5 – RETIRE 13,800 ACRES IRRIGATED PASTURE AND CONVERT TO RICE

Alternative 5 is the same as alternative 4 except the acreage is converted entirely to rice. It is important to note, again, that this analysis assumed that land use conversion is exogenously mandated. The statewide total irrigated area is estimated to increase by just over 1,000 acres.

Table 40: Alternative 5 (2030) Land Use, Thousands of Acres

REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
SACRA-MENTO	611	73	574	124	204	143	3
DELTA	48	0	15	152	98	54	0
SAN JOAQUIN	603	25	11	382	192	202	60
TULARE	1,280	23	0	561	533	353	205

The leakage analysis is primarily concerned with the change in crop mix and shift in production to other regions of California. The leakage effect is fundamentally driven by basic supply and demand principles of economics. When the production of a crop(s) decreases in response to Delta land use policy, all else constant, the price of that crop(s) will increase. As the price of that crop(s) increases this will change the relative profitability of crops in all other regions in the state, and in response, growers may switch production systems and change the statewide crop mix. The magnitude of this effect is driven by a number of factors including domestic and international market conditions, the relative supply and demand elasticities of all crops, and cross-price elasticities. In addition, there are intensive margin (for example, input use per acre) adjustments to production that affect the magnitude of leakage. The following subsections briefly describe the results of the leakage analysis and summarize key trends.

A.5.3.3 ALTERNATIVES

ALTERNATIVE 2

A total of 35,992 acres of corn, other field, and safflower crops (35,000 attributed to the policy and 992 attributed to market adjustment) are removed from the Delta. 35,000 acres of land is left fallow and the total irrigated acreage in the Delta decreases by the same amount.

The decrease in Delta field crop production increases the statewide price for field crops, causing an additional 3,200 acres to be planted in the Sacramento, San Joaquin and Tulare Basin areas of the Central Valley. The additional acreage in other regions comes from a small shift in the crop mix, meaning a decrease in the acreage of some other crops. For example, growers in the Tulare Lake Basin plant 500 fewer acres of irrigated pasture and substitute toward other field crops.

ALTERNATIVE 3

35,000 acres of field crops removed from the Delta are converted to rice. The increased rice production in the Delta puts downward pressure on rice prices and rice production decreases, primarily in the Sacramento Valley. In response to the decreased rice production, the Sacramento Valley production shifts to other crops including deciduous and forage crops. This causes a change in the market price of those crops and production decreases in other regions and the market reaches a new equilibrium.

ALTERNATIVE 4

A total of 10,000 acres of irrigated pasture are removed from the Delta and the land is left fallow. Fallowing 10,000 acres of pasture has a small statewide price effect and other regions slightly increase production. There is a correspondingly small shift in the crop mix to accommodate the increase in pasture acreage in these regions.

ALTERNATIVE 5

10,000 acres of irrigated pasture are removed from the Delta and converted to rice.

Similar to alternative 3, the increased rice production in the Delta puts downward pressure on rice prices and rice production decreases, primarily in the Sacramento Valley. The Sacramento Valley production adjusts and shifts to other crops including deciduous, pasture and other forage crops. This causes a change in the market price of those crops and production adjusts in other regions until the market reaches a new equilibrium.

Table 41: Change in Irrigated Acreage from NAA

SCENARIO	REGION	TREES AND VINES	PASTURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGETABLES	COTTON
A2 FALLOW FIELD	SACRAMENTO	-9	-178	-5	920	-247	-49	-1
	DELTA	-522	5,119	6	-35,992	-2,948	-662	0
	SAN JOAQUIN	-106	-72	-2	853	-359	-51	-45
	TULARE	-101	-498	0	1,422	-384	-36	-96
A3 FIELD TO RICE	SACRAMENTO	2,414	557	-2,919	914	583	124	55
	DELTA	-257	-10,071	35,000	-35,000	-11,029	-449	0

SCENARIO	REGION	TREES AND VINES	PAS-TURE	RICE	FIELD	OTHER FIELD/ FORAGE	VEGE-TABLES	COT-TON
	SAN JOAQUIN	-447	-59	-111	630	133	-53	-49
	TULARE	-276	-364	0	664	172	-66	-201
A4 FALLOW PASTURE	SACRA-MENTO	-11	110	11	14	-77	-2	0
	DELTA	-54	-10,000	71	-1,768	1,732	19	0
	SAN JOAQUIN	31	60	3	79	-118	-1	1
	TULARE	24	114	0	62	-148	10	42
A5 PASTURE TO RICE	SACRA-MENTO	883	298	-936	-11	186	56	18
	DELTA	4	-10,000	10,000	60	378	11	0
	SAN JOAQUIN	-73	48	-26	52	12	1	-1
	TULARE	-33	78	0	-23	1	2	3

A.5.4 Limitations

There are several important limitations of this analysis. First, the standard caveats to any analysis using SWAP or other economic optimization models apply.

The SWAP model is an optimization model that makes the best (most profitable) adjustments to water supply and other changes. Constraints can be imposed to simulate restrictions on how much adjustment is possible or how fast the adjustment can realistically occur. Nevertheless, an optimization model can tend to over-adjust and minimize costs associated with detrimental changes or, similarly, maximize benefits associated with positive changes.

The SWAP model does not explicitly account for the dynamic nature of agricultural production; it provides a point-in-time comparison between two conditions. This is consistent with the way

most economic and environmental impact analysis is conducted, but it can obscure sometimes important adjustment costs.

The SWAP model also does not explicitly incorporate risk or risk preferences (e.g., risk aversion) into its objective function. Risk and variability are handled in two ways. First, the calibration procedure for SWAP is designed to reproduce observed crop mix, so to the extent that crop mix incorporates risk spreading and risk aversion, the starting, calibrated SWAP base condition will also. Second, variability in water delivery, prices, yields, or other parameters can be evaluated by running the model over a sequence of conditions or over a set of conditions that characterize a distribution, such as a set of water year types.

In addition, there are several important limitations to the current analysis stemming from the assumptions.

The analysis assumes a single statewide supply and demand elasticity for all crops. Further analysis should consider the different types of rice and geographic differences in elasticities. Additionally, the key supply elasticity used in the SWAP model is the acreage response elasticity, which means that other dimensions of supply response are not explicitly calibrated in the model.

California's export share to international markets has been assumed to remain constant. Sensitivity analysis of Asian export markets and production in other Mediterranean climate regions should be considered.

Finally, this analysis did not attempt to model infrastructure capacity to support rice production, including mills and crop insurance. Future analysis should consider the capacity to support rice production in the Delta and third-party (indirect and induced) impacts.

A.5.5 SWAP Model References

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Duncan MacEwan and Stephen Hatchett. (2012). Statewide Agricultural Production Model Update and Application to Federal Feasibility Analysis. Prepared for United States Department of the Interior, Bureau of Reclamation Mid-Pacific Region. 104 pp.

APPENDIX B: GHG FLUXES IN THE DELTA

B.1 BASELINE CONDITIONS IN THE SACRAMENTO-SAN JOAQUIN DELTA

Beginning in 1990, the US Geological Survey measured CO_2 emissions and correlated these with subsidence measurements[14,15,16] in pasture, grain and asparagus fields in the western and central Delta. UC Berkeley researchers used eddy covariance techniques and chambers to determine CO_2, NO_2, and CH_4 emissions and the annual carbon balance in a pasture on Sherman Island starting in 2006.[17,18] Recently, UC Berkeley researchers have expanded the scope of their measurements to include areas on Twitchell and Sherman islands. During 2011 and 2012, the US Geological Survey used eddy covariance techniques to estimate annual carbon balances that included CO_2 and CH_4 emission determination on Staten Island in the central Delta.[19] Also, Miller[20] used chambers to measure GHG fluxes on Twitchell Island. Deverel and Leighton[21] developed a model for estimating baseline CO_2 emissions from the oxidation of organic soils.

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[17] J. A. Hatala, M. Detto, O. Sonnentag, S. J. Deverel, J. Verfaillie, and D. D. Baldocchi. (2012). Greenhouse gas (CO_2, CH_4, H_2O) fluxes from drained and flooded agricultural peatlands in the Sacramento-San Joaquin Delta, *Agriculture, Ecosystems and Environment, 150*, 1-18.

[18] Y. A. Teh, W. L. Silver, O. Sonnentag, M. Detto, M. Kelly, and D. D. Baldocchi. (2011). Large greenhouse gas emissions from a temperate peatland pasture. *Ecosystems 14*, 311–325.

[19] US Geological Survey. (2013). Assessing the role of winter flooding on baseline greenhouse gas fluxes from corn fields in the Sacramento– San Joaquin Bay Delta, Final Project Report for the California Energy Commission.

[20] R. Miller. (2011). Carbon gas fluxes in re-established wetlands on organic soils differ relative to plant community and hydrology. *Wetlands* doi 10.1007/s13157-011-0215-2.

[21] S. J. Deverel and D. A. Leighton. (2010). Historic, recent, and future subsidence, Sacramento-San Joaquin Delta, California, USA. *San Francisco Estuary and Watershed Science 8* (2). https://escholarship.org/uc/item/7xd4x0xw.pdf.

Recent GHG emissions measurements range from 6.6 to 8.6 MT CO_2e $A^{-1}yr^{-1}$.[22] GHG emissions from and subsidence of peat soils are directly correlated with depth to groundwater; deeper groundwater corresponds to larger GHG emissions and higher subsidence rates where other factors such as soil organic matter content and temperature are constant.[23,24] Under baseline agricultural conditions, N_2O is emitted as the result of fertilizer use and organic matter decomposition. Reported emissions due to organic matter decomposition in drained highly organic soils are substantially larger than those due to fertilizer applications.[25,26] N_2O emissions have been measured infrequently in the Delta. Assa and Horwath[27] measured an annual N_2O emission of about 7.7 kilograms (kg) N_2O per acre (2.4 tons carbon dioxide equivalents per acre) in corn on Twitchell Island. Teh and others[28] reported similar values for pasture on Sherman Island. Ye and Horwath[29] reported annual N_2O emissions in rice ranging from 0 to 1 kg nitrogen per acre (0 to 0.3 MT CO_2e $A^{-1}yr^{-1}$). These studies demonstrated the episodic nature of N_2O emissions, large spatial variability, and dependence on fertilizer amounts and soil organic matter content.

[22] S. H. Knox, C. Sturtevant, J. H. Matthes, L. Koteen, J. Verfaillie, and D. Baldocchi (2014). Agricultural peatland restoration: effects of land-use change on GHG (CO_2 and CH_4) fluxes in the Sacramento-San Joaquin Delta. *Global Change Biology, 21*, 750–765.

[23] J. Couwenberg and A. Hooijer (2013). Towards a robust subsidence-based soil carbon emission factors for peat soils. *Mires and Peat, 12,* 1-13.

[24] J. C. Stephens, L. H. Allen, and E. Chen. (1984). Organic soil subsidence. In *Man-Induced Land Subsidence*. Reviews in Engineering Geology, Vol. VI (T. L. Holzer, ed.). Boulder, CO: Geological Society of America.

[25] A. Kasimir-Klemedtsson, L. Klemedtsson, K. Berglund, P. Martikainen, J. Silvola, and O. Oenema. (1997). GHG emissions from farmed organic soils; a review. *Soil Use and Management 13*, 245-250.

[26] C. Li, J. Six, W. R. Horwath, and W. Salas. (2014). Calibrating, Validating, and Implementing Process Models for California Agriculture GHG Emissions, Final Report to the Air Resources Board. February 27, 2014.

[27] Y. Assa and W. Horwath. (2011). Report on GHG emissions study in Twitchell Island in Corn and Rice Systems conducted in Spring 2010-Fall 2011.

[28] Y. A. Teh, W. L. Silver, O. Sonnentag, M. Detto, M. Kelly, and D. D. Baldocchi. (2011). Large greenhouse gas emissions from a temperate peatland pasture. *Ecosystems 14*, 311–325.

[29] R. Ye and W. R. Horwath. (2014). Influence of variable soil C on CH_4 and N_2O emissions from rice fields, presentation at UC Davis.

Figure 5: Agricultural Baseline Carbon Fluxes

Under drained conditions for traditional agricultural crops, exposure and oxidation of organic soil to oxygen results in oxidation and net emissions of CO_2, CH_4, and N_2O.

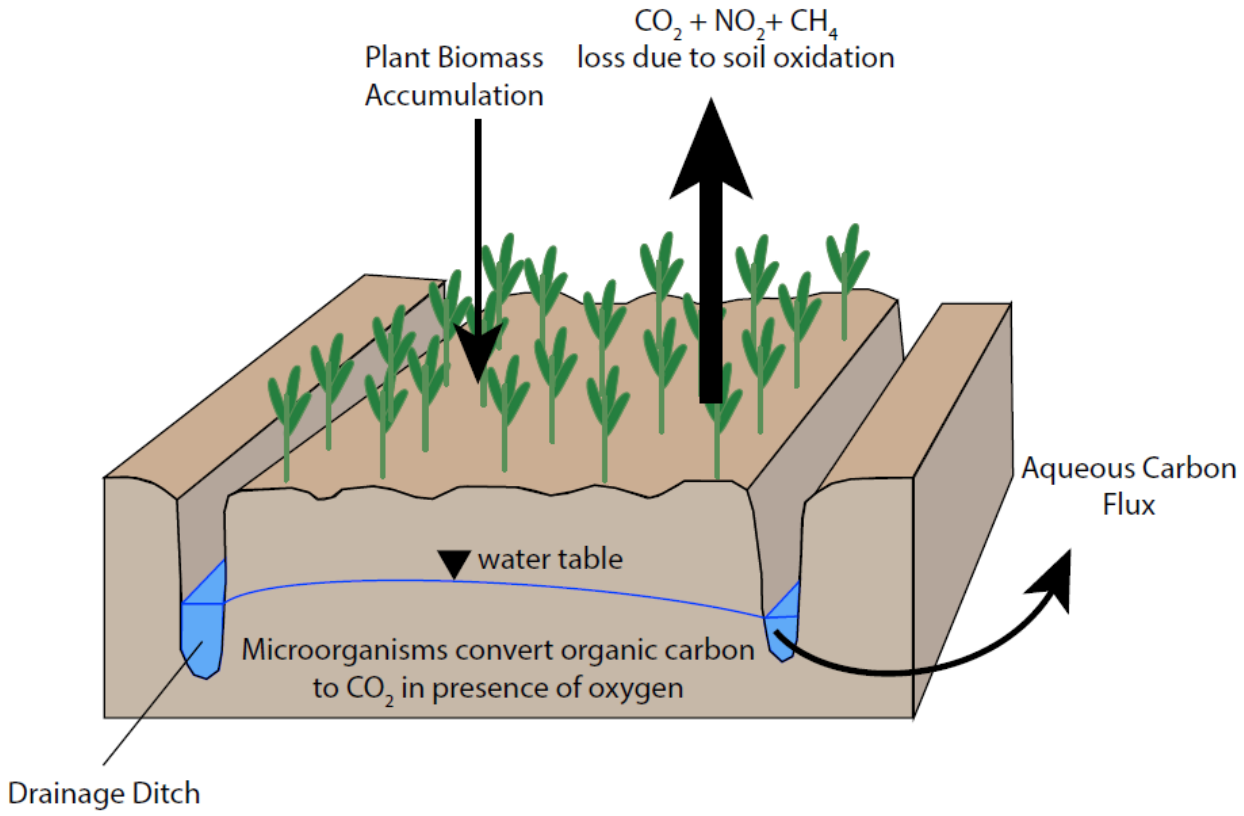


Table 42: Measured and Modeled CO_2-e Baseline Emissions

Summary of the published and recently reported net carbon balance and model estimates for the Delta.

SITE	SOIL CARBON (%)	AVERAGE GROUND-WATER DEPTH (CM)	MEASURED CO_2-E EMISSIONS (TONS/A-YEAR)	MODELED CO_2-E (TONS/A-YEAR)
Twitchell Corn (UC Berkeley)[31]	16	82	9	9
Sherman Pasture (UC Berkeley)[32]	12.5	60	2.8 - 5.2	3.3 - 5.6
Sherman Pasture (USGS, 1991 - 1992)[33]	14	70	5.2 - 8.2	6.7
Jersey pasture (USGS 1991 - 1992)	10	60	6.4	6.3
Staten Corn (USGS)[34]	10.5 - 16	130	8.6	8.6

[30] Using the model described in S. J. Deverel and D. A. Leighton. (2010). Historic, Recent, and Future Subsidence, Sacramento-San Joaquin Delta, California, USA. *San Francisco Estuary and Watershed Science* 8(2).

[31] S. H. Knox, C. Sturtevant, J. H. Matthes, L. Koteen, J. Verfaillie, and D. D. Baldocchi. (2015). Agricultural peatland restoration: effects of land-use change on greenhouse gas (CO_2 and CH_4) fluxes in the Sacramento-San Joaquin Delta. *Global Change Biology, 21*(2), 750–765.

[32] J. A. Hatala, M. Detto, O. Sonnentag, S J. Deverel, J. Verfaillie, and D. D. Baldocchi. (2012). Greenhouse gas (CO_2, CH_4, H_2O) fluxes from drained and flooded agricultural peatlands in the Sacramento-San Joaquin Delta. *Agriculture, Ecosystems and Environment*, 150, 1-18.

[33] S. J. Deverel and S. Rojstaczer. (1996). Subsidence of agricultural lands in the Sacramento-San Joaquin Delta, California: role of aqueous and gaseous carbon fluxes. *Water Resources Research 32*(8), 2359–23672.

[34] Pellerin, Brian; Frank Anderson; Brian Bergamaschi. (U.S. Geological Survey). 2014. Assessing the Role of Winter Flooding on Baseline Greenhouse Gas Fluxes from Corn Fields in the Sacramento – San Joaquin Bay Delta. *California Energy Commission*. Publication number: CEC-500-2014-077.

B.2 PROJECT CONDITIONS

B.2.1 Managed, Permanently Flooded, Non-Tidal Wetlands on Subsided Lands

Under the hypothesis that construction of these permanently flooded impounded marshes would stop subsidence and carbon loss, experiments were conducted in 1,000-m^2 enclosures on Twitchell Island beginning in 1993. Deverel el al.[35] reported a net carbon gain in permanently flooded impounded marshes and thus demonstrated their ability to stop and reverse the effects of subsidence. These results and those of Miller et al.[36] led to the conversion of 6 ha of agricultural land to the impounded marsh demonstration project on Twitchell Island[37] in 1997 by Department of Water Resources, HydroFocus, Inc., Reclamation District 1601, and US Geological Survey California Water Science Center (USGSCWSC) personnel. Vertical accretion in the Twitchell marsh varied spatially and depended on water depth, plant community composition and colonization, degree of marsh maturity, and water residence time.[38] The largest rates occurred in the deeper-water pond within dense stands of Schoenoplectus acutus (hardstem bulrush) and Typha (cattail) species.

Studies conducted in the Twitchell Island wetland indicate annual GHG removal rates in the pilot wetland (both east and west ponds) ranging from about 2 to 14 tons carbon dioxide per acre.[39] However, Anderson et al.[40] presented data that indicate substantial inter-annual variations in global warming potential in the Twitchell Island wetland studied by Miller et al. (2008).

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[35] S. J. Deverel, B. Wang, and S. Rojstaczer. (1998). Subsidence in the Sacramento–San Joaquin Delta. Pp. 489-502 in Proceedings of the Joseph Poland Subsidence Symposium (J. W. Borchers, ed.), Special Publication No. 8, Association of Engineering Geologists.

[36] R. L. Miller, L. Hastings, and R. Fujii (2000). Hydrologic treatments affect gaseous carbon loss from organic soils, Twitchell Island, California, October 1995-December 1997. US Geological Survey Water-Resources Investigations Report 2000-4042, 21pp.

[37] R. L. Miller, M. S. Fram, G. Wheeler, and R. Fujii. (2008). Subsidence reversal in a re-established wetland in the Sacramento-San Joaquin Delta, California, USA. *San Francisco Estuary and Watershed Science 6*(3), 1-24.

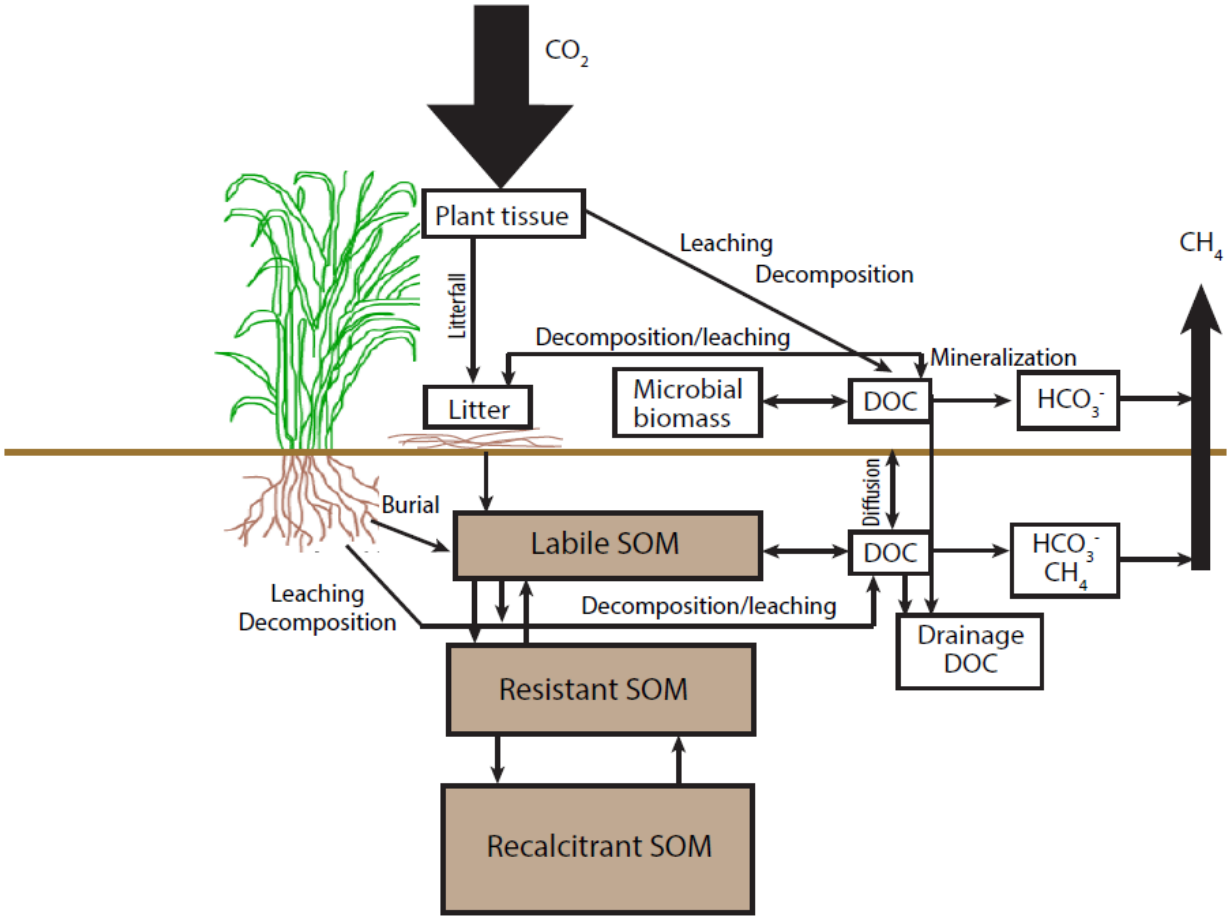
[38] R. L. Miller, M. S. Fram, G. Wheeler, and R. Fujii. (2008). Subsidence reversal in a re-established wetland in the Sacramento-San Joaquin Delta, California, USA. *San Francisco Estuary and Watershed Science 6*(3), 1-24.

[39] S. H. Knox, C. Sturtevant, J. H. Matthes, L. Koteen, J. Verfaillie, and D. Baldocchi. (2015). Agricultural peatland restoration: effects of land-use change on greenhouse gas (CO2 and CH4) fluxes in the Sacramento-San Joaquin Delta, Global Change Biology, *Global Change Biology, 21*(2), 750–765. R. L. Miller, M. S. Fram, R. Fujii, and G. Wheeler. (2008). Subsidence reversal in a re-established wetland in the Sacramento–San Joaquin Delta, California, USA. *San Francisco Estuary Watershed Science 6*(3). Available from: http://www.escholarship.org/uc/item/5j76502x

[40] F. E. Anderson, B. Bergamaschi, C. Sturtevant, S. Knox, L. Hastings, L. Windham-Myers, et al. (2016). Variation of energy and carbon fluxes from a restored temperate freshwater wetland and implications

The net GHG benefit equals the sum of CO_2 sequestered and baseline GHG emissions minus CH_4 emission. N_2O is not emitted from permanently flooded wetlands similar to those on Twitchell Island[41,42,43] where wastewater is not applied.

Figure 6: Carbon Pathways in Managed Wetlands



for carbon market verification protocols. *Journal of Geophysical Research: Biogeosciences*, February. DOI: 10.1002/2015JG003083.

41 C. J. Smith, R. D. DeLaune, and W. H. Patrick Jr. (1983). Nitrous oxide emission from Gulf Coast wetlands. *Geochimica et Cosmochimica Acta 47*, 1805-1814.

42 J. Couwenberg, A. Thiele, F. Tanneberger, J. Augustin, S. Bärisch, D. Dubovik et al. (2011). Assessing greenhouse gas emissions from peatlands using vegetation as a proxy. *Hydrobiologia (2011) 674*, 67–89.

43 IPCC. (2013). 2013 Supplement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Wetlands, Chapter 3, Rewetted peatlands. http://www.ipcc-nggip.iges.or.jp/public/wetlands/

(Adapted from Richards and Vespaskas). Large amounts of CO_2 are stored in plant tissue and relatively small amounts of carbon are emitted as CH_4 to result in a net carbon sequestration.

B.2.2 Recommended Best Management Practices for Rice in the Sacramento-San Joaquin Delta

Based on data collection efforts during 2008–2014, the following best management practices are indicated for rice production in the western Delta:

- To minimize loads of organic carbon and methyl mercury to Delta surface water bodies, strategies should be developed that promote recycling and reuse of island and rice-field drainage water. These strategies will include use of rice drainage water for irrigation of other crops and wetlands, irrigation with water from other crops, and recycling of rice drainage water.
- Maintenance of high water levels in rice drainage ditches will minimize seepage from rice fields and reduce water application needs.
- Drain water quality and flow monitoring will aid in managing on-island and off-island constituent loads.
- Concomitant with recycling and reuse is the need to assess and manage soil and irrigation-water salinity. Rice is a salt-sensitive crop and the reported threshold for the soil saturation extract salinity for yield declines in rice is 3 dS m^{-1}.[44] For continued rice production, salt leaching will be required where soil salinity approaches this value.
- Crop nitrogen needs vary depending on nitrogen contribution from soil organic matter.[45] To maximize nitrogen availability to the crop and minimize nitrous oxide emissions, fertilizer should be applied about a month after planting, immediately prior to flooding.
- Results presented here for Twitchell Island indicate less than 72 pounds nitrogen per acre are required and high yields were obtained with no addition of nitrogen. Soil nitrogen levels should be used to determine fertilizer requirements.

[44] C. M. Grieve, S. R. Grattan, and E. V. Maas. (2012). Plant salt tolerance. In Agricultural Salinity Assessment and Management, ASCE Manuals and Reports on Engineering Practice No. 71, Second Edition (W. W. Wallender and K. K. Tanji, eds.). New York: American Society of Civil Engineers.

[45] M. B. Espe, E. Kirk, C. van Kessel, W. H. Horwath, and B. A. Linquist. (2015). Indigenous nitrogen supply of rice is predicted by soil organic carbon. *Soil Science Society of America Journal*. doi:10.2136/sssaj2014.08.0328.

APPENDIX C: MODELS

C.1 MODEL SUBCALC

SUBCALC simulates microbial oxidation on agricultural organic soils using Michaelis–Menten kinetics in the Sacramento-San Joaquin Delta. Parameters for the model Michaelis–Menten equations were developed from field data. Inputs for the model are described in Deverel and Leighton and include soil organic matter content, average soil annual temperature at 30 cm, depth to groundwater, and soil bulk density (Deverel et al. 2016). Future updates to SUBCALC include integration with the PEPRMT model for predicting both CO_2 and CH_4 from diverse land use types in the Delta.

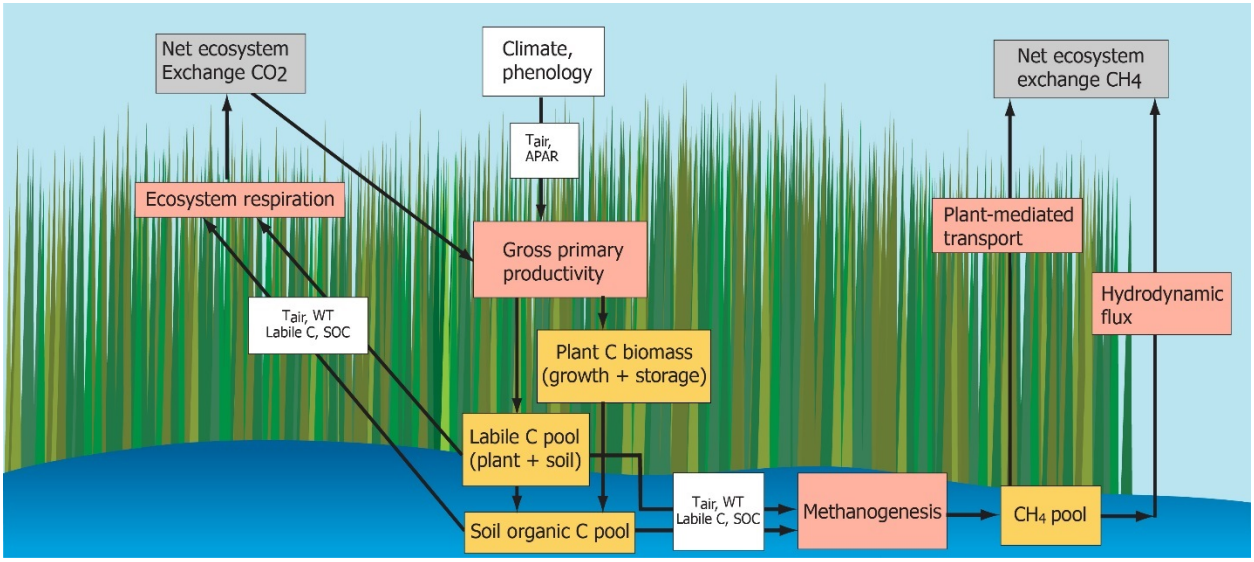
C.2 MODEL PEPRMT (PEATLAND, ECOSYSTEM, PHOTOSYNTHESIS, RESPIRATION AND METHANE TRANSPORT MODEL)

The Peatland Ecosystem Photosynthesis, Respiration, and Methane Transport model (PEPRMT, pronounced “peppermint,” and also referred to as LUE-DAMM) can be used for estimation of CO_2 and CH_4 exchange from wetlands in the Sacramento-San Joaquin Delta (Oikawa et al. 2017). This model has been calibrated and validated using a multi-year data set collected in a 14-acre (6 ha) mature restored wetland on Twitchell Island. Future updates to this model, including calibrations to restored wetlands of different ages (1-17 yr.) and a rice paddy, will be made publicly available: https://github.com/pattyoikawa/PEPRMT.git

The PEPRMT model requires leaf area index (LAI), meteorological data, initial soil organic carbon content (SOC), and water table height. Flux rates derived from the PEPRMT model, net ecosystem exchange of CO_2 (NEE; g CO_2 ha^{-1} day^{-1}), and net ecosystem exchange of CH_4 (RCH4; g CH_4 ha^{-1} day^{-1}) will be used to derive annual sums of CO_2 and CH_4 for each Project year and Project site.

Figure 7: Conceptual Diagram of PEPRMT Model

The conceptual basis for the PEPRMT model. Model inputs and drivers—air temperature (Tair), absorbed photosynthetically active radiation (APAR), water table height (WT), labile soil C, and soil organic carbon (SOC)—are shown in white boxes. Model outputs are shown in grey boxes. Processes and pools modeled within PEPRMT are shown in pink and orange boxes, respectively.



C.2.1 CO_2 Fluxes

In order to predict net ecosystem exchange of CO_2 (NEE) both gross primary productivity (GPP) and ecosystem respiration (R_{eco}) need to be simulated:

Equation 27

$$NEE = GPP + R_{eco}$$

To predict GPP, we employ a simple and widely used light use efficiency model called the LUE model (Monteith 1972):

Equation 28

$$GPP = PAR \times \varepsilon \times fPAR\,(LAI) \times f(T)$$

WHERE

GPP	is gross primary productivity
PAR	is photosynthetically active radiation
E	is plant light use efficiency
fPAR	is the fraction of PAR absorbed by canopy
LAI	is leaf area index
fT	is temperature function

The light use efficiency and temperature function are calibrated to each ecosystem, as these vary among plant species (Yuan et al. 2007). The temperature function assumes photosynthesis increases exponentially with temperature until it reaches an optimum (e.g., Topt =25°C), above which photosynthesis is inhibited.

Equation 29

$$f(T_k) = 1 \times \left(\frac{H_d \times \exp\left(\frac{H_a(T_k - T_{opt})}{T_k \times R \times T_{opt}}\right)}{H_d - H_a(1 - \exp\left(\frac{H_d(T_k - T_{opt})}{T_k \times R \times T_{opt}}\right)} \right)$$

WHERE

R	is the universal gas constant
T_k	is air temperature
H_a	is the rate of exponential increase below the optimum temperature
H_d	is the rate of decrease above the optimum temperature (Medlyn et al. 2002)

From these equations, photosynthetic rates are computed every 30 min and up-scaled to the ecosystem using LAI.

Ecosystem respiration (R_{eco}) is the total CO_2 respired by both plants and soil. In order to predict R_{eco} we employ a simple respiration model based on enzyme kinetics that was adapted from the Dual Arrhenius Michaelis-Menten kinetics (DAMM) model (Davidson et al. 2012). This model assumes R_{eco} is a function of the size and availability of two soil carbon pools, temperature, and water table height (WT). The two soil carbon pools (i.e., soil organic carbon [C_{soc}] and recently fixed photosynthetic carbon [C_{labile}], which is predicted using GPP) are regulated by initial soil carbon conditions. According to enzyme kinetics, respiration increases exponentially with temperature. Water table and soil moisture influence the availability of oxygen in the soil, an important substrate for aerobic respiration. Specifically, R_{eco} is predicted using an Arrhenius equation paired with Michaelis-Menten equations to address substrate availability of 2 carbon pools:

Equation 30

$$\mathbf{R_{eco}} = \left(\frac{\mathbf{Vmax_{SOC}} \times [\mathbf{C_{SOC}}]}{\mathbf{kM_{SOC}} + [\mathbf{C_{SOC}}]} + \frac{\mathbf{Vmax_{labile}} \times [\mathbf{C_{labile}}]}{\mathbf{kM_{labile}} + [\mathbf{C_{labile}}]} \right) \times \mathbf{f(WT)}$$

WHERE

R_{eco}	is the total respiration rate for the given ecosystem (µmol CO_2 m^{-2} s^{-1})
V_{max}	is the maximum rate of enzyme kinetics for the respective C pools when substrate concentrations are not limiting
C	is the soil C content for the respective C pools (µmol C m^{-2}) (where labile refers to recently-fixed photosynthetic C and soil organic carbon (SOC) refers to older more recalcitrant forms of C) (µmol CO_2 m^{-2} s^{-1})
kM	is the half-saturation concentration for the respective substrates (µmol C m^{-2})

Under flooded conditions, soil respiration is inhibited due to depleted O_2. Soil CO_2 emission rates under anaerobic conditions have been previously reported to decrease by 32–65% (Wright and Reddy 2001) due to the use of alternative electron acceptors, and were recently reported to be reduced by 50% in a Delta rangeland site (McNicol and Silver 2014). Therefore the water table function (f (WT)) describes elevated rates of respiration when the water table falls below the soil surface due to introduction of O_2 to the soil.

C pool sizes are dynamic. For example, both pools are reduced in response to respiration rates. The SOC pool is enhanced at the end of the year when vegetation senesces and contributes to the SOC pool, estimated as a function of LAI. The labile pool is a function of GPP (explained above). Initial SOC conditions for the simulated region is another driver for model simulation and must be sampled at the beginning of the project (5–10 soil profile samples to assess average SOC in the top 1m of soil; see below for complete list of drivers, parameters, and state variables).

Following the Arrhenius function, V_{max} is the maximum rate of enzyme reaction for each soil C pool (i.e., SOC and labile soil C):

Equation 31

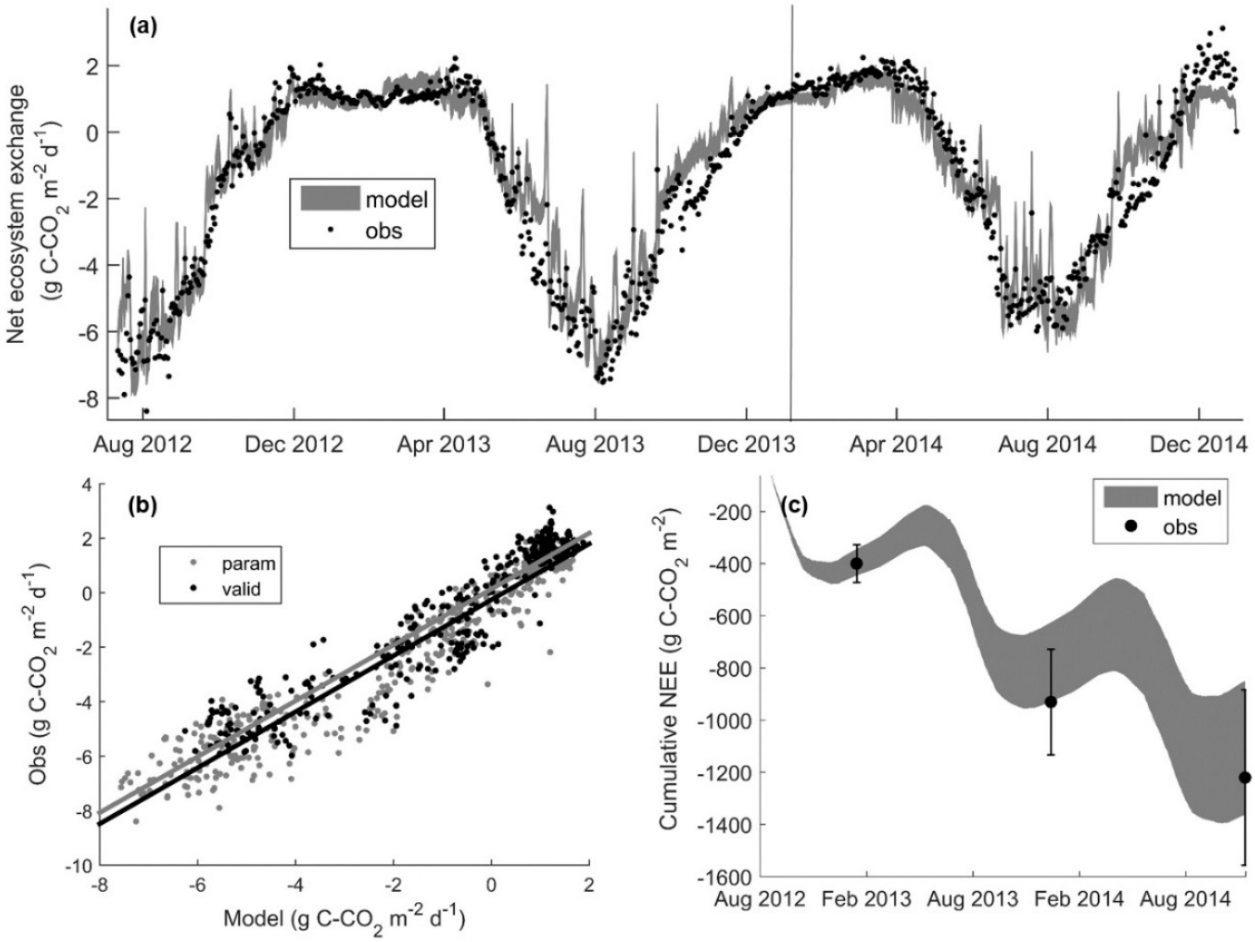
$$\mathbf{V_{max} = a_x \times e^{-Ea_x/RT}}$$

WHERE

V_{max}	is the maximum rate of enzyme reaction for each soil C pool (i.e., SOC and labile soil C)
a_x	is the pre-exponential factor
$\mathbf{Ea_x}$	is the activation energy of the enzymatic reaction with the substrate
T	is air temperature
R	is the universal gas constant

Figure 8 shows a comparison of the PEPRMT model to observations of NEE. Approximately 60% of observed data were used to parameterize the model (July 2012–December 2013), and 40% were used for model validation (January 2014–December 2014). PEPRMT model simulations explained 90% of the variation in observed CO_2 fluxes. Observed and modeled cumulative CO_2 budgets for the validation period were similar (observed: -290 ± 134g C-CO_2 m^{-2} yr^{-1}; modeled: -329.5 ± 105 g C-CO_2 m^{-2} yr^{-1}).

Figure 8: Comparison of PEPRMT Model to Observations of NEE



(a) PEPRMT modeled and observed net ecosystem exchange of CO_2 (NEE) from July 2012 to December 2014 at West Pond wetland. Data to the left of the black vertical line were used in model parameterization and data to the right were used in model validation. (

b) Data model agreement was high during the parameterization period (param) (slope=1, intercept=0.26; r^2 = 0.92; RMSE = 0.85) and during the validation period (valid) (slope=1, intercept=0.13; r^2 = 0.90; RMSE = 0.86).

(c) Similar integrated observed and modeled NEE fluxes were observed during the validation period (observed: -290 ± 134g C-CO_2 m^{-2} yr^{-1}; modeled: -329.5 ± 105 g C-CO_2 m^{-2} yr^{-1}) as well as across the entire observation period (observed: -1220.6 ± 336g C-CO_2 m^{-2} yr^{-1}; modeled: -1107.0 ± 257 g C-CO_2 m^{-2} yr^{-1}). Errors are 90% confidence intervals. Observed error is the sum of random and gap-filling errors. Model error is calculated based on variance across accepted posterior model parameters.

C.2.2 CH_4 Fluxes

In order to predict net CH_4 emissions, both CH_4 oxidation and production need to be simulated. Again, we employ a simple model based on enzyme kinetics where CH_4 production is a function of the size and availability of two soil C pools, temperature, and water table height, and CH_4 oxidation is a function of the availability of CH_4, temperature, and water table height. Both processes are predicted to increase exponentially with temperature. However, high water table conditions enhance CH_4 production and limit oxidation, and low water table heights inhibit CH_4 production and increase oxidation. Two transport pathways are also modeled: plant–mediated CH_4 transport and hydrodynamic CH_4 flux. Both of these transport pathways are dependent on water table height and concentration gradients of CH_4 between the water and atmosphere. Plant-mediated transport is also a function of GPP (Sturtevant et al. 2016; Poindexter et al. 2016).

The biogeochemical model for CH_4 production and oxidation is based on the DAMM model foundation. Similar to the R_{eco} DAMM model, CH_4 production is predicted using an Arrhenius equation paired with Michaelis-Menten equations estimating the concentration of two C substrates at the enzyme reaction site.

$$\mathbf{R_{CH4}} = \frac{\mathbf{Vmax_{labile}} \times [\mathbf{C_{labile}}]}{\mathbf{kM_{labile}} + [\mathbf{C_{labile}}]} \times \frac{\mathbf{Vmax_{SOC}} \times [\mathbf{C_{SOC}}]}{\mathbf{kM_{SOC}} + [\mathbf{C_{SOC}}]} \times \mathbf{f(WT)}$$

To account for the inhibition of CH_4 production by the presence of O_2, an O_2 effect parameter is applied when the water table falls below the soil surface. Previous research has indicated that CH_4 production rates can take multiple days to recover following re-saturation, due to the slow recharge of alternative electron acceptors (Kettunen et al. 1999; Moore and Dalva 1993). A previous analysis at the West Pond wetland confirmed that lowering the water table can have sustained negative effects on CH_4 emission, lasting up to 20 days (Sturtevant et al. 2016). We added a lag effect into the model, where CH_4 production is inhibited for 20 days following a drop in the water table.

CH_4 oxidation also follows the DAMM model foundation, where CH_4 is the only substrate

$$\mathbf{O_{CH4}} = \frac{\mathbf{Vmax_{CH4}} \times [\mathbf{CH_4}]}{\mathbf{kM_{CH4}} + [\mathbf{CH_4}]} \times \mathbf{f(WT)}$$

To account for the inhibition of CH_4 oxidation when the water table is above the soil surface, a water table function (f (WT)) is applied when the water table is above the soil surface.

Hydrodynamic flux is predicted using the Poindexter model, which was parameterized and validated at the same mature wetland site as the model described here (Poindexter et al. 2016). This predicts transfer of CH_4 stored in the water directly to the atmosphere given the concentration gradient between CH_4 in water and CH_4 in the atmosphere as well as a gas transfer velocity:

$$\mathbf{F_{hydro}} = \mathbf{k_{hydro}} \times ([\mathbf{CH4_{water}}] - [\mathbf{CH4_{surface}}])$$

Where k_{hydro} is the gas transfer velocity through the water (0.04 m d^{-1}). Concentrations of CH_4 in the water or soil ([CH_{4water}]; µmol m^{-3}) are modeled based on production and oxidation rates of CH_4. After accounting for CH_4 solubility in water, dissolved concentrations of methane at the surface ([$CH_{4surface}$]; µmol m^{-3}) are so small they are assumed to be zero.

Plant-mediated flux is predicted following the Dynamic Land Ecosystem Model (DLEM) (Tian et al. 2010). This predicts plant-mediated transport of CH_4 given the concentration gradient between CH_4 in water and CH_4 in the atmosphere as well as plant transport efficiency and plant activity:

$$\mathbf{F_{plant}} = (\mathbf{k_{plant}} \times ([\mathbf{CH4_{water}}] - [\mathbf{CH4_{atm}}]) \times \frac{\mathbf{GPP}}{\mathbf{GPP_{max}}}) \times \mathbf{Voxi}$$

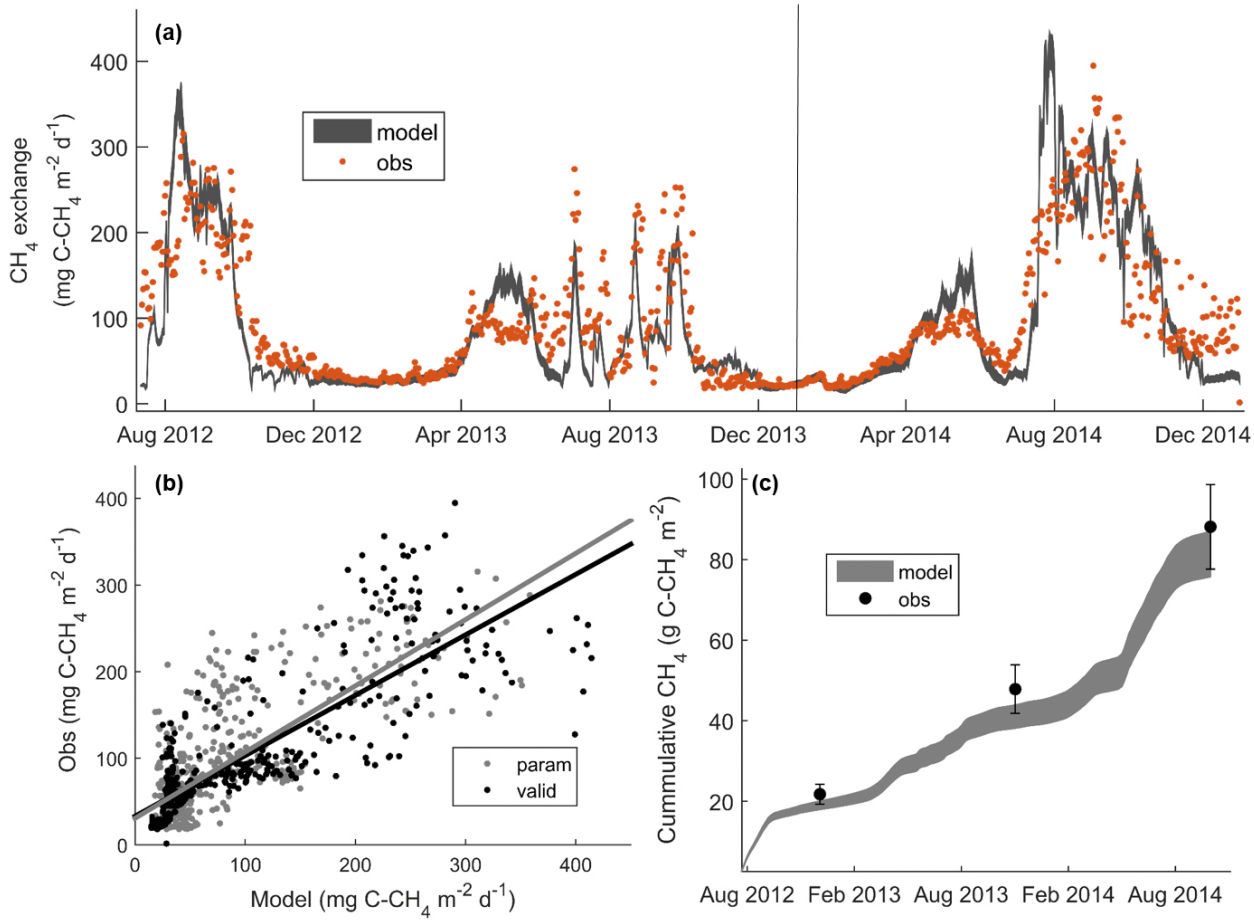
where k_{plant} is the gas transfer velocity through plants, assumed to be constant (0.24 m d^{-1}) (Moore and Dalva 1993). Concentrations of CH_4 in the soil and water ([CH_{4water}]; µmol m^{-3}) are modeled based on production and oxidation rates of CH_4. Again, after accounting for CH_4 solubility in water, dissolved concentrations of CH_4 in the atmosphere ([CH_{4atm}]; µmol m^{-3}) are so small, they are assumed to be zero. Plant activity is assessed using GPP, where the most plant transport is expected to occur when GPP is at its highest point. Finally, a fraction of CH_4 transported through plants is assumed to be oxidized at a constant rate (V_{oxi} =0.35) (van der Nat and Middelburg, 1998b).

Figure 9 compares the PEPRMT modeled CH_4 flux in West Pond Wetland. PEPRMT model simulations explained 65% of the variation in observed CH_4 fluxes. Observed and modeled cumulative CH_4 budgets for the validation period were very similar (observed: 40.3 ± 4.5 g C-CH_4 m^{-2} yr^{-1}; modeled: 40.4 ± 2.8 g C- CH_4 m^{-2} yr^{-1}).

Figure 9: Comparison of PEPRMT Model to Observations of CH_4.

(a) PEPRMT modeled and observed ecosystem exchange of CH_4 in West Pond wetland. Data to the left of the black vertical line were used in model parameterization and data to the right were used in model validation. (b) Data-model agreement was high during the parameterization period (param) (slope = 0.76, intercept = 31; r^2 = 0.60; RMSE = 48.6) and during the validation period (valid) (slope = 0.7, intercept = 33; r^2 = 0.67; RMSE = 57.2). (c) Similar integrated observed and modeled CH_4 fluxes were observed during the parameterization period (observed: 47.9 ± 6 g C- CH_4 m^{-2}; modeled: 41.0 ± 3.0 g C- CH_4 m^{-2}) and validation period (observed: 40.3 ± 4.5 g C- CH_4 m^{-2} yr^{-1}; modeled: 40.4 ± 2.8 g C- CH_4 m^{-2} yr^{-1}). Across the entire observation period budgets were similar (observed: 88.2± 10.5 g C- CH_4 m^{-2}; modeled: 81.4± 6.0 6 g C- CH_4 m^{-2}). Errors are 90% confidence intervals. Observed error is the sum of random and gap-filling errors.

Model error is calculated based variance across accepted posterior model parameters.



C.2.3 Data and Parameters Monitored

DATA UNIT/PARAMETER	METEOROLOGICAL DATA
Description	Air temperature and in-coming radiation
Units	Degree Celsius and µmol radiation m^{-2} s^{-1}
Data source	California Irrigation Management Information System (CIMIS) website (http://wwwcimis.water.ca.gov/cimis/data.jsp)

Frequency of monitoring/recording	30 min

DATA UNIT/PARAMETER	**INITIAL SOIL ORGANIC CARBON**
Description	Amount of existing soil organic carbon at beginning of Project
Units	g C m^{-3} soil
Data source	Direct sampling (5-10 soil profile samples averaged across top 1m soil; replicate spatially as needed) is recommended. Soil organic carbon can be accurately estimated from loss on ignition using data presented Callaway et al. (2012) and Drexler et al. (2009).
Description of measurement methods and procedures to be applied	If data from NRCS SSURGO is used, the uncertainty in the spatial resolution of soils properties (including soil organic matter) must be accounted for in model inputs
Frequency of monitoring/recording	Once at beginning of Project

DATA UNIT/PARAMETER	**WATER TABLE HEIGHT**
Description	Distance from surface of soil to water table—for Project conditions
Units	cm
Data source	Direct or automated measurement
Description of measurement methods and procedures to be applied	Measure by hand distance of water height to soil surface or install pressure transducer to continuously monitor water table height (such as Campbell Scientific CS451-L)
Frequency of monitoring/recording	Daily-weekly

Description	Distance from surface of soil to water table—for Project conditions

DATA UNIT/PARAMETER	**LEAF AREA INDEX**
Description	One-sided green leaf area per ground surface area
Units	m^2 leaf area m^{-2} ground area
Data source	Destructive field sampling, LAI sensor (e.g., LAI-2200C Plant Canopy Analyzer), or remote sensing
Description of measurement methods and procedures to be applied	Destructive sampling: remove all leaves in a known surface area (e.g.40 cm x 40 cm), measure leaf area of all removed leaves. Repeat across landscape (ideally 5 measurements per plant cover type). LAI sensor: collect 10 measurements along a transect through each plant cover type Remote sensing: Phenocams, or digital cameras that are automated to record images of canopy cover throughout the year, can be used to calculate a greenness index (GI) that can be empirically related to LAI based on field measurements (Richardson et al. 2009, Ryu et al. 2012, Sonnentag et al. 2011). Other forms of remote sensing may also be available such as satellite images provided by MODIS.
Frequency of monitoring/recording	Measurements must be collected frequently during the growing season; measurements during the non-growing seasons are also required
QA/QC procedures	See Methods Module (MM-W/RC)

Photosynthesis PEPRMT Model Parameters, Descriptions, and Values

PARAMETERS, STATE VARIABLES, AND DRIVER VARIABLES	DESCRIPTION	VALUE
PARAMETERS		
ε	Light use efficiency (g C MJ^{-1})	0.94
H_a	Activation energy for photosynthesis (kJ mol^{-1})	21.5
H_d	Inhibition of photosynthesis at high temperatures (kJ mol^{-1})	110
R	Universal gas constant	0.00831
T_{opt}	Optimum temp for photosynthesis	25ºC
STATE VARIABLES		
NEE	Net ecosystem exchange CO_2 (µmol m^{-2} s^{-1})	
GPP	Gross ecosystem primary productivity (µmol m^{-2} s^{-1})	
DRIVER VARIABLES		
Air temperature	ºC	
PAR	Photosynthetically active radiation (µmol m^{-2} s^{-1})	
LAI	Leaf area index	

Respiration PEPRMT Model Parameters, Descriptions, and Values

PARAMETERS, STATE VARIABLES, AND DRIVER VARIABLES	DESCRIPTION	VALUE
PARAMETERS		
kM_{labile}	Michaelis-Menten constant for labile C (g C cm-3 soil)	1.7 x 10-6
kM_{SOC}	Michaelis-Menten constant for SOC (g C cm-3 soil)	6.3 x 10-6
α_{labile}	Pre-exponential factor for labile C (µmol C cm-3 soil s-1)	2
α_{SOC}	Pre-exponential factor for SOC (µmol C cm-3 soil s-1)	2
Ea_{labile}	Activation energy for labile C (kJ mol-1)	18
Ea_{SOC}	Activation energy for SOC (kJ mol-1)	17.8
C_{SOC}	Initial SOC pool (mol C m-3)	measured
STATE VARIABLES		
R_{eco}	Ecosystem respiration (µmol m^{-2} s^{-1})	
C_{SOC}	SOC pool	
DRIVER VARIABLES		
Air temperature	ºC	
PAR	Photosynthetically active radiation (µmol m-2 s-1)	
WT	Water table height	
GPP	Gross ecosystem primary productivity (µmol m-2 s-1)	

CH_4 PEPRMT Model Parameters, Descriptions, and Values

PARAMETERS, STATE VARIABLES, AND DRIVER VARIABLES	DESCRIPTION	VALUE
	PARAMETERS	
kM_{labile}	Michaelis-Menten constant for labile C (g C cm^{-3} soil)	2.3 x 10^{-5}
kM_{SOC}	Michaelis-Menten constant for SOC (g C cm^{-3} soil)	1.7 x 10^{-5}
kM_{CH4}	Michaelis-Menten constant for CH_4 oxidation (g C cm^{-3} soil)	2.3 x 10^{-5}
α_{labile}	Pre-exponential factor for labile C (µmol C cm^{-3} soil s^{-1})	6 x 10^{8}
α_{SOC}	Pre-exponential factor for SOC (µmol C cm^{-3} soil s^{-1})	6 x 10^{7}
a_{CH4}	Pre-exponential factor for CH_4 oxidation (µmol C cm^{-3} soil s^{-1})	6 x 10^{7}
Ea_{labile}	Activation energy for labile C (kJ mol^{-1})	71.1
Ea_{SOC}	Activation energy for SOC (kJ mol^{-1})	67.1
Ea_{CH4}	Activation energy for CH_4 oxidation (kJ mol^{-1})	75.4
C_{SOC}	Initial SOC pool (mol C m^{-3})	measured
k_{plant}	Gas transfer velocity through plants (Kettunen et al. 2003)	0.24 m d^{-1}
V_{oxi}	Fraction of CH_4 oxidized during plant transport	0.35
k_{hydro}	Gas transfer velocity through water (Poindexter et al. 2016)	0.04 m d^{-1}

STATE VARIABLES

R_{CH4}	CH_4 production (µmol m^{-2} d^{-1})	
O_{CH4}	CH_4 oxidation (µmol m^{-2} d^{-1})	
N_{CH4}	Net CH_4 emission (µmol m^{-2} d^{-1})	
C_{CH4}	Soil CH_4 pool	

DRIVER VARIABLES

Air temperature	ºC	
PAR	Photosynthetically active radiation (µmol m^{-2} s^{-1})	
WT	Water table height	
GPP	Gross ecosystem primary productivity (µmol m^{-2} s^{-1})	

APPENDIX D: REFERENCES

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WR Methodology Module

Wetland Restoration Methodology Framework (WR-MF)

I. GENERAL GUIDANCE

A. Scope

This 'Wetland Restoration Methodology Framework' is the basic structure of a modular methodology. It provides the generic functionality of the methodology, which frames pre-defined modules and tools that perform a specific function. It constitutes, together with the modules and tools it calls upon, a complete wetland restoration offset project baseline and monitoring methodology.

The modules and tools called upon in this document are applicable to quantify greenhouse gas (GHG) removals and emission reductions from wetland restoration (WR) activities, including wetland management, implemented on degraded forested and nonforested wetlands in the Mississippi Delta ranging from fresh to saline conditions. The modular approach is used to simplify the methodology, including allowing accounting for projected wetland loss in baseline scenario and project activities that include hydrologic management to enhance CO_2 removals.

This WR carbon offset methodology does not attempt to provide guidance or applicability criteria for wetland restoration in general, a diverse activity that requires the expertise of wetland ecologists and other experts to be designed and implemented successfully. The methodology only attempts to provide requirements for the quantification and crediting of carbon offset credits by WR activities that meet its applicability conditions. The methodology assumes the Project Proponent has or engages the necessary expertise, and requires that WR activities implemented under this methodology comply with all applicable regulations.

B. Sources

The methodology structure and text have been adapted from the following methodologies:

AR-AM0002/Version 03

AR-ACM0001/ Version 05

AR-AMS0003/ Version 01

ACR IFM Methodology Sept 2010

ACR REDD Methodology Modules

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C. Definitions and Acronyms

ACR	American Carbon Registry
A/R	afforestation and or reforestation
ARR	afforestation, reforestation, and revegetation
Baseline	most likely management scenario in the absence of the project
C	carbon
CO_2	carbon dioxide
CO_2-e	carbon dioxide equivalent
CF	carbon fraction
CH_4	methane
d.m.	dry matter
DBH	diameter at breast height
ERT	emission reduction ton
Ex-ante	'before the event' or predicted response of project activity
Ex-post	'after the event' or measured response of project activity
GHG	greenhouse gas
GIS	geographic information system
GPS	global positioning system
Historical reference period	the historical period prior to the project Start Date that serves as the source of data for defining the baseline
H	tree height
i	used to represent a stratum
Leakage	any change in carbon stocks or greenhouse gas emissions that occur outside a project's boundary (but within the same country) that is measurable and attributable to the project activity
Module	Component of a methodology that can be applied on its own to perform a specific task
Most likely	the scenario having the highest probability of occurrence

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N_20	nitrous oxide
QA	quality assurance
QC	quality control
Stratification	a standard statistical procedure to decrease overall variability of carbon stock estimates by grouping data taken from environments with similar characteristics (e.g., vegetation type; age class; hydrology; elevation)
Tool	Guideline or procedure for performing an analysis (e.g., "Tool for testing significance of GHG emissions in A/R CDM project activities) or to help use or select a module or methodology
WR	wetland restoration and management activities that are implemented to increase carbon sequestration and/or prevent/reduce GHG emissions

D. Modules and tools

This framework uses the following modules and tools:

Carbon Pool Modules:

CP-TB	Estimation of carbon stocks of living trees
CP-S	Estimation of carbon stocks of wetland soils

Baseline Modules:

BL-WR	Estimation of baseline carbon stock changes from WR
BL-WR-WL	Estimation of baseline carbon stock changes from WR including projected wetland loss for the baseline scenario
BL-WR-HM	Estimation of baseline carbon stock changes from WR where the project activity includes hydrologic management
BL-WR-HM-WL	Estimation of baseline carbon stock changes from WR where the project activity includes hydrologic management as well as projected wetland loss for the baseline scenario

Emissions Modules:

E-E	Estimation of greenhouse gas emissions
E-FFC	Estimation of emissions from fossil fuel combustion

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Project Scenario Modules:

PS-WR	Estimation of project scenario carbon stock changes and greenhouse gas emissions from WR
PS-WR-HM	Estimation of project scenario carbon stock changes and greenhouse gas emissions from WR with hydrologic management

Miscellaneous Modules:

X-UNC	Estimation of uncertainty

Tools:

T-DEG	"Tool for the identification of degraded or degrading lands for consideration in implementing CDM A/R project activities (Version 1)"
T-SIG	"Tool for testing significance of GHG emissions in A/R CDM project activities (Version 1);"
T-RISK	"ACR Tool for Risk Analysis and Buffer Determination."
T-PERM	"(VCS) AFOLU Non-Permanence Risk Analysis and Buffer Determination"
T-PLOTS	"Calculation of the number of sample plots for measurements within A/R CDM project activities."

All the above-mentioned tools are available at: www.americancarbonregistry.org, http://cdm.unfccc.int/Reference/tools/index.html and http://www.v-c-s.org/VCSv3.html.

Wetland restoration projects applicable under the Methodology Framework are divided into two broad activity types: WR activities that are limited to assisted natural regeneration, seeding, or tree planting; and WR activities that include a hydrologic management component. Under both activity types, Project Proponents may choose a conservative baseline scenario that assumes a constant wetland area within the project boundary, or a projected wetland loss baseline scenario that includes wetland loss that would occur within the project boundary in the baseline over a 40-year Crediting Period. A single project may delineate project boundaries to include both activity types as well as both baseline scenarios.

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Table 1. Determination of when module/tool use is mandatory (M), conditional (C), or optional (O).

Determination	Module/Tool	Wetland Restoration	Wetland Restoration with Hydrologic Management
Always Mandatory	WR-MF	M	M
	T-DEG	M	M
	T-RISK / T-PERM	M	M
	X-UNC	M	M
Baselines	BL-WR	M	N/A
	BL-WR-WL	O	N/A
	BL-WR-HM	N/A	M
	BL-WR-HM-WL	N/A	O
Pools	CP-TB	C[1]	C[21]
	CP-S	O	O
Emissions	E-E	N/A	C[3]
	E-FFC	C[4]	C[5]
Project Scenario	PS-WR	M	N/A
	PS-WR-HM	N/A	M

M Modules marked with an M are mandatory: the indicated modules and tools must be used.

C Modules marked with a C are conditional: the modules must be used under specific scenarios.

O Modules marked with an O are optional: wetland loss may be included or excluded in the baseline. The indicated pools and sources can be included or excluded as decided by the project, but if included in the baseline they must also be included in the with-project scenario and be monitored accordingly.

E. Applicability Conditions

This WR Methodology Framework is a compilation of modules and tools that together define the project activity and necessary methodological steps. By choosing the appropriate modules, a project-specific methodology can be constructed. The justification of the choice of modules and why they are applicable to the proposed project activity shall be given in the GHG Project Plan.

This methodology framework applies to private individuals and businesses, as well as public entities (i.e., county, state, federal, tribal, etc.) provided the Project Proponents demonstrate eligibility of project activities, and clear land and offsets title documentation.

All definitions, eligibility requirements, and other criteria of the ACR Standard and ACR Forest Carbon Project Standard shall apply. This includes the definitions of "forest", Afforestation/Reforestation (AR), Improved Forest Management (IFM), and Reduced Emissions from Deforestation and Degradation (REDD).

[1] If project activities include planting of woody biomass this module must be used.
[2] If project activities include planting of woody biomass this module must be used.
[3] If project activities include hydrologic management this module must be used.
[4] If project activities include moving sediment this module must be used.
[5] If project activities include moving sediment this module must be used.

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Wetland restoration is unique, but the WR activities covered by this methodology are eligible under three broad categories of AR, IFM and REDD in the ACR Forest Carbon Project Standard, as follows:

- WR will qualify under the AR category where project lands in the baseline do not meet the "forest" definition per the ACR Forest Carbon Project Standard, but project planting activities target the eventual establishment of a forest to increase carbon stocks.
    - Note however that in cases where the WR activity constitutes re-vegetation and the project lands may not, as a result of the WR activity, over the duration of the Crediting Period ever reach the "forest" threshold of 10% tree cover, as in the case of herbaceous wetlands, the project activity is allowed under the AR category as long as carbon stocks increase beyond the baseline case.
- Where project lands as of the project Start Date already meet the applicable "forest" definition due to percent tree cover or other factors, and will continue to constitute "forest" in the project scenario, WR activities qualify under the IFM category. The IFM project activity will include activities to increase carbon stocks by 1) assisted natural regeneration, seeding, or tree planting; 2) through hydrologic management; or 3) through a combination of these activities.
    - Note that project lands may or may not have been actively managed for forest products prior to the Start Date, and cannot be actively managed for forest products in the project scenario (since timber harvest is not allowed per the applicability conditions below).
- Project Proponents may choose to select modules to account for projected wetland loss in the baseline scenario. Project wetland loss in the baseline may or may not cause the project lands to fall below the "forest" thresholds. Such activities qualify under the REDD category, noting that:
    - Where project lands constitute "forest" as of the Start Date, in the baseline scenario are projected to fall below the "forest" threshold (including converting to open water), and in the project scenario are prevented from falling below the "forest" threshold, such WR activities constitute Reduced Emissions from Deforestation (i.e. avoided conversion from forest to non-forest).
    - Where project lands constitute "forest" as of the Start Date, in the baseline scenario are projected to degrade but not necessarily fall below the "forest" threshold, and in the project scenario degradation is reduced, such WR activities constitute Reduced Emissions from Degradation.
    - Where project lands do not constitute "forest" as of the Start Date, in the baseline scenario are projected to degrade and/or convert to open water, and in

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the project scenario degradation is reduced, such WR activities constitute Reduced Emissions from Degradation.

Specific applicability conditions exist for each module and must be met for the module to be used. Use of the methodology framework is subject to the following applicability conditions:

1) All Activity Types

- This methodology is only applicable for forested and non-forested wetlands in the Mississippi Delta ranging from fresh to saline conditions. Wetlands are defined as having one or more of the following three attributes: (1) at least periodically, the land supports predominantly hydrophytes; (2) the substrate is predominantly undrained hydric soil; and/or (3) the substrate is non-soil and is saturated with water or covered by shallow water at some time during the growing season of each year[6].
- Project activities must conform to all applicable policies and legislation relevant to wetland restoration.
- Project activities must not be required under Section 404 of the Clean Water Act to mitigate onsite or offsite impacts to wetlands.
- The WR project activity is implemented on degraded wetlands that are expected to remain degraded or to continue to degrade in the absence of the project, and hence the land cannot be expected to revert to a non-degraded state without human intervention. The tool T-DEG shall be applied.
- Per the ACR Forest Carbon Project Standard, Project Proponents shall document that project lands were not cleared of trees during the 10 years preceding the project Start Date in order to implement a WR project. This exclusion does not apply in the case of natural disturbances.
- The baseline is defined as existing or historical changes in carbon stocks of the carbon pools within the project boundary, where the land would remain degraded in the absence of the project activity. Baseline scenarios may fall into the following categories:
    - Conservative baseline scenario: uses the degraded carbon sequestration rate determined just prior to Start Date or that would have occurred in the absence of the project activity. This baseline assumes a constant wetland area in the baseline scenario;
    - Projected wetland loss baseline scenario: (1) uses the degraded wetland carbon sequestration rate that would have occurred in the absence of the project

[6] Cowardin, L.M., V. Carter, F. C. Golet, and E. T. LaRoe. 1979. Classification of Wetlands and Deepwater habitats of the United States. FWS/OBS-79/31, U.S. Fish and Wildlife Service, Washington, DC. 103 pp.

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activity, (2) incorporates loss of sequestration ability due to wetland loss that would occur over a 40-year Crediting Period if no project activity were to take place, as well as (3) emissions that would have occurred during wetland loss due to decomposition of organic matter.

- Drainage of wetland soils is not allowed.
- Not more than 10% of the project area may be disturbed as result of project planting.
- The project activity does not lead to a shift of pre-project activities outside the project boundary above the *de minimis* threshold (e.g., the land under the proposed project activity can continue to provide at least the same amount of goods and services as in the absence of the project activity).
- WR activities may include wetland management activities to increase net wetland sequestration as long as activities do not cause deleterious impacts or diminish the GHG sequestration function of habitat outside the project area.
- The project must demonstrate an increase in net wetland sequestration above the baseline condition by the end of the Crediting Period.
- Controlled burning is allowed to assist in the control of exotic or problematic species but the SOC pool must be monitored.
- Activities that involve the use of natural resources within the project boundary that do not lead to deforestation or further degradation are permitted (e.g., fishing, hunting, etc.). Harvesting of wood products is not allowed.

2) Wetland Restoration with Hydrologic Management

- For project activities involving hydrologic management the applicability conditions under 1) All Activity Types must be met, in addition to the following applicability conditions:
- Hydrologic management can be implemented to provide suitable conditions for wetland vegetative productivity and carbon sequestration. Examples of eligible hydrologic management project activities include:

  a. Diversion of river water (e.g., Mississippi River or other) into wetlands;

  b. Introduction of nonpoint source runoff (e.g., agricultural, stormwater) into wetlands;

  c. Discharge of treated municipal effluent into wetlands (e.g., wetland assimilation).

  d. Outfall management to maximize sheet flow and minimize impounded or stagnant conditions.

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- Project activities that increase emissions beyond the baseline scenario must be accounted for. Refer to BL-WR-HM and BL-WR-HM-WL for detailed procedures to determine how to account for GHG emissions related to hydrologic management and when they may be excluded.

II. ASSESSMENT OF NET GREENHOUSE GAS EMISSION REDUCTIONS

General

The methodological procedure for the assessment is implemented by applying the following eight steps:

Step 0. Identification of the most plausible project activity baseline

Step 1. Definition of the project boundaries

Step 2. Demonstration of additionality

Step 3. Development of monitoring plan

Step 4. Estimation of baseline carbon stock changes and GHG emissions

Step 5. Estimation of total net GHG emissions reductions (project minus baseline and leakage)

Step 6. Calculation of uncertainty

Step 7. Assessment of reversal risk

Step 8. Calculation of ERTs

The same steps shall be followed *ex-ante* and *ex-post.* For parameters that will be monitored subsequent to project initiation, *ex-ante* guidance is given in the relevant modules CP-S, CP-TB, E-E, and E-FFC.

Step 0. Identification of the most plausible project activity

Use the following decision tree to identify the appropriate ACR-eligible WR project activity baseline. The decision tree shall be used to provide a broad indication of likely baseline type and applicability. Ultimately the relevant baseline modules (BL-WR – wetland restoration; BL-WR-WL – wetland restoration including projected wetland loss; BL-WR-HM – wetland restoration with hydrologic management; BL-WR-HM-WL – wetland restoration with hydrologic management including projected wetland loss) must be applied, complying with the relevant applicability conditions and criteria given in those modules.

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Will hydrologic management be implemented as part of the project activity?			
NO		**YES**	
Will wetland loss be included in the baseline scenario?		Will wetland loss be included in the baseline scenario?	
NO	**YES**	**NO**	**YES**
BL-WR	BL-WR-WL	BL-WR-HM	BL-WR-HM-WL

A project can include areas subject to different activities/baselines (e.g., Area A = BL-WR; Area B = BL-WR-WL; Area C = BL-WR-HM-WL). In such cases, the areas that are eligible for different categories shall be clearly delineated in the GHG Project Plan and the procedures outlined below applied to each of them separately.

Step 1. Definition of the project boundaries

The following categories of boundaries shall be defined:

a. The geographic boundaries relevant to the project activity;

b. The temporal boundaries;

c. The carbon pools that the project will consider; and

d. The sources and associated types of greenhouse gas emissions that the project will affect.

a. <u>Project Geographic Boundary</u>

The Project Proponents must provide a detailed description of the geographic boundary of project activities referred to as the 'project boundary'. Note that the project activity may contain more than one discrete area of land, but each area must meet the project eligibility requirements. Information to delineate the project boundary may include:

- USGS topographic map or property parcel map where the project boundary is recorded for all areas of land. Provide the name of the project area (e.g., compartment number, allotment number, local name); and a unique ID for each discrete parcel of land;
- Aerial map (e.g. orthorectified aerial photography or georeferenced remote sensing images);

Geographic coordinates for the project boundary, total land area, and land holder and user rights. Depending on the WR category further boundary requirements may be detailed in the baseline module.

The geographic boundaries of a WR project are fixed (*ex-ante*) and thus cannot change over the Crediting Period (40 years), however, the area of wetlands within the project boundary can change, with 'change' defined as transition from vegetated wetlands to open water. Where

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multiple baselines exist (BL-WR; BL-WR-WL; BL-WR-HM; BL-WR-HM-WL) there shall be no overlap in boundaries between areas appropriate to each of the baselines. Thus, two project types cannot occur on the same piece of land.

b. Temporal Boundaries

Generally, baseline wetland management results in the continued loss of wetlands (see Wetland Loss section in baseline modules BL-WR-HM-WL & BL-WR-WL). Wetlands are unique from forestry and silviculture in that baseline wetlands are not actively managed by landowners due to high costs and lack of technical expertise for wetland restoration. Therefore, baseline management is not subject to change and will not need to be incorporated into the baseline.

Project Start Date: Projects with a Start Date of November 1, 1997, or later are eligible to receive offsets retroactively to the Start Date[7]. The project Start Date is defined as the day Project Proponents began land management activities to increase carbon stocks and/or reduce GHG emissions. Projects with a Start Date earlier than November 1, 1997, may be approved on a case-by-case basis. Project Proponents must provide documentation that GHG mitigation was an objective from project inception in order to receive offsets retroactively for pre-1997 projects.

Crediting Period: A 40-year Crediting Period has been selected for this methodology, based on the allowed Crediting Period for AR in the Forest Carbon Project Standard. The minimum Project Term, also 40 years for all forest carbon projects, begins on the Start Date (not the first or last year of crediting). Baseline revisions at 40-year intervals similar to AR requirements will ensure baseline validity because baseline wetland loss can be more accurately predicted using longer intervals that reveal long-term land change trends.

Time of Monitoring Event: This is the period of interest or evaluation. It can be the time in years elapsed since the Project Start Date and the date of data acquisition for carbon stock assessment, or the interval between two carbon stock assessments (e.g., 5y to 10y).

c. Pools and Sources

Tables 2, 3 and 4 shall be followed in determining the GHG assessment boundary, along with the guidance in the ACR *Forest Carbon Project Standard,* Chapter 2. Exclusion of carbon pools and emission sources is allowed subject to considerations of conservativeness and significance testing. Pools or sources may always be excluded if conservative, i.e. exclusion will tend to underestimate net GHG emission reductions/removal enhancements. Pools or sources can be neglected (i.e., counted as zero) if application of the tool T-SIG indicates that the source is insignificant, provided that all sources, sinks and pools determined to be insignificant and

[7] American Carbon Registry, 2010. American Carbon Registry Forest Carbon Project Standard, version 2.1. Winrock International, Little Rock, Arkansas.

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excluded from accounting represent less than 3% of the *ex ante* calculation of emission reductions/removal enhancements (per ACR *Forest Carbon Project Standard*).

Table 2. Carbon Pools

Carbon pools	Included / Optional / Excluded	Justification / Explanation of choice
Aboveground biomass carbon	**Included**	Major carbon pool subjected to project activity. This methodology quantifies the aboveground biomass of trees.
Belowground biomass carbon	**Included**	This is the belowground biomass of trees, calculated as a ratio of aboveground biomass, and can only be included if SOC is not measured.
Harvested wood products	**Excluded**	Harvesting of wood products is ineligible in this version of the methodology.
Dead wood	**Excluded**	This pool is conservatively omitted.
Litter / Surface debris	**Excluded**	This pool is conservatively omitted.
Soil organic carbon (SOC)	**Included**	Carbon pool subjected to the project activity. SOC stock is expected to increase due to the implementation of project activity.

Table 3. Wetland Emission Sources

Gas	Source	Included / excluded	Justification / Explanation of choice
CO_2	**Decomposition**	**Included/Excluded**	This source can be included if a baseline is selected that includes projected wetland loss, otherwise can be conservatively omitted.
CH_4	**Decomposition/ Methanogenesis**	**Included/ excluded**	Shall be included if this source in the project scenario is significantly greater than baseline scenario, otherwise can be conservatively omitted.
N_2O	**Decomposition/ Denitrification**	**Included/ excluded**	Shall be included if this source in the project scenario is significantly greater than baseline scenario, otherwise can be conservatively omitted.

Table 4. Leakage and Project Activity Emission Sources

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Leakage and Project Activity Emission Source	Included / optional/ excluded	Justification / Explanation of choice
Activity-Shifting ***Site Preparation***	**Excluded**	Negligible. The potential emission source from fossil fuel combustion in the vehicles used for the transportation of seedling, labor, and site preparation is considered insignificant.
Site / Project Specific Activity ***Hydrologic Management***	**Excluded**	Negligible. The potential emission source from fossil fuel combustion due to water management activities is considered insignificant.
Site / Project Specific Activity ***Moving Sediment***	**Included/ excluded**	Can be neglected if the restoration activity does not include moving sediments or fossil fuel combustion emissions are determined not to be significant using module T-SIG.
Harvesting	**Excluded**	Negligible. The GHG Project Plan shall demonstrate that at least the same amount of goods and services will continue to be provided (e.g., alligator egg harvesting, fisheries, and hunting).
Crops	**Excluded**	This methodology is not applicable if agricultural or pastoral activities will be displaced to other locations.
Livestock	**Excluded**	This methodology is not applicable if livestock activities will be displaced to other locations.
Market Effects ***Timber***	**Excluded**	Not applicable because timber harvest is not allowed.
Fuelwood	**Excluded**	Not applicable because harvesting of fuelwood is not allowed.

d. Leakage and Project Activity Emission Sources

According to the Applicability Conditions, this methodology is not applicable if leakage exceeds *de minimis* levels. Wetlands are distinct from other terrestrial sequestration types in that there is generally no activity shifting to other locations, such as with silviculture or agriculture, when wetlands are restored. Healthy wetlands increase the production of goods supplied to a market, such as fisheries, game hunting, or hurricane protection, without a corresponding reduction in the demand for that good. Furthermore, degraded wetlands in the Mississippi Delta are not a source of fuel wood.

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The project activity will not result in a reduction of wetland restoration activities or increase wetland loss outside of the project boundary. This methodology is not applicable if livestock or other pastoral activities will be displaced to other locations

The potential project activity emission source from fossil fuel combustion due to water management activities is considered insignificant. Most systems such as river diversions are gravity fed, while other systems will require equivalent fossil fuel combustion to reroute existing flows. Fossil fuel combustion in the vehicles used for the transportation of seedlings, labor, and site preparation is also considered insignificant. Project activities that include moving sediments may be a significant source of emissions due to fossil fuel combustion. Fossil fuel combustion emission sources due to moving of sediments shall be quantified using module E-FFC if determined to be significant using module T-SIG.

Step 2. Demonstration of Additionality

The baseline scenario generally results in the continued loss of wetlands. Project Proponents must demonstrate that the wetland restoration project is not common practice per the Practice-based Performance Standard defined below. The restoration project must not be required to mitigate onsite or offsite impacts to wetlands under Section 404 of the Clean Water Act.

Emission reductions from the project must be additional, or deemed not to occur in the business-as-usual scenario. Assessment of the additionality of a project will be made based on passing the two tests cited below. These two tests require the Project Proponents to demonstrate that the project activity is surplus to regulations, and reduces emissions below the level established, through the practice-based performance standard as defined below, to represent common practice or "business-as-usual".

Project Proponents utilizing this methodology should consult the latest version of the ACR Standard, which may be updated periodically. At the time of the drafting of this methodology, the two additionality tests include:

1. Regulatory Surplus Test, and
2. Practice-based Performance Standard

Further guidance on these tests is given below.

TEST 1: Regulatory Surplus Test

In order to pass the regulatory surplus test, a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect now, or as of the

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project Start Date, that directly or indirectly affect the credited GHG emissions associated with a project.

The Project Proponents must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated with wetland restoration.

TEST 2: Practice-based Performance Standard

An assessment of the causes and consequences of wetland loss and management options for protection and restoration, based on national and regional information from various government agencies (federal, state, local), academic and research institutions as well as environmental NGOs, demonstrates that the percentage of land building (including natural land building and wetland restoration activities) is approximately 15% or less of the area of persistent wetland loss that is occurring in Louisiana.[8] Because wetland restoration is not common practice by landowners, wetland restoration projects using this methodology are deemed "beyond business as usual" and therefore additional.

Projects that meet the eligibility criteria for this methodology can use the performance standard to demonstrate additionality without providing additional implementation barrier analysis. Projects that are certified under this version of the methodology do not need to reassess additionality with each verification during the 40-year Crediting Period. However, the following common practice assessment and the applicability of the practice-based performance standard will be reassessed periodically after significant changes to the market, wetland management, or, at a minimum, every 10 years. Future common practice assessments should differentiate between wetland restoration projects that occurred as emission reduction projects or as business-as-usual activities.

ACR reserves the right to review the common practice assessment as necessary to ensure additionality of future projects. All GHG Project Plans for new projects, and all applications for Crediting Period renewal on existing projects, shall apply the regulatory surplus and practice-based performance standard tests in the latest approved revision of this methodology in effect at the time of GHG Project Plan submission or application for Crediting Period renewal.

Common Practice Assessment for Wetland Restoration:

The approximately 2.8 million acres of coastal wetlands of the Mississippi River delta represent 37% of estuarine wetlands in the conterminous United States, but have 80% of the historic

[8] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

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wetland loss in the country, and 90% of the current wetland loss.[9,10] The U.S. Geological Survey (USGS) and others have been studying the rates and causes of this wetland loss for many years. Based on USGS data and analysis from a 2011 report documenting the land area change in coastal Louisiana from 1932 to 2010, it is estimated that the percentage of land building is approximately 15% or less of the area of persistent wetland loss that is occurring in Louisiana.[11]

Land loss in the delta is a result of the complex interactions of natural and human-induced processes. The Mississippi delta was formed over the past 6,000-7,000 years as a series of overlapping delta lobes fed by river distributaries.[12,13] In the past, seasonal flooding of the Mississippi River deposited large amounts of sediments and nutrients into the Mississippi River delta, compensating for subsidence by mineral matter deposition and organic matter production.[14] There was an increase in wetland area in active deltaic lobes and wetland loss in abandoned lobes, but there was an overall net increase in the area of wetlands over the past several thousand years. The construction of flood-control levees and closure of distributary channels began soon after colonization of New Orleans by the French in 1719,[15,16,17] and by mid-20th century the Mississippi River delta was almost completely separated from the river.[18,19,20] Since that time there has been massive amounts of wetlands lost irrespective of any "no net loss policy", primarily due to levee and canal construction that caused

[9] Louisiana Department of Natural Resources (LDNR), 1998. Coast 2050: Toward a Sustainable Coastal Louisiana. Louisiana Coastal Wetlands Conservation and Restoration Task Force and the Wetlands Conservation and Restoration Authority. Louisiana Department of Natural Resources, Baton Rouge, LA, USA.

[10] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

[11] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

[12] Roberts, H.H., 1997. Dynamic changes of the holocene Mississippi river delta plain: the delta cycle. Journal of Coastal Research 13: 605-627.

[13] Day, J.W., D.F. Boesch, E.J. Clairain, G.P. Kemp, S.B. Laska, W.J. Mitsch, K. Orth, H. Mashriqui, D.J. Reed, L. Shabman, C.A. Simenstad, B.J. Streever, R.R. Twilley, C.C. Watson, J.T. Wells, and D. F. Whigham. 2007. Restoration of the Mississippi delta: lessons from hurricanes Katrina and Rita. Science 315: 1679-1684.

[14] Day, J.W., D.F. Boesch, E.J. Clairain, G.P. Kemp, S.B. Laska, W.J. Mitsch, K. Orth, H. Mashriqui, D.J. Reed, L. Shabman, C.A. Simenstad, B.J. Streever, R.R. Twilley, C.C. Watson, J.T. Wells, and D. F. Whigham. 2007. Restoration of the Mississippi delta: lessons from hurricanes Katrina and Rita. Science 315: 1679-1684.

[15] Boesch, DF (1996) Science and management in four U.S. coastal ecosystems dominated by land-ocean interactions. Journal of Coastal Conservation 2:103-114

[16] Welder, FA (1959) Processes of deltaic sedimentation in the lower Mississippi River. Louisiana State University, Coastal Studies Institute Technical Report 84, 56p

[17] Colten, C. (ed.) 2000. Transforming New Orleans and its Environs. University of Pittsburgh Press, Pittsburgh, PA, USA.

[18] Kesel, RH (1988) The decline in the suspended load of the Lower Mississippi River and its influence on adjacent wetlands. Environmental and Geological Water Science 11:271-281

[19] Kesel, RH (1989) The role of the lower Mississippi River in wetland loss in southeastern Louisiana, USA. Environmental and Geological Water Science 13:183-193

[20] Mossa, J (1996) Sediment dynamics in the lowermost Mississippi River. Engineering Geology 45:457-479

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impoundment, sediment and nutrient deprivation, land subsidence, and saltwater intrusion.[21,22,23,24,25]

In 2011, the USGS released a comprehensive analysis of historical trends and rates of land area change in coastal Louisiana based on land and water classifications from 17 data sets.[26] The goal of the study was to provide updated estimates of persistent land changes and historical land change trends for coastal Louisiana and for each hydrologic basin, as defined by the Coastal Wetlands Planning, Protection and Restoration Act Program (n.d.), for the 1932-2010 period of record.[27] The analyses of landscape change presented in the report use historical surveys, aerial data, and satellite data to track landscape changes. The data sets were derived from multiple sources including (1) historical survey data (1932); (2) National Wetlands Inventory (NWI) data based on aerial photography (1956); (3) Landsat Multi-Spectral Scanner (MSS) data (1973-1979); and (4) Landsat Thematic Mapper (TM) satellite imagery classification into land and water categories (1985-2010). Summary data were presented for 1932–2010 and trend data were presented for 1985–2010 because of concerns over the comparability of the 1932 and 1956 datasets that used survey and aerial data, while the later datasets were based on satellite imagery. Statistics were calculated of coastal land change based on isolated coastal regions that excluded fastlands (defined as developed, agricultural, and other protected areas).

The results show that the percentage of land building ranged from 2-12% of persistent land loss[28] substantiating the argument that wetland restoration and avoided loss are not common practice or "business-as-usual" and wetland restoration under this methodology thus passes the performance standard test. The mapped dataset only identified areas of persistent and

[21] Barras, J.A., Beville, S., Britsch, D., Hartley, S., Hawes, S., Johnston, J., Kemp, P., Kinler, Q., Martucci, A., Porthouse, J., Reed, D., Roy, K., Sapkota, S., Suhayda, J., 2003. Historical and projected coastal Louisiana land changes: 1978-2050. USGS Open File Report 03-334, 39 pp.

[22] Boesch, D.F., Josselyn, M.N., Mehta, A.J., Morris, J.T., Nuttle, W.K., Simenstad, C.A., Swift, D., 1994. Scientific assessment of coastal wetland loss, restoration and management in Louisiana. J. Coastal Res. 20, 1-103.

[23] Salinas LM, DeLaune RD, Patrick WH (1986) Changes occurring along a rapidly submerging coastal area: Louisiana. Journal of Coastal Research 2:269-284

[24] Day, J.W., D.F. Boesch, E.J. Clairain, G.P. Kemp, S.B. Laska, W.J. Mitsch, K. Orth, H. Mashriqui, D.J. Reed, L. Shabman, C.A. Simenstad, B.J. Streever, R.R. Twilley, C.C. Watson, J.T. Wells, and D. F. Whigham. 2007. Restoration of the Mississippi delta: lessons from hurricanes Katrina and Rita. Science 315: 1679-1684.

[25] Turner, R. E., E. M. Swenson & J. M. Lee, 1994. A rationale for coastal wetland restoration through spoil bank management in Louisiana, USA. Environmental Management 18: 271-282.

[26] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

[27] Louisiana Coastal Wetlands Planning, Protection and Restoration Act Program, n.d., Coastal Louisiana basins: Louisiana Coastal Wetlands Planning, Protection and Restoration Act Program Web site. http://lacoast.gov/new/About/Basins.aspx.

[28] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

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consistent change. An area had to experience a change in land/water category that persisted for at least two time periods following the initial conversion before the area could be classified as "loss" or "gain". Rates of wetland loss have been decreasing from the high rates observed in the 1970's, though land building as a percentage of wetland loss has remained below 15%.[29] The Atchafalaya Delta Basin was the only area in coastal Louisiana showing increasing land area, but the rate of growth in this one basin is not sufficient to offset the losses coast wide, which have been as high as 40 square miles (mi^2) per year.[30] Coastal Louisiana has undergone a net change in land area of about -1,883 mi^2 from 1932 to 2010.[31,32,33,34,35,36,37,38] This net change in land area amounts to a decrease of about 25% of the 1932 land area.[39] Over 95% of this loss was wetland, primarily marsh, conversion to open water. Trend analyses from 1985 to 2010

[29] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

[30] Gagliano, S.M., Meyer-Arendt, K.J. and Wicker, K.M. 1981. Land loss in the Mississippi river deltaic plain. Transactions of the gulf coast association of geological societies 31:295-300.

[31] Barras, J.A., Beville, S., Britsch, D., Hartley, S., Hawes, S., Johnston, J., Kemp, P., Kinler, Q., Martucci, A., Porthouse, J., Reed, D., Roy, K., Sapkota, S., Suhayda, J., 2003. Historical and projected coastal Louisiana land changes: 1978-2050. USGS Open File Report 03-334, 39 pp.

[32] Britsch, L.D., and Dunbar, J.B., 1993, Land-loss rates-Louisiana coastal plain: Journal of Coastal Research, v. 9, p.324-338.

[33] Boesch, D.F., Josselyn, M.N., Mehta, A.J., Morris, J.T., Nuttle, W.K., Simenstad, C.A., Swift, D., 1994. Scientific assessment of coastal wetland loss, restoration and management in Louisiana. J. Coastal Res. 20, 1-103.

[34] Boesch DF, Shabman L, Antle LG, Day JW, Dean RG, Galloway GE, Groat CG, Laska SB, Luettich RA, Mitsch WJ, Rabalais NN, Reed DJ, Simonstad CA, Streever BJ, Taylor RB, Twilley RR, Watson CC, Wells JT, Whigham DF (2006) A New Framework for Planning the Future of Coastal Louisiana after the Hurricanes of 2005. Working Group for Post-Hurricane Planning for the Louisiana Coast, 48p

[35] Shafer GP, Wood WB, Hoeppner SS, Perkins TE, Zoller J, Kandalepas D (2009) Degadation of baldcypress-water tupelo swamp to marsh and open water in southeastern Louisiana, U.S.A.: An irreversible trajectory? Journal of Coastal Research 54: 152-165

[36] Barras, J.A.; Bourgeois, P.E., and Handley, L.R., 1994. Land Loss in Coastal Louisiana, 1956–1990. National Wetlands Research Center Open File Report 94-01. Lafayette, Louisiana: National Biological Survey.

[37] Chambers, J.L.; Conner, W.H.; Day, J.W.; Faulkner, S.P.; Gardiner, E.S.; Hughes, M.S.; Keim, R.F.; King, S.L.; McLeod, K.W.; Miller, C.A.; Nyman, J.A., and Shaffer, G.P., 2005. Conservation, Protection and Utilization of Louisiana's Coastal Wetland Forests. Final Report to the Governor of Louisiana from the Coastal Wetland Forest Conservation and Use Science Working Group. (special contributions from Aust, W.M.; Goyer, R.A.; Lenhard, G.J.; Souther-Effler, R.F.; Rutherford, D.A., and Kelso, W.E.), 121p. Available from: Louisiana Governor's Office of Coastal Activities, 1051 N. Third St. Capitol Annex Bldg, Suite 138 Baton Rouge, LA 70802. http://www.coastalforestswg.lsu.edu

[38] Barras, J.A., J.C. Bernier, and R.A. Morton. 2008. Land area change in coastal Louisiana - A multidecadal perspective (from 1956 to 2006). U.S. Geological Survey Scientific Investigations Map 3019, scale 1:250,000, 14 p. pamphlet.

[39] Louisiana Department of Natural Resources (LDNR), 1998. Coast 2050: Toward a Sustainable Coastal Louisiana. Louisiana Coastal Wetlands Conservation and Restoration Task Force and the Wetlands Conservation and Restoration Authority. Louisiana Department of Natural Resources, Baton Rouge, LA, USA.

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indicate a wetland loss rate of 16.57 mi^2 per year[40], which is equivalent to losing an area the size of a football field per hour.[41]

Wetland loss in coastal Louisiana is rapid despite current wetland restoration efforts. The USGS predicts that by 2050, with 'business as usual', there will be an additional 700 mi^2 of wetland loss if no substantial restoration is undertaken.[42,43] Sea level rise is anticipated to increase, causing increased saltwater intrusion and flooding, ultimately resulting in wetland loss.[44,45] Meanwhile, several studies of Mississippi River deltaic swamps indicate that many areas are in a state of deterioration, are not sustainable,[46,47,48,49,50,51] and exhibit little natural regeneration.[52,53] Without river reintroductions in the near future, as well as harnessing other

[40] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

[41] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet

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[43] Louisiana Department of Natural Resources (LDNR), 1998. Coast 2050: Toward a Sustainable Coastal Louisiana. Louisiana Coastal Wetlands Conservation and Restoration Task Force and the Wetlands Conservation and Restoration Authority. Louisiana Department of Natural Resources, Baton Rouge, LA, USA.

[44] Conner, W.H. and Day, J.W., Jr., 1988. Rising water levels in coastal Louisiana: implications for two coastal forested wetland areas in Louisiana. Journal of Coastal Research, 4, 589–596.

[45] Blum, M. and H. Roberts. 2009. Drowning of the Mississippi Delta due to insufficient sediment supply and global sea-level rise. Nature Geoscience. 2:488-491

[46] Conner, W.H. and Day, J.W., Jr., 1992. Water level variability and litterfall productivity of forested freshwater wetlands in Louisiana. American Midland Naturalist, 128(2), 237–245.

[47] Hoeppner, S.S., 2002. Feasibility and Project Benefits of a Diversion into the Degraded Cypress–Tupelo Swamp in the Southern Lake Maurepas Wetlands, Lake Pontchartrain Basin, Louisiana. Hammond, Louisiana: Southeastern Louisiana University, Master's thesis, 123p.

[48] Hoeppner, S.S.; Shaffer, G.P., and Perkins, T.E., 2008. Through droughts and hurricanes: tree mortality, forest structure, and biomass production in a coastal swamp targeted for restoration in the Mississippi River Deltaic. Forest Ecology and Management, 256, 937–948.

[49] Chambers, J.L.; Conner, W.H.; Day, J.W.; Faulkner, S.P.; Gardiner, E.S.; Hughes, M.S.; Keim, R.F.; King, S.L.; McLeod, K.W.; Miller, C.A.; Nyman, J.A., and Shaffer, G.P., 2005. Conservation, Protection and Utilization of Louisiana's Coastal Wetland Forests. Final Report to the Governor of Louisiana from the Coastal Wetland Forest Conservation and Use Science Working Group. (special contributions from Aust, W.M.; Goyer, R.A.; Lenhard, G.J.; Souther-Effler, R.F.; Rutherford, D.A., and Kelso, W.E.), 121p. Available from: Louisiana Governor's Office of Coastal Activities, 1051 N. Third St. Capitol Annex Bldg, Suite 138 Baton Rouge, LA 70802. http://www.coastalforestswg.lsu.edu

[50] Pezeshki, S.R.; DeLaune, R.D., and Patrick, W.H.J., 1990. Flooding and saltwater intrusion: potential effects on survival and productivity of wetland forests along the U.S. Gulf Coast. Forest Ecology and Management, 33/34, 287–301.

[51] Shaffer, G.P.; Perkins, T.E.; Hoeppner, S.S.; Howell, S.; Benard, T.H., and Parsons, A.C., 2003. Ecosystem Health of the Maurepas Swamp: Feasibility and Projected Benefits of a Freshwater Diversion. Final Report. Dallas, Texas: Environmental Protection Agency, Region 6, 95p.

[52] Conner, W.H. and Day, J.W., Jr., 1976. Productivity and composition of a bald cypress-water tupelo site and a bottomland hardwood site in a Louisiana swamp. American Journal of Botany, 63, 1354–1364.

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point and nonpoint sources of freshwater, many wetlands in coastal Louisiana will continue their trajectory towards open water.[54] Given favorable hydrologic and nutrient conditions, Baldcypress (*Taxodium distichum*) and Water Tupelo (*Nyssa aquatica*) seedlings can reach greater than 10 m heights within one decade. For example, a pilot planting of Baldcypress seedlings at the Caernarvon diversion has yielded trees over 10 m tall in a decade, and all of these resisted wind throw during the hurricanes of 2005.[55] However, even with sustainable water management, most swamps will need to be planted to establish tree growth since conditions for natural regeneration (i.e., several months of dry conditions) rarely occur anymore. In conclusion, if we are to reverse the trajectory of coastal wetland loss, we must find, and wisely use, point and nonpoint sources of freshwater to a much greater extent, as well as undertake large-scale tree plantings.[56]

Costs of Wetland Restoration:

Depending upon the extent of area included, the level of storm protection to communities, and the amount invested in the long-term sustainability of ecosystem services, the cost of restoration of the Mississippi Delta has been debated for the last ten years with estimates ranging from $10 billion for near-term restoration to $150 billion for restoration and protection. Costs for wetland restoration range from $8,000-$60,000 an acre depending on the restoration technique.[57] Past studies have found that restoration plans that address broad wetland loss throughout the Mississippi Delta are too expensive, requiring more recent restoration plans to focus on the most urgent problems.[58]

After the hurricanes of 2005, Congress directed the Secretary of the Army to develop a full range of risk reduction measures for South Louisiana including coastal restoration. This Louisiana Coastal Protection & Restoration (LACPR) plan estimates that it would take $543,000,000 per year, for a total "life-cycle cost" of $10.7 billion, to restore the coast using Mississippi River diversions, marsh restoration using dredged material, and shoreline

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[53] Shaffer, G.P.; Perkins, T.E.; Hoeppner, S.S.; Howell, S.; Benard, T.H., and Parsons, A.C., 2003. Ecosystem Health of the Maurepas Swamp: Feasibility and Projected Benefits of a Freshwater Diversion. Final Report. Dallas, Texas: Environmental Protection Agency, Region 6, 95p.

[54] Shafer GP, Wood WB, Hoeppner SS, Perkins TE, Zoller J, Kandalepas D (2009) Degadation of baldcypress-water tupelo swamp to marsh and open water in southeastern Louisiana, U.S.A.: An irreversible trajectory? Journal of Coastal Research 54: 152-165

[55] Krauss, K.W.; Chambers, J.L.; Allen, J.A.; Soileau, D.M., Jr., and DeBosier, A.S., 2000. Growth and nutrition of baldcypress families planted under varying salinity regimes in Louisiana, USA. Journal of Coastal Research, 16, 153–163.

[56] Boesch, D.F., M.N. Josselyn, A.J. Mehta, J. T. Morris, W.K. Nuttle, C.A. Simestad, and D.J.P. Swift, 1994. Scientific assessment of coastal wetland loss, restoration and management in Louisiana. Journal of Coastal Research, Special Issue No. 20.

[57] http://lacoast.gov/new/Projects/List.aspx

[58] U.S. Army Corps of Engineers (2009). Louisiana Coastal Protection and Restoration (LACPR) Final Technical Report. New Orleans District, Mississippi Valley Division, 292 pp.

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stabilization in strategic areas, with the proviso that these coastal measures are for hurricane risk reduction only, sustaining existing coastal landscape.[59]

Louisiana's Comprehensive Master Plan for a Sustainable Coast has recently estimated that between $20 and $50 billion (in present value dollars) will realistically be available for funding over the next 50 years, but acknowledge that a budget five times that size is needed.[60] The State of Louisiana has recently used surplus revenues to accelerate priority restoration projects, and is projecting a larger revenue stream starting in 2017 from the sale of mineral leases and royalty revenue from oil and gas exploration in the Gulf of Mexico. The state admits that there will be a funding gap between now and 2017 and is exploring ways to narrow the gap and expand the coastal program to address broad wetland loss.[61] A goal of the Louisiana Office of Coastal Protection and Restoration is to develop a wetland carbon sequestration program to leverage carbon finance to address the funding gap and to expand the coastal restoration program. In summary, the true cost to restore the Mississippi Delta is beyond the capacity of landowners and current government programs.[62] Constrained budgets will require limited funding to be directed towards priority restoration projects while Louisiana will continue to experience the majority of the nation's wetland loss.[63]

Step 3. Development of monitoring plan

Project Proponents shall include a single monitoring plan in the GHG Project Plan. For monitoring changes in wetland cover and carbon stock changes, the monitoring plan shall use the methods given in PS-WR or PS-WR-HM. All relevant parameters from the modules are to be included in the monitoring plan.

The monitoring plan shall address the following monitoring tasks, which should be standard headers in the monitoring plan:

- Revision of the baseline
- Monitoring of actual carbon stock changes and greenhouse gas emissions
- Estimation of *ex-post* net carbon stock changes and greenhouse gas emissions

[59] U.S. Army Corps of Engineers (2009). Louisiana Coastal Protection and Restoration (LACPR) Final Technical Report. New Orleans District, Mississippi Valley Division, 292 pp.

[60] http://coastal.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&nid=24&pnid=0&pid=28&fmid=0&catid=0&elid=0

[61] http://coastal.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&nid=24&pnid=0&pid=28&fmid=0&catid=0&elid=0

[62] Boesch, D.F., M.N. Josselyn, A.J. Mehta, J. T. Morris, W.K. Nuttle, C.A. Simestad, and D.J.P. Swift, 1994. Scientific assessment of coastal wetland loss, restoration and management in Louisiana. Journal of Coastal Research, Special issue No. 20.

[63] Couvillion, B.R., Barras, J.A., Steyer, G.D., Sleavin, William, Fischer, Michelle, Beck, Holly, Trahan, Nadine, Griffin, Brad, and Heckman, David, 2011, Land area change in coastal Louisiana from 1932 to 2010: U.S. Geological Survey Scientific Investigations Map 3164, scale 1:265,000, 12 p. pamphlet.

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For each of these tasks, the monitoring plan shall include the following sections:

a. Technical description of the monitoring task.

b. Data to be collected. The list of data and parameters to be collected shall be given in the GHG Project Plan.

c. Overview of data collection procedures.

d. Quality control and quality assurance procedure.

e. Data archiving.

f. Organization and responsibilities of the parties involved in all the above.

Step 4. Estimation of baseline carbon stock changes and greenhouse gas emissions

The baseline scenario is the carbon stock present immediately prior to site preparation, or the most likely carbon stock in the absence of project implementation. Baseline determination is defined from Paragraph 22 of the CDM A/R Modalities and Procedures as "existing or historical, as applicable, changes in carbon stocks in the carbon pools within the project boundary" where the land would remain degraded in the absence of the project activity.

Methods for estimating baseline carbon stock changes and greenhouse gas emissions are provided in the following modules:

- For wetland restoration using a conservative baseline scenario: BL-WR
- For wetland restoration including projected wetland loss in the baseline scenario: BL-WR-WL
- For wetland restoration with hydrologic management project using a conservative baseline scenario: BL-WR-HM
- For wetland restoration with hydrologic management that includes projected wetland loss in the baseline scenario: BL-WR-HM-WL

A description of how the baseline scenario is identified and the description of the identified baseline scenario shall be given in the GHG Project Plan. The results of the estimations shall be presented in the GHG Project Plan.

Step 5. Estimation of total net greenhouse gas emissions reductions (project minus baseline and leakage)

The total net greenhouse gas emissions reductions of the WR project activity are calculated as follows:

$$C_{ACR,t} = (\Delta C_{ACTUAL} - \Delta C_{BSL}) * (1\text{-}LK) \quad (1)$$

where:

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$C_{ACR,t}$ Total net greenhouse gas emission reductions at time t; t CO_2-e

ΔC_{ACTUAL} Cumulative total of the carbon stock changes and greenhouse gas emissions under the project scenario up to time *t;* t CO_2-e (from PS-WR, or PS-WR-HM)

ΔC_{BSL} Cumulative total of the carbon stock changes and greenhouse gas emissions under the baseline scenario up to time *t;* t CO2-e (from an individual baseline, or the sum of the following baselines if the project includes more than one baseline type: BL-WR, BL-WR-WL, BL-WR-HM, BL-WR-HM-WL)

LK Cumulative total of the carbon stock changes and greenhouse gas emissions due to leakage up to time *t;* t CO_2-e; LK must equal zero for this methodology to be used

Step 6. Calculation of uncertainty

Project proponents shall use X-UNC to combine uncertainty information and determine an overall project uncertainty estimate of the total net GHG emissions reductions. If calculated total project uncertainty (UNC) in module X-UNC exceeds 10% at the 90% confidence level, then C_{ACR} calculated in equation (1) shall be adjusted as follows:

$$Adjusted_C_{ACR,t} = C_{ACR,t} * (100\% - UNC + 10\%) \quad (2)$$

where:

*Adjusted_*$C_{ACR,t}$ Cumulative total net GHG emission reductions at time *t* adjusted to account for uncertainty; t CO_2-e

$C_{ACR,t}$ Cumulative total net GHG emission reductions at time *t*; t CO_2-e

UNC Total project uncertainty, as derived in X-UNC; %

If calculated total project uncertainty (UNC) in module X-UNC is less than or equal to 10%, then no adjustment shall be made for uncertainty.

Step 7. Assessment of Risk

Permanence refers to the longevity of an emissions reduction/removal and the risk of reversal (i.e., the risk that the atmospheric benefit will not be permanent). Wetland projects have the potential for GHG reductions and removals to be reversed when a project has exposure to risk factors, such as tropical storms, fires, increased depth and duration (impounded or permanently flooded) of flooding, damage from wildlife (e.g. nutria *Myocastor coypus*), and erosion; or intentional reversals, such as landowners choosing to discontinue project activities before the project minimum term has ended. Wetland offsets are inherently at some risk of reversal, but this risk can be assessed and mitigated, and the offsets thus made fungible with other offsets and allowances. To manage GHG sequestration, Project Proponents must commit

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to a minimum project term of 40 years, and assess and mitigate reversal risk as described below.

To assess the risk of reversal, the Project Proponents shall conduct a risk assessment addressing both general and project-specific risk factors. General risk factors include, but are not limited to, financial failure, technical failure, management failure, rising land opportunity costs, regulatory and social instability, and natural disturbances. Project-specific risk factors vary by project type. The Project Proponents shall conduct the risk assessment using the tool T-RISK. Only until the release of this tool, the Project Proponents shall use the most updated version of the tool T-PERM.

The output of either tool is an overall risk category for the project, translating into a number of offsets that must be deposited in the ACR buffer pool to mitigate the risk of reversal (unless another ACR approved risk mitigation mechanism is used in lieu of buffer contribution). The Project Proponents shall conduct this risk assessment and propose a corresponding buffer contribution (if applicable). The risk assessment, overall risk category, and proposed buffer contribution shall be included in the GHG Project Plan.

Mitigation of Risk via the ACR Buffer Pool

The Project Proponents shall choose a risk mitigation mechanism. For Project Proponents choosing the ACR buffer pool, the Project Proponents shall contribute either a portion of the project offsets, or an equal number of ERTs of another type and vintage, to a buffer account held by ACR in order to replace unforeseen losses of carbon stocks.

The number of ERTs contributed to the buffer pool shall be determined through the Assessment of Risk given above. Buffer contributions are made with each new issuance of ERTs to a project.

Alternate Risk Mitigation Mechanisms

In lieu of making a buffer contribution of ERTs from either the project or purchased from another acceptable source, Project Proponents may use an alternate ACR-approved risk mitigation mechanism, or propose an insurance product or other risk mitigation mechanism to ACR for approval.

Step 8. Calculation of Emission Reduction Tons (ERTs)

$$ERT_t = (C_{ACR,t2} - C_{ACR,t1}) * (1 - BUF) \quad (3)$$

where:

ERT_t Number of Emission Reduction Tons at time $t = t_2 - t_1$; t CO_2-e

$C_{ACR,t2}$ Cumulative total net GHG emission reductions up to time t_2, adjusted for uncertainty if applicable per equation (2); t CO_2-e

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$C_{ACR,t1}$ Cumulative total net GHG emission reductions up to time t_1 adjusted for uncertainty if applicable per equation (2); t CO_2-e

BUF Fraction of project ERTs contributed to the ACR buffer pool, if applicable; fraction

Per the *Forest Carbon Project Standard, BUF* is determined using an ACR-approved risk assessment tool. If the Project Proponents elects to make the buffer contribution in non-project ERTs, or elects to mitigate the assessed reversal risk using an alternate risk mitigation mechanism approved by ACR, *BUF* shall be set to zero.

PARAMETERS ORIGINATING IN OTHER MODULES

Data /parameter:	$\Delta C_{bsl,WR}$
Data unit:	t CO_2-e
Used in equations:	1
Description:	Cumulative total of the carbon stock changes and greenhouse gas emissions for the baseline scenario.
Module parameter originates in:	BL-WR
Any comment:	

Data /parameter:	$\Delta C_{bsl,WR-WL}$
Data unit:	t CO_2-e
Used in equations:	1
Description:	Cumulative total of the carbon stock changes and greenhouse gas emissions for the baseline scenario including projected wetland loss.
Module parameter originates in:	BL-WR-WL
Any comment:	

Data /parameter:	$\Delta C_{bsl,WR-HM}$
Data unit:	t CO_2-e
Used in equations:	1
Description:	Cumulative total of the carbon stock changes and greenhouse gas emissions for the baseline scenario when the project activity will include hydrologic management.

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Module parameter originates in:	BL-WR-HM
Any comment:	

Data /parameter:	$\Delta C_{bsl,WR\text{-}HM\text{-}WL}$
Data unit:	t CO_2-e
Used in equations:	1
Description:	Cumulative total of the carbon stock changes and greenhouse gas emissions for the baseline scenario including projected wetland loss when the project activity will include hydrologic management.
Module parameter originates in:	BL-WR-HM-WL
Any comment:	

Data /parameter:	ΔC_{ACTUAL}
Data unit:	t CO_2-e
Used in equations:	1
Description:	Cumulative total of carbon stock changes and greenhouse gas emissions for the project scenario.
Module parameter originates in:	PS-WR
Any comment:	

Data /parameter:	$\Delta C_{ACTUAL\text{-}HM}$
Data unit:	t CO_2-e
Used in equations:	1
Description:	Cumulative total of carbon stock changes and greenhouse gas emissions for the project scenario when the project activity includes hydrologic management.
Module parameter originates in:	PS-WR-HM
Any comment:	

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American Carbon Registry
AT WINROCK INTERNATIONAL

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

RESTORATION OF POCOSIN WETLANDS

VERSION 1.0

October 2017

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October 2017

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ACKNOWLEDGEMENTS

The development of this methodology was a collective effort led by TerraCarbon and The Nature Conservancy (TNC), with the drafting team led by David Shoch, James Eaton and Erin Swails of TerraCarbon. Funding was provided by Duke Energy LLC and administered by TNC. In particular, the drafting team wishes to acknowledge, for their input and careful review of previous drafts, the contributions of Chuck Peoples, Christine Pickens, Brian Boutin and Eric Soderholm of TNC, Sara Ward and Howard Phillips of USFWS, Ken Krauss and Nicole Cormier of the U.S. Geological Survey, Linda Blum of the University of Virginia and Philippe Hensel of the National Oceanographic and Atmospheric Administration. Development of the conceptual framework and monitoring approaches benefited from research findings at Pocosin Lakes National Wildlife Refuge generously shared by Curt Richardson and Hongjun Wang of Duke University Wetland Center and Louise Armstrong of East Carolina University.

This methodology was developed by The Nature Conservancy and TerraCarbon.

The Nature Conservancy

Terra Carbon

ACRONYMS

ACR	American Carbon Registry
C	Carbon
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CH_4	Methane
ERT	Emission Reduction Ton
IPCC	Intergovernmental Panel on Climate Change
GHG	Greenhouse gas
GIS	Geographic information system
GPS	Global positioning system
GWP	Global warming potential
N_2O	Nitrous oxide
MT	Metric ton
QA	Quality assurance
QC	Quality control
RMSE	Root mean squared error
RSET	Rod Surface Elevation Tables
RTK	Real Time Kinematic

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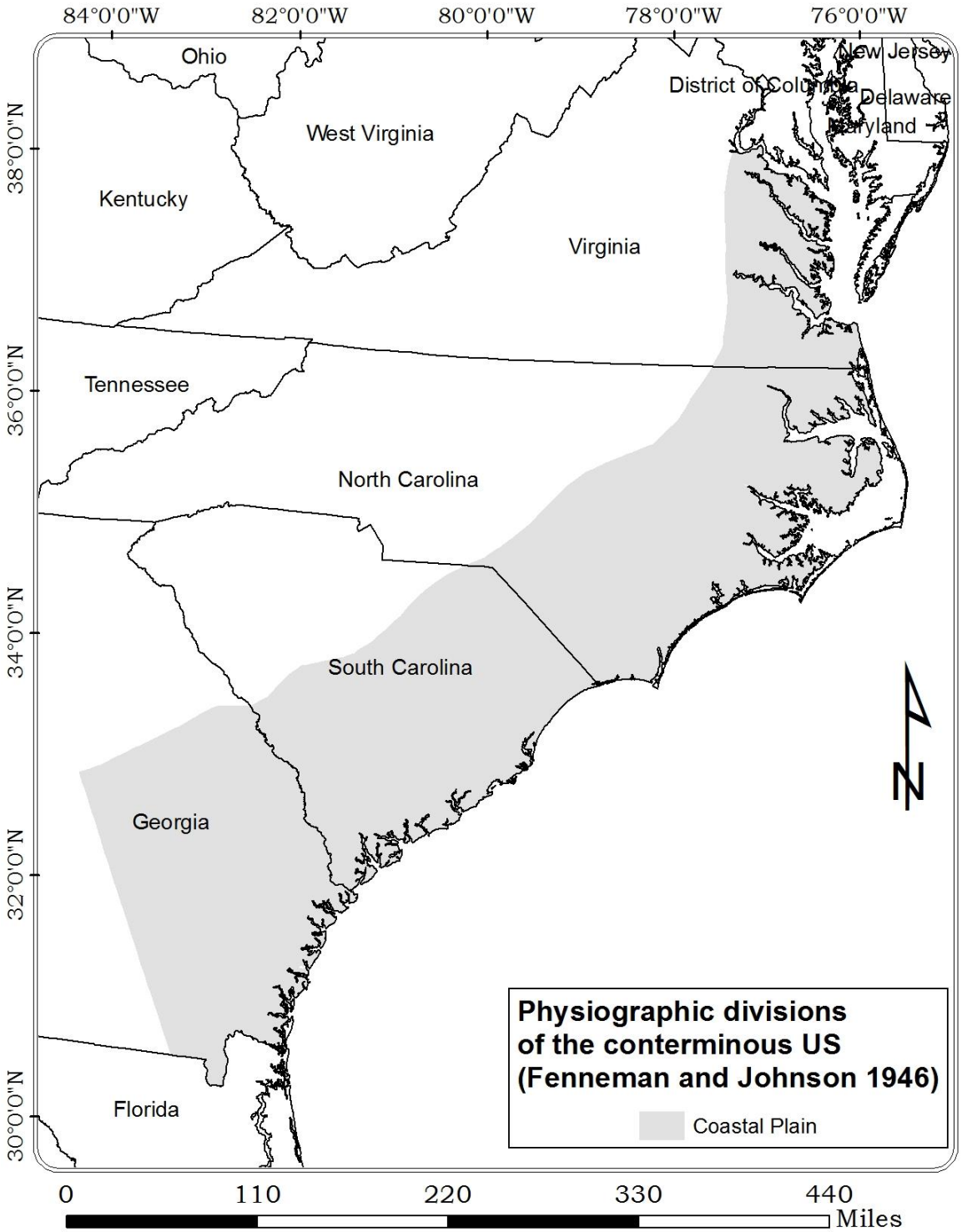
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1 METHODOLOGY DESCRIPTION

1.1 SCOPE

This methodology accounts for the GHG emission reductions from rewetting previously drained pocosins. Pocosins are here defined as freshwater wetlands, with some component of broad-leaved evergreen shrubs or low trees, on organic soils in the coastal plain of southeast Virginia, North Carolina, South Carolina or Georgia, that are seasonally saturated primarily through precipitation. The baseline scenario assumes continuation of the pre-existing drained state, and ongoing emissions from the soil organic carbon (peat) pool associated with drainage. Leakage is excluded from accounting via an applicability condition stipulating the absence of any productive land use (that could be displaced or result in commodity shortages) in the project area within five years prior to the project start date.

Figure 1: Area of Applicability (Shaded) of the Methodology – Coastal Plain of Virginia, North Carolina, South Carolina and Georgia



1.2 APPLICABILITY CONDITIONS

General applicability conditions for this methodology are:

I. The project area has been free of any land use that could be displaced outside the project area (e.g. agriculture) for five or more years prior to project start date;
II. The project area is a previously-drained pocosin. Continuation of the drained state is the most likely baseline scenario. Throughout this document, “drained” is defined as subject to a lowering of water table due to deliberate hydrological manipulation, e.g. through ditching and diking;
III. Project activity involves re-wetting previously drained wetlands, in which rewetting is defined as raising the elevation of the average annual water table in drained wetland by partially or entirely reversing the pre-existing drained state;
IV. Any areas of soil disturbance associated with implementation of the project activity are less than 3% of the project area;
V. N-fertilizers are not used in the with-project scenario;
VI. Infrastructure and/or management protocols are in place to manage for average annual water level at or below the surface elevation mid-point of the project area (e.g. by setting maximum height of outflow structure equal to the surface elevation mid-point of the project area);
VII. The project activity does not result in increased GHG emissions outside the project area via hydrological connectivity (i.e. would not result in drainage of adjacent areas);
VIII. No timber harvest will occur in the baseline or with-project scenarios;
IX. The project activity and project area meet all eligibility requirements set by the currently governing versions of the American Carbon Registry Standard and American Carbon Registry Forest Carbon Project Standard.
X. A baseline site must be identified and accessible on which one or more parameters are monitored in the baseline scenario. Parameter-specific criteria to demonstrate the appropriateness of a baseline site are detailed in Table 4.

Use of this methodology also requires that applicability conditions specific to the chosen accounting approach (stock change or flux; see Section 1.4) are met, as well as similarity criteria demonstrating the validity of one or more selected baseline sites (see Section 1.4 below).

1.3 POOLS AND SOURCES

1.3.1 Carbon Pools

Table 1: Carbon Pools Accounted for in the Project Boundary

CARBON POOLS	INCLUDED / OPTIONAL / EXCLUDED	JUSTIFICATION / EXPLANATION OF CHOICE
Above-ground biomass carbon	Included (includes trees and woody shrubs)	Required as the project activity may result in increased mortality or decreased growth and recruitment
Below-ground biomass carbon	Included (includes trees and woody shrubs)	Required as the project activity may result in increased mortality or decreased growth and recruitment
Dead wood	Excluded	Conservatively excluded (pool is expected to be greater in the project scenario with potentially higher mortality and lower de-composition due to flooding)
Harvested wood products	Excluded	Excluded per applicability condition
Litter / Forest Floor	Excluded	The pool is conservatively omitted
Soil organic carbon	Included	Largest pool expected to be subject to change with the project activity

1.3.2 Emission Sources

Emissions of CO_2 are included through monitoring the carbon pools above.

Emissions of N_2O and CH_4 from intentional burns in the project scenario are included.

Emissions of N_2O and CH_4 from heterotrophic respiration are excluded as insignificant[1] within the constraints of the methodology.

1.4 METHODOLOGY SUMMARY

The methodology centers on two different approaches for estimating belowground emissions: (1) a stock change approach which estimates emissions from net surface level change (due to subsidence and root dynamics), and (2) a flux approach which models emissions as a function of one or more proxy variables (e.g., soil moisture, temperature, etc.) that are demonstrated to be significantly correlated with belowground emissions. One or the other approach may be used, provided approach-specific applicability conditions are met.

The methodology is simplified by exclusion of leakage from accounting (explained above) and by accounting for uncertainty as a step in the derivation of parameter values (i.e. uncertainty is not accounted separately and deducted in final calculations as in other methodologies). Uncertainty is accounted in this way for all parameters driving differences between with-project and baseline scenario emissions, which include surface elevation change, above- and belowground biomass, proxy (independent) variables and emissions (dependent variable) modeled as a function of proxy variable(s). Also, in all accounting steps throughout this methodology, sources/sinks collectively amounting to less than 3% of total ex-ante estimate of net emission reductions may be excluded from accounting.

Monitoring is conducted in the project area and in a valid baseline site that matches conditions expected in the project area in the absence of the project activity (i.e. rewetting) (see Table 4). Either net surface elevation change (stock change approach) or one or more proxy variables (flux approach) are monitored to estimate emissions from belowground. Trees and woody shrubs are monitored on permanent sample plots to assess and account for any detected differences in stock change due to growth/recruitment/mortality between the project area and the baseline site. With the stock change approach, peat accretion is monitored as an undifferentiated component of net surface elevation change. Peat accretion is not monitored with the flux approach.

Unintentional (natural) fire is conservatively excluded from accounting. Where unintentional burns occur in the project area, it is assumed that equal emissions occur in the baseline (i.e. net zero). Intentional fires (e.g., prescribed burns) in the project area are monitored and emissions (from CO_2, N_2O and CH_4) accounted.

[1] Richardson et al. 2014. Impacts of Peatland Ditching and Draining on Water Quality and Carbon Sequestration Benefits of Peatland Restoration. Final Report. Duke University Wetlands Center for the US Fish and Wildlife Service and The Nature Conservancy.

As explained above, two approaches are provided for estimating net greenhouse gas emissions in the baseline and with-project cases: stock change and flux. One approach must be selected and used for the entire project crediting period.

The stock change approach may be employed if the following applicability conditions are met and measurement procedures adhered to (note that conditions related to measurement and monitoring apply equally to the project and baseline cases, as measurement and monitoring are carried out in the project area and in a representative baseline site):

XI. Net surface elevation change measured using Rod Surface Elevation Tables (RSETs), Real Time Kinematic (RTKs) satellite-based approaches and/or other technologies;

XII. Clear and detailed rules and procedures for determining peat surface level, and distinguishing it from any overlying litter, are documented in field standard operating procedures and adhered to;

XIII. Bulk density in top 10 cm (below any overlying litter layer) is monitored; the top layer being the aerated labile portion from which emissions are expected to be sourced, and as well is a conservative value as it's the lowest bulk density throughout the peat profile. The top 10 cm should also capture the majority of root biomass, and permit estimation of emissions from surface level change resulting from root expansion/mortality. Bulk density samples must include soil organic carbon and belowground biomass (fine and coarse roots).

XIV. Baseline site has been subject to drainage/hydrological alteration for at least 10 years (to minimize influence of new root growth and expansion on surface elevation and bulk density)

XV. Repeat measurements of surface elevation change are made at the same water table level (+/- 10% of level at the time of the t = 0 measurement, as recorded at the same site(s) measured at t =0) and in the dry season. Water table level will be assessed from data from a groundwater well located at the site, or if this does not exist, from the nearest USGS groundwater well, sourced from https://waterdata.usgs.gov/nwis/gw ;

XVI. In with-project case, initial surface elevation level is measured no less than 12 months after re-wetting takes place (after initial swell has occurred);

XVII. In both the project area and baseline site, no significant erosion or sedimentation expected to occur (flat terrain, no river flow over project area);

XVIII. In both the project area and baseline site, no significant compaction (by machinery or treading) expected to occur and procedures will be in place to safeguard against compaction resulting from surface elevation measurements in the field.

Note that the stock change approach treats soil organic carbon and belowground (root) biomass as a single source/sink.

The flux approach may be employed where a regression equation correlating one or more proxy variables to belowground emissions meeting the following conditions is available:

XIX. Peer-reviewed;

XX. Empirically-based;

XXI. Dependent variable is restricted to heterotrophic emissions (due to microbial respiration) from the soil organic carbon and dead belowground biomass pools (i.e. heterotrophic respiration of litter and autotrophic respiration are excluded);

XXII. Relationship between proxy variable and emissions must be significant at $P < 0.1$ and unbiased (i.e. with minimal trend in residuals);

XXIII. The study site(s) from which proxy relationship developed must include drained pocosins (as defined in Section 1.1) that have been subject to drainage/hydrological alteration for no less than 50% of the length of time that the project area has been subject to drainage/ hydrological alteration prior to project start;

XXIV. Relationship incorporates one or more proxy variables that are:

A. measured ex post in a valid baseline site,

B. measured ex post in the project area (e.g., precipitation, temperature), and/or

C. modeled in the project area on the basis of proxy variables monitored ex post in the project area (e.g., water table modeled from monitored precipitation);

XXV. Uncertainty in predicted emissions (dependent variable) is known and calculated as the root mean squared error (RMSE);

XXVI. Relationship must be based on emissions assessed over at least one entire year, with frequent (at least bi-monthly) measurements.

The same relationship must be used in both the project and baseline cases. The regression may be revised based on new data, provided it meets the above requirements. See also Section 5 for further guidance.

Accounting using each approach is summarized in the following diagrams, which demonstrate key parameters and calculation flow. The diagrams are intended only to provide a high level view of the methodology structure. Operation of the methodology follows measurement and calculation procedures detailed in Sections 3, 4 and 5 below.

Figure 2: Overview of Accounting Using the Stock Change Approach

Note that change in aboveground biomass carbon stocks in the baseline is accounted in $\mathrm{Net}\Delta\mathrm{AGB}_{\mathrm{wp}}$ which represents the net of baseline and with project changes in this pool, hence "net change". GHG emissions resulting from intentional burns in the project scenario are also included in accounting (not included in the figure for ease of readability).

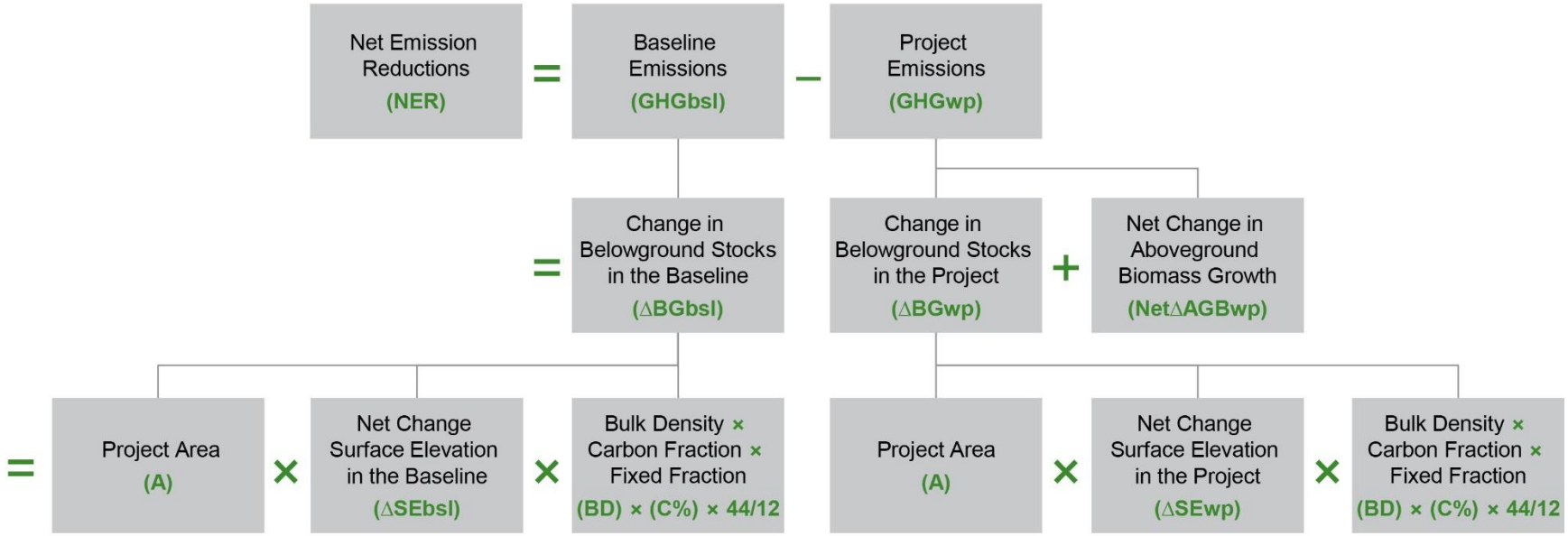
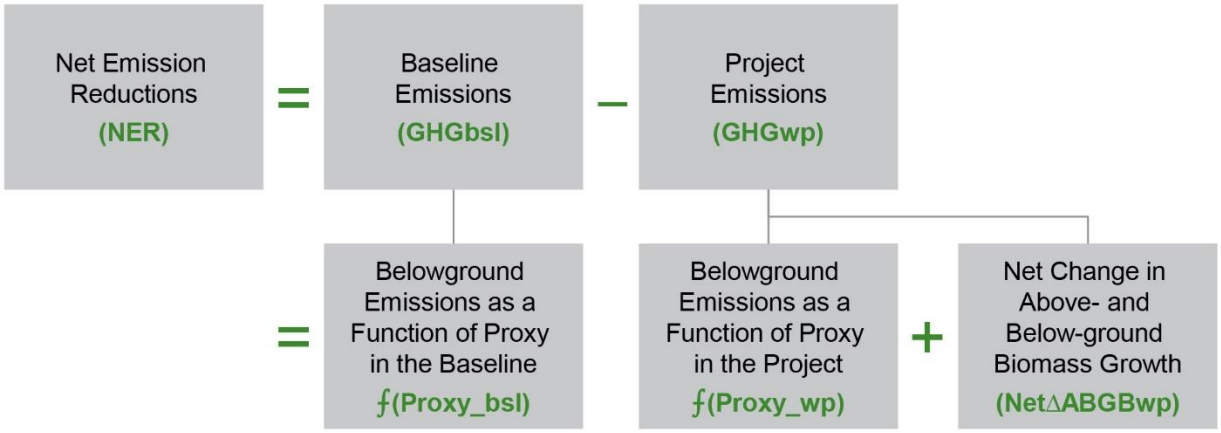


Figure 3: Overview of Accounting Using the Flux Approach.

Note that change in above- and belowground biomass carbon stocks in the baseline is accounted in $\mathrm{Net}\Delta\mathrm{ABGB}_{\mathrm{wp}}$ which represents the net of baseline and with project changes in this pool, hence "net change". GHG emissions resulting from intentional burns in the project scenario are also included in accounting (not included in the figure for ease of readability).



Monitoring procedures are reviewed in the tables below, which, as for the diagrams above, are intended as an overview and to draw distinctions in requirements between the two accounting approaches. Note that for both the stock change and flux approaches, a baseline site is required to monitor parameters in the baseline scenario.

Table 2: Monitoring for the Stock Change Approach

PARAMETER	GENERAL MONITORING OF BASELINE SCENARIO	GENERAL MONITORING OF PROJECT SCENARIO
Net surface elevation change; $\Delta\mathrm{SE}$	Monitored on baseline site via direct measurement of permanent sample points	Monitored on project area via direct measurement of permanent sample points
Aboveground biomass carbon; AGB	Monitored on baseline site via direct measurement on permanent sample plots	Monitored on project area via direct measurement on permanent sample plots
Area of unintentional fire; $\mathrm{A}_{\mathrm{burn_unint}}$	Monitored in project area via aerial imagery and management records	Monitored in project area via aerial imagery and management records

PARAMETER	GENERAL MONITORING OF BASELINE SCENARIO	GENERAL MONITORING OF PROJECT SCENARIO
Area of intentional fire; A_{burn_int}	N/A	Monitored in project area via aerial imagery and management records

Table 3: Monitoring for the Flux Approach

PARAMETER	GENERAL MONITORING OF BASELINE SCENARIO	GENERAL MONITORING OF PROJECT SCENARIO
Proxy variable(s) significantly correlated with belowground emissions; Proxy A, B, etc …	Either monitored via direct measurement in a valid baseline site, monitored via direct measurement in the project area, or modeled in the project area (e.g. using a hydrologic model) on the basis of one or more monitored, directly-measured proxy variables (e.g. precipitation) in the project area.	Monitored via direct measurement in the project area
Above- and belowground biomass carbon; $ABGB$	Monitored on baseline site via direct measurement on permanent sample plots	Monitored on project area via direct measurement on permanent sample plots
Area of intentional fire; A_{burn_int}	N/A	Monitored in project area via aerial imagery and management records
Surface elevation change due to intentional fire; $\Delta SE_{burn_int,wp,t}$	N/A	Monitored in the project area in the planned burn area via direct measurement of sample points immediately prior to and after the burn
Area of unintentional fire; A_{burn_unint}	Monitored in project area via aerial imagery and management records	Monitored in project area via aerial imagery and management records

PARAMETER	GENERAL MONITORING OF BASELINE SCENARIO	GENERAL MONITORING OF PROJECT SCENARIO
Surface elevation change due to unintentional fire; $\Delta SE_{burn_unint,wp,t}$	Monitored in the project area via direct measurement of sample points in the burn area and outside the burn area after the burn	Monitored in the project area via direct measurement of sample points in the burn area and outside the burn area after the burn

1.4.1 Baseline Site Similarity Criteria

Operation of this methodology requires that one or more baseline sites be identified on which to monitor a range of parameters in the baseline scenario. The table below outlines similarity criteria that must be met to demonstrate the validity of a baseline site.

Table 4: Baseline Site Similarity Criteria

BASELINE SITE SIMILARITY CRITERION	NET SURFACE ELEVATION CHANGE; ΔSE	ABOVEGROUND BIOMASS CARBON; AGB AND ABOVE- AND BELOWGROUND BIOMASS CARBON; $ABGB$	PROXY VARIABLE(S) SIGNIFICANTLY CORRELATED WITH BELOWGROUND EMISSIONS; PROXY A, B, ETC …
Drained freshwater wetland on organic soils in the coastal plain of southeast Virginia, North Carolina, South Carolina or Georgia	Yes	Yes	Yes
Flat terrain (slopes not exceeding 10%), not located within any immediate river floodplain, and unlikely to be subject to significant ongoing soil compaction (by machinery or treading) and/or mechanical disturbance (e.g. tilled farmland subject to repeated traffic by heavy machinery).	Yes	N/A	N/A
Not subject to fire	Yes	Yes	N/A

BASELINE SITE SIMILARITY CRITERION	NET SURFACE ELEVATION CHANGE; ΔSE	ABOVEGROUND BIOMASS CARBON; AGB AND ABOVE- AND BELOWGROUND BIOMASS CARBON; $ABGB$	PROXY VARIABLE(S) SIGNIFICANTLY CORRELATED WITH BELOWGROUND EMISSIONS; PROXY A, B, ETC …
Mean bulk density of top 10 cm of peat at project start date*	Within +/- 20% of mean bulk density in project area	N/A	N/A
Mean percent carbon (as % of dry weight) of top 10 cm of peat at project start date*	Within +/- 20%, in relative terms, of mean percent organic matter in project area	N/A	N/A
Mean peat depth at project start date*	Equal to or less than mean peat depth in project area	N/A	N/A
Average annual water level at project start date**	Within +/-20% of average annual water level in project area prior to project start (i.e. prior to rewetting of project area)	Within +/-20% of average annual water level in project area prior to project start (i.e. prior to rewetting of project area)	N/A

* For these criteria, estimates must be derived from un-biased, representative sampling of the reference site, with a minimum sample size of 20, and accuracy ensured through adherence to the same measurement procedures for corresponding parameters measured and monitored in the project area (Section 5).

** Average annual water table (for the year preceding the project start date) must be estimated from data from a groundwater well located at the site, or if this does not exist, from the nearest USGS groundwater well, sourced from https://waterdata.usgs.gov/nwis/gw.

BASELINE SITE SIMILARITY CRITERION	NET SURFACE ELEVATION CHANGE; ΔSE	ABOVEGROUND BIOMASS CARBON; AGB AND ABOVE- AND BELOWGROUND BIOMASS CARBON; $ABGB$	PROXY VARIABLE(S) SIGNIFICANTLY CORRELATED WITH BELOWGROUND EMISSIONS; PROXY A, B, ETC …
Length of time subject to drainage/hydrological alteration prior to project start[2]	No less than 50% of length of time the project area has been subject to drainage/ hydrological alteration prior to project start	N/A	N/A
Vegetation: Age class and percent cover trees and shrubs	Similar to project area immediately prior to project start (age class within 10 years, percent cover trees and shrubs, and basal area of pines > 10 cm dbh within +/- 20%)	Similar to project area immediately prior to project start (age class within 10 years, percent cover trees and shrubs, and basal area of pines > 10 cm dbh within +/- 20%)	N/A
Value of proxy variable at project start date	N/A	N/A	Not outside of range of measured values from which regression derived

[2] Note that both the project area and baseline site must have been subject to drainage/hydrological alteration for at least 10 years per applicability condition for the stock change approach

Baseline sites should ideally be selected to have stable management through the project crediting period, however, should the baseline site become invalid (due to non-compliance with similarity criteria, e.g. if it becomes subject to a burn) at any time during the project crediting period, a new valid baseline site may be selected to replace the former, or the existing baseline site may be reconfigured (e.g., excluding a burned area, and any sample points within it, from the reference site), while continuing to ensure compliance with the similarity criteria. Different baseline sites may be used for different parameters. Multiple baseline sites may be used for a single parameter, in which case the similarity criteria are assessed for the composite area.

2 BOUNDARIES, ADDITIONALITY AND PERMANENCE

2.1 PROJECT GEOGRAPHIC BOUNDARY

The project boundary shall be defined at the beginning of a proposed project activity and shall remain fixed through the project crediting period. The project activity may contain more than one discrete area of land.

For all discrete land areas included in the project boundary, the following will be provided:

- Unique identifier for each discrete parcel of land;
- Geo-referenced GIS shapefile of the land parcel boundary;
- Details of ownership and land use rights holder.

Further guidance is provided in the project area parameter table in Section 5.

2.2 PROJECT TEMPORAL BOUNDARY

The project crediting period is the time period for which GHG emission reductions generated by the project are accounted and eligible for issuance as Emission Reduction Tons (ERTs). The project must have a robust monitoring plan covering this period.

The start of the crediting period is marked by the start of the project activity, i.e. following the on-set of rewetting. Note that using the stock change approach the start of the crediting period must be no less than 12 months following the onset of rewetting. The crediting period shall be for 20 years, and may be renewed following governing ACR requirements.

2.3 ADDITIONALITY

The project activity must demonstrate additionality applying the ACR's three-pronged additionality test: beyond regulatory requirements, beyond common practice, and facing at least one of three implementation barriers (financial, technological, or institutional).

2.4 METHOD OF ASSURANCE OF PERMANENCE

To ensure permanence of credited emission reductions, the project will apply the ACR Tool for AFOLU Non-Permanence Risk Analysis and Buffer Determination.

3 STOCK CHANGE APPROACH: BASELINE AND WITH-PROJECT SCENARIOS

3.1 BASELINE ACCOUNTING

Equation 1

$$\mathbf{GHG_{bsl,t}} = \mathbf{\Delta BG_{stock_bsl,t}}$$

WHERE

$\mathbf{GHG_{bsl,t}}$	Annual greenhouse gas emissions in the baseline in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$\mathbf{\Delta BG_{stock_bsl,t}}$	Mean annual change in the soil organic carbon and belowground biomass using the stock change method in the baseline scenario in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
t	1, 2, 3, … **t** years elapsed since the project start date

Note that change in aboveground biomass carbon stocks in the baseline is accounted in parameter ΔAGB_{wp} (derived in Section 3.2.2 below) which represents the net of baseline and with project changes in aboveground biomass carbon stocks.

3.1.1 Emissions from Belowground in the Baseline

Emissions from belowground are estimated from net surface level change. Note that the emission inferred from net surface level change, ΔBG_{stock_bsl}, covers net emissions (due to sequestration and respiration) from soil organic carbon and belowground biomass.

Equation 2

$$\mathbf{\Delta BG_{stock_bsl,t}} = \left(\mathbf{A} - \mathbf{A_{burn_unint,wp,t}}\right) \times -\mathbf{\Delta SE_{bsl,t}} \times \left(\frac{\mathbf{1}}{\mathbf{x}}\right) \times \mathbf{10} \times \mathbf{BD_{wp,t-x}} \times \mathbf{C\%_{soil,wp}} \times \left(\frac{\mathbf{44}}{\mathbf{12}}\right)$$

WHERE

$\Delta BG_{stock_bsl,t}$	Mean annual change in the soil organic carbon and belowground biomass pools using the stock change method in the baseline scenario in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$\Delta SE_{bsl,t}$	Mean net surface elevation change (subsidence + peat accretion + root expansion/mortality) in the baseline site in monitoring interval ending in year **t**; mm
$BD_{wp,t-x}$	Mean dry bulk density in the project area at time **t-x**; g cm^{-3}
$C\%_{soil,wp}$	Percentage of soil organic **C** (percent dry weight) in the project area; %
$44/12$	Ratio of molecular weight of CO_2 to carbon, MT CO_2-e MT C^{-1}
A	Project area; ha
$A_{burn_unint,wp,t}$	Area of unintentional burn in the project area occurring in monitoring interval ending in year **t**; ha
t	1, 2, 3, … **t** years elapsed since the project start date
x	Number of years in monitoring interval; years

The net surface elevation change term is monitored in the baseline site. Parameter $\Delta SE_{bsl,t}$ incorporates uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value (see parameter table).

3.2 WITH-PROJECT ACCOUNTING

Equation 3

$$GHG_{wp,t} = \Delta BG_{stock_wp,t} + Net\Delta AGB_{wp,t} + E_{BGburn_int,wp,t} + E_{AGBburn_int,wp,t}$$

WHERE

$GHG_{wp,t}$	Annual greenhouse gas emissions in the project scenario in monitoring interval ending in year **t**; MT CO_2e yr^{-1}

$\Delta BG_{stock_wp,t}$	Mean annual change in the soil organic carbon and belowground biomass pool using the stock change method in the project scenario in monitoring interval ending in year t; MT CO_2e yr^{-1}
$Net\Delta AGB_{wp,t}$	Annual net change in aboveground biomass carbon stocks in the project scenario in monitoring interval ending in year t; MT CO_2e yr^{-1}
$E_{BGburn_int,wp,t}$	Emissions from soil organic carbon from intentional fire in the project scenario in year t; MT CO_2-e
$E_{AGBburn_int,wp,t}$	Emissions from aboveground biomass from intentional fire in the project scenario in year t; MT CO_2-e
t	1, 2, 3, … t years elapsed since the project start date

3.2.1 Emissions from Belowground in the Project

Emissions from belowground are estimated from net surface level change. Note that the emission inferred from net surface level change, ΔBG_{stock_bsl}, covers net emissions (due to sequestration and respiration) from soil organic carbon and belowground biomass.

Equation 4

$$\Delta BG_{stock_wp,t} = (A - A_{burn_unint,wp,t}) \times -\Delta SE_{wp,t} \times \left(\frac{1}{x}\right) \times 10 \times BD_{wp,t-x} \times C\%_{soil,wp} \times \left(\frac{44}{12}\right)$$

WHERE

$\Delta BG_{stock_wp,t}$	Mean annual change in the soil organic carbon and belowground biomass pool using the stock change method in the project scenario in monitoring interval ending in year t; MT CO_2e yr^{-1}
$\Delta SE_{wp,t}$	Mean net surface elevation change (subsidence + peat accretion + root expansion/mortality) in the project area in monitoring interval ending in year t; mm
$BD_{wp,t-x}$	Mean dry bulk density in the project area at time t-x; g cm^{-3}
$C\%_{soil,wp}$	Percentage of soil organic C in the project area; %
44/12	Ratio of molecular weight of CO_2 to carbon, MT CO_2-e MT C^{-1}

A	Project area; ha
$A_{burn_unint,wp,t}$	Area of unintentional burn in the project area occurring in monitoring interval ending in year t; ha
t	1, 2, 3, … t years elapsed since the project start date
x	Number of years in monitoring interval; years

The net surface elevation change term must be monitored in the project area. Parameter $\Delta SE_{wp,t}$ incorporates uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value (see parameter table).

Bulk density is measured at the project start and every 5 years and includes belowground biomass (roots) and soil organic carbon.

3.2.2 Emissions from Aboveground Biomass in the Project

Emissions from aboveground biomass (in trees and shrubs) in the project, $Net\Delta AGB_{wp}$, represent net emissions from aboveground biomass (i.e. net of baseline and with project) resulting from stock change in the project case relative to a baseline site. This term is set equal to zero if there is no significant difference (significantly different using an unpaired t test at P <0.05) in stock change between the project and the baseline site.

3.2.2.1 STEP 1

Measure change in stocks of aboveground biomass in the project area and in a baseline site. Stock change in aboveground biomass is measured on permanent sample plots, and represents the net of biomass increment, recruitment and mortality. Calculate mean annual change in stocks of aboveground biomass in the project area, ΔAGB_{wp}, and in a baseline site, ΔAGB_{bsl}.

Equation 5

$$\Delta AGB_{wp,t} = \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} \left((AGB_{wp,j,t} - AGB_{wp,j,t-x}) \times \left(\frac{1}{x}\right) \right)$$

WHERE

$\Delta AGB_{wp,t}$	Mean annual change in aboveground biomass carbon stocks in the project area in monitoring interval ending in year **t**; MT CO_2e ha^{-1} yr^{-1}
$AGB_{wp,j,t}$	Aboveground biomass carbon stocks in the project area in plot **j** at time **t**; MT CO_2e/ha
$AGB_{wp,j,t-x}$	Aboveground biomass carbon stocks in the project area in plot **j** at time **t-x**; MT CO_2e/ha
j	1, 2, 3 … **n** sample plots
x	Number of years in monitoring interval; years
t	1, 2, 3, … **t** years elapsed since the project start date

Equation 6

$$\Delta AGB_{bsl,t} = \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} \left((AGB_{bsl,j,t} - AGB_{bsl,j,t-x}) \times \left(\frac{1}{x}\right) \right)$$

WHERE

$\Delta AGB_{bsl,t}$	Mean annual change in aboveground biomass carbon stocks in the baseline reference area in monitoring interval ending in year **t**; MT CO_2e ha^{-1} yr^{-1}
$AGB_{bsl,j,t}$	Aboveground biomass carbon stocks in the baseline reference area in plot **j** at time **t**; MT CO_2e/ha
$AGB_{bsl,j,t-x}$	Aboveground biomass carbon stocks in the baseline reference area in plot **j** at time **t-x**; MT CO_2e/ha
j	1, 2, 3 … **n** sample plots
x	Number of years in monitoring interval; years
t	1, 2, 3, … **t** years elapsed since the project start date

3.2.2.2 STEP 2

If $\Delta AGB_{wp,t}$ is not equal to $\Delta AGB_{bsl,t}$ (significantly different using an unpaired t test at P <0.05), then net emissions from aboveground biomass carbon are equal to the difference in stock

change between the baseline site and the project area. Note that this term can be less than zero, where growth in the project area exceeds that in the baseline site, e.g., due to tree and shrub planting efforts conducted as part of the project activity.

Equation 7

$$\mathbf{Net\Delta AGB_{wp,t} = \left((\Delta AGB_{bsl,t} + UNC_{\Delta AGB,bsl,t}\right) - \left(\Delta AGB_{wp,t} - UNC_{\Delta AGB,wp,t}\right)\right) \times \left(A - A_{burn_unint,wp,t}\right)}$$

WHERE

$Net\Delta AGB_{wp,t}$	Annual net change in aboveground biomass carbon stocks in the project area in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$\Delta AGB_{wp,t}$	Mean annual change in aboveground biomass carbon stocks in the project area in monitoring interval ending in year **t**; MT CO_2e ha^{-1} yr^{-1}
$\Delta AGB_{bsl,t}$	Mean annual change in aboveground biomass carbon stocks in the baseline reference area in monitoring interval ending in year **t**; MT CO_2e ha^{-1} yr^{-1}
$UNC_{\Delta AGB,wp,t}$	Half width of 90% confidence interval exceeding 10% of the mean annual change in aboveground biomass carbon stocks in the project area in monitoring interval ending in year **t**; MT CO_2e ha^{-1} yr^{-1}
$UNC_{\Delta AGB,bsl,t}$	Half width of 90% confidence interval exceeding 10% of the mean annual change in aboveground biomass carbon stocks in the baseline reference area in monitoring interval ending in year **t**; MT CO_2e ha^{-1} yr^{-1}
A	Project area; ha
$A_{burn_unint,wp,t}$	Area of unintentional burn in the project area occurring in monitoring interval ending in year **t**; ha
t	**t** years elapsed since the project start date

If $\Delta AGB_{wp,t}$ is not significantly different from $\Delta AGB_{bsl,t}$, then

$Net\Delta AGB_{wp,t} = 0$

3.2.3 Emissions from Fire in the Project

3.2.3.1 UNINTENTIONAL BURNS

Where unintentional burns occur in the project area, emissions from those burns are assumed, conservatively, to be equal in the project and baseline scenarios. Emissions from unintentional burns in the project area are excluded from accounting by delineating the area of the burn, parameter $A_{burn_unint,wp,t}$, consulting aerial imagery and assigning zero net emissions to the area for the monitoring interval spanning the burn (i.e. from the monitoring event immediately prior to the burn to the monitoring event immediately after the burn); see equations 2 and 4 above. Plans for intentional burns (e.g. prescribed burns) in the project area must be recorded in management records to distinguish unintentional burns (on the absence of management records). Any sample plots/points for surface elevation and/or aboveground biomass located within the area of an unintentional burn in the project area, will not be used to calculate net change in surface elevation, $\Delta SE_{wp,t}$, or change in aboveground biomass stocks, $\Delta AGB_{wp,t}$, in the project area for the monitoring interval spanning the burn (i.e. from the monitoring event immediately prior to the burn to the monitoring event immediately after the burn).

3.2.3.2 INTENTIONAL BURNS

Carbon dioxide emissions from the belowground and aboveground biomass pools resulting from intentional burns in the project are captured through monitoring parameters $\Delta SE_{wp,t}$ and $\Delta AGB_{wp,t}$. referencing measurements collected at all sample plots/points for surface elevation and/or aboveground biomass located within the project area.

Nitrous oxide and methane emissions from intentional burns from belowground (due to combustion of peat), $E_{BGburn_int,wp,t}$, and aboveground biomass, $E_{AGBburn_int,wp,t}$, are monitored referencing pre- and post-burn measurements collected at the subset of sample plots/points for surface elevation and aboveground biomass located within the actual intentional burned area in year *t*. The actual intentional burned area, $A_{burn_int,wp,t}$, is determined after the burn takes place by consulting aerial imagery.

Parameters $\Delta SE_{wp,t}$ and $\Delta AGB_{Aburn_int_wp,t}$ incorporate uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value (see parameter tables). Note that because this involves subsets of the total sampling networks, it may be desired to augment sampling in the intentional burn area prior to the burn to reduce uncertainty.

Equation 8

$$\mathbf{E_{BGburn_int,wp,t}} = \sum_{\mathbf{g=1}}^{\mathbf{G}} (\mathbf{A_{burn_int,wp,t}} \times -\mathbf{\Delta SE_{wp,b,t}} \times \mathbf{10} \times \mathbf{BD_{stock,wp,t-x}}) \times \mathbf{EF_{peat,g}} \times \mathbf{GWP_g}$$

WHERE

$E_{BGburn_int,wp,t}$	Emissions from soil organic carbon from intentional fire in the project scenario in year **t**; MT CO_2-e
$\Delta SE_{wp,b,t}$	Mean net surface elevation change in the actual area of intentional burn in the project area in year **t**; mm
$BD_{stock,wp,t-x}$	Mean dry bulk density (as defined for the stock change approach; i.e. including coarse roots) in the project area at time **t-x**; g cm^{-3}
$EF_{peat,g}$	Emission factor for gas **g**; MT gas **g** emitted × MT dry matter peat burned^{-1}
GWP_g	Global warming potential for gas **g**; MT CO_2e/t gas **g**
$A_{burn_int,wp,t}$	Actual (not planned) area of intentional burn in the project area in year **t**; ha
t	1, 2, 3, … **t** years elapsed since the project start date
10	Converts result to units of metric tons
g	1, 2, 3 … G greenhouse gases (to include nitrous oxide and methane)
x	Number of years in monitoring interval; years

Equation 9

$$E_{AGBburn_int,wp,t} = \sum_{g=1}^{G} (A_{burn_int,wp,t} \times -\Delta AGB_{Aburn_int,wp,t} \times 0.58) \times EF_{biomass,g} \times GWP_g$$

WHERE

$E_{AGBburn_int,wp,t}$	Emissions from aboveground biomass from intentional fire in the project scenario in year **t**; MT CO_2-e
$\Delta AGB_{Aburn_int,wp,t}$	Mean change in aboveground biomass carbon stocks in the actual (not planned) area of intentional burn in the project area in year **t**; MT CO_2e ha^{-1} yr^{-1}
0.58	Factor to convert MT CO_2e to MT dry matter biomass (assumes 0.47 MT C MT d.m.$^{-1}$ and 44/12 ratio of molecular weight of CO_2 to carbon, MT CO_2-e MT C^{-1})
$EF_{biomass,g}$	Emission factor for gas **g**; MT CO_2e emitted × MT dry matter biomass burned^{-1}

GWP_g	Global warming potential for gas **g**; MT CO_2e MT gas g $^{-1}$
$A_{burn_int,wp,t}$	Actual (not planned) area of intentional burn in the project area in year **t**; ha
t	1, 2, 3, … **t** years elapsed since the project start date
g	G greenhouse gases (to include nitrous oxide and methane)

4 FLUX APPROACH: BASELINE AND WITH-PROJECT SCENARIOS

4.1 BASELINE ACCOUNTING

Equation 10

$$\mathbf{GHG_{bsl,t} = \Delta BG_{flux_bsl,t}}$$

WHERE

$GHG_{bsl,t}$	Annual greenhouse gas emissions in the baseline in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$\Delta BG_{flux_bsl,t}$	Annual emissions from the soil organic carbon and dead belowground biomass using the flux approach in the baseline scenario in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
t	1, 2, 3, … **t** years elapsed since the project start date

Note that change in above- and belowground biomass carbon stocks in the baseline is accounted in parameter $\Delta ABGB_{wp}$ (derived in Section 4.2.2 below) which represents the net of baseline and with project changes in above- and belowground biomass carbon stocks.

4.1.1 Emissions from Belowground in the Baseline

Emissions from belowground are estimated as a function of one or more proxy variables. Note that the emission inferred from the proxy variable(s) covers heterotrophic emissions (due to microbial respiration) from soil organic carbon and dead belowground biomass. Sequestration in live belowground (root) biomass is assessed separately, as part of parameter $\Delta ABGB_{wp}$.

Equation 11

$$\mathbf{\Delta BG_{flux_bsl,t} = \int_t (Proxy\ A_{bsl,t}, Proxy\ B_{bsl,t} \ldots) \times A}$$

WHERE

ΔBG_{flux_bsl}	Annual emissions from the soil organic carbon and dead belowground biomass pools using the flux approach in the baseline scenario in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
f_t (Proxy $A_{bsl,t}$, Proxy $B_{bsl,t,...}$)	Regression equation correlating one or more proxy variables to emissions from the soil organic carbon and dead belowground biomass at time **t**; output in MT CO_2e ha^{-1} yr^{-1}
Proxy $A_{bsl,t}$	Mean value of proxy variable **A** in the baseline at time **t**; units unspecified
Proxy $B_{bsl,t}$	Mean value of proxy variable **B** in the baseline at time **t**; units unspecified etc…
A	Project area; ha
t	1, 2, 3, … **t** years elapsed since the project start date

Note that the output of the regression equation incorporates uncertainty, derived in proportion to the root mean squared error (RMSE) of the regression (see parameter table).

The proxy variable(s) can be either measured in a valid baseline site, measured in the project area (for variables not affected by the project activity, e.g. temperature or rainfall), or modeled in the project area. If using a model (e.g. a hydrologic model) to estimate the proxy variable(s), the model(s) must be:

- Peer-reviewed
- Empirically-based
- Incorporate one or more proxy variables that are monitored ex post in the project area (e.g. precipitation)

The value(s) of parameter(s) Proxy $A_{bsl,t}$ etc. incorporate uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value (see parameter table).

Note that the cumulative emissions over time from ΔBG_{flux_bsl}, from both soil respiration and from unintentional fires in the project area (assumed to occur equally in the baseline and project scenarios), cannot exceed the total initial stock in that pool subject to oxidation, $BG_{wp,t=0}$, derived below.

Equation 12

$$\mathbf{BG_{wp,t=0} = A \times PD_{wp,t=0} \times 10,000 \times BD_{flux,wp,t=0} \times C\%_{soil} \times \left(\frac{44}{12}\right)}$$

WHERE

$BG_{wp,t=0}$	Total stocks in the soil organic carbon and belowground biomass pools in the project area at time **t=0**; MT CO_2e
$PD_{wp,t=0}$	Peat depth above low water level in the project area at time **t=0**; m
$BD_{flux,wp,t=0}$	Mean dry bulk density (as defined for flux approach, i.e. excluding coarse roots) in the project area at time **t=0**; g cm^{-3}
$\%C_{soil}$	Percentage of soil organic **C**; %
$44/12$	Ratio of molecular weight of CO_2 to carbon, MT CO_2-e MT C^{-1}
A	Project area; ha
t	1, 2, 3, … **t** years elapsed since the project start date
10,000	Converts result to units of metric tons

Therefore, if $\sum_{t=0}^{t} \Delta BG_{flux_{bsl},t} + \sum_{t=0}^{t} \Delta BG_{burn_unint,wp,t} > BG_{wp,t=0}$

Then, if $BG_{wp,t=0} - \sum_{t=0}^{t-1} \Delta BG_{flux_{bsl},t} - \sum_{t=0}^{t-1} \Delta BG_{burn_unint,wp,t} > 0$

Then $\Delta BG_{flux_{bsl},t} = BG_{wp,t=0} - \sum_{t=0}^{t-1} \Delta BG_{flux_{bsl},t}$ - $\sum_{t=0}^{t-1} \Delta BG_{burn_unint,wp,t}$

Otherwise parameter $\Delta BG_{flux_bsl,t}$ is equal to zero.

Parameter $\Delta BG_{burn_unint,wp,t}$, emissions from soil organic carbon from unintentional fire in the project scenario in year t, is derived in Section 4.2.3 below.

4.2 WITH-PROJECT ACCOUNTING

Equation 13

$$\mathbf{GHG_{wp,t} = \Delta BG_{flux_wp,t} + Net\Delta ABGB_{wp,t} + E_{BGburn_int,wp,t} + E_{AGBburn_int,wp,t}}$$

WHERE

$GHG_{wp,t}$	Annual greenhouse gas emissions in the project in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$\Delta BG_{flux_wp,t}$	Annual emissions from the soil organic carbon and dead belowground biomass using the flux approach in the project in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$Net\Delta ABGB_{wp,t}$	Annual net change in above- and belowground biomass carbon stocks in the project in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$E_{BGburn_int,wp,t}$	Emissions from soil organic carbon from intentional fire in the project scenario in year **t**; MT CO_2-e yr^{-1}
$E_{AGBburn_int,wp,}t$	Emissions from aboveground biomass from intentional fire in the project scenario in year **t**; MT CO_2-e
t	1, 2, 3, … **t** years elapsed since the project start date

4.2.1 Emissions from Belowground in the Project

Emissions from belowground are estimated as a function of one or more proxy variables. Note that the emission inferred from the proxy variable(s), ΔBG_{flux_bsl}, covers heterotrophic emissions (due to microbial respiration) from soil organic carbon and dead belowground biomass. Sequestration in live belowground (root) biomass is assessed separately, as part of parameter $\Delta ABGB_{wp}$.

Equation 14

$$\mathbf{\Delta BG_{flux_wp,t} = f_t(Proxy\ A_{wp,t}, Proxy\ B_{wp,t} \ldots) \times A}$$

WHERE

$\Delta BG_{flux_wp,t}$	Annual emissions from the soil organic carbon and dead belowground biomass using the flux approach in the project in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
f_t (Proxy $A_{bsl,t}$, Proxy $B_{bsl,t,\ldots}$)	Regression equation correlating on or more proxy variables to emissions from the soil organic carbon and dead belowground biomass pools at time **t**; output in MT CO_2e ha^{-1} yr^{-1}

Proxy $A_{wp,t}$	Mean value of proxy variable **A** in the project area at time **t**; units unspecified
Proxy $B_{wp,t}$	Mean value of proxy variable **B** in the project area at time **t**; units unspecified etc…
A	Project area; ha
t	1, 2, 3, … **t** years elapsed since the project start date

Note that the output of the regression equation incorporates uncertainty, derived in proportion to the root mean squared error (RMSE) of the regression (see parameter table).

The proxy variable(s) must be monitored in the project area. The value(s) of parameter(s) Proxy $A_{wp,t}$ etc. incorporate uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value (see parameter table).

As for the baseline, cumulative emissions over time from ΔBG_{flux_wp}, from both soil respiration and from unintentional and intentional fires in the project area, cannot exceed the total initial stock in that pool, $BG_{wp,t=0}$, derived above.

Therefore, if $\sum_{t=0}^{t} \Delta BG_{flux_{wp},t} + \sum_{t=0}^{t} \Delta BG_{burn_unint,wp,t} + \sum_{t=0}^{t} \Delta BG_{burn_int,wp,t} > BG_{wp,t=0}$

Then, if $BG_{wp,t=0} - \sum_{t=0}^{t-1} \Delta BG_{flux_{wp},t} - \sum_{t=0}^{t-1} \Delta BG_{burn_unint,wp,t} - \sum_{t=0}^{t-1} \Delta BG_{burn_int,wp,t} > 0$

Then $\Delta BG_{flux_{wp},t} = BG_{wp,t=0} - \sum_{t=0}^{t-1} \Delta BG_{flux_{wp},t}$ - $\sum_{t=0}^{t-1} \Delta BG_{burn_unint,wp,t} - \sum_{t=0}^{t-1} \Delta BG_{burn_int,wp,t}$

Otherwise parameter $\Delta BG_{flux_wp,t}$ is equal to zero.

Parameters $\Delta BG_{burn_int,wp,t}$, emissions from soil organic carbon from intentional fire in the project scenario in year t, and $\Delta BG_{burn_unint,wp,t}$, emissions from soil organic carbon from unintentional fire in the project scenario in year t, are derived in Section 4.2.3 below.

4.2.2 Emissions from Above- and Belowground Biomass in the Project

Emissions from above- and belowground biomass (in trees and shrubs) in the project, $Net\Delta ABGB_{wp}$, represent net emissions from above- and belowground biomass (i.e. net of baseline and with project) resulting from stock change in the project case relative to a baseline site. This term is set equal to zero if there is no significant difference in stock change between the project and the baseline site.

4.2.2.1 STEP 1

Measure change in stocks of above- and belowground biomass in the project area and in a baseline site. Stock change in above- and belowground biomass is measured on permanent sample plots, and represents the net of biomass increment, recruitment and mortality.

Note that in this treatment emissions due to mortality of belowground biomass (coarse roots) are double counted, as they are also included in the term, ΔBG_{flux}. This treatment is conservative, as emissions from die-off of root biomass are expected to be greater in the project (flooded) scenario, than in the baseline, and importantly, simplifies monitoring and accounting (i.e. avoids the need to separately track belowground biomass increment, recruitment and mortality).

Calculate mean annual change in stocks of above- and belowground biomass in the project area, $\Delta ABGB_{wp}$, and in a baseline site, $\Delta ABGB_{bsl}$.

Equation 15

$$\Delta ABGB_{wp,t} = \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} \left((ABGB_{wp,j,t} - ABGB_{wp,j,t-x}) \times \left(\frac{1}{x}\right) \right)$$

WHERE

$\Delta ABGB_{wp,t}$	Mean annual change in above- and belowground biomass carbon stocks in the project area in monitoring interval ending in year **t**; MT CO_2e ha^{-1} yr^{-1}
$ABGB_{wp,j,t}$	Above- and belowground biomass carbon stocks in the project area in plot **j** at time **t**; MT CO_2e ha^{-1}
$ABGB_{wp,j,t-x}$	Above- and belowground biomass carbon stocks in the project area in plot **j** at time **t-x**; MT CO_2e ha^{-1}
j	**n** sample plots
x	Number of years in monitoring interval; years
t	1, 2, 3, … **t** years elapsed since the project start date

Equation 16

$$\Delta ABGB_{bsl,t} = \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} \left((ABGB_{bsl,j,t} - ABGB_{bsl,j,t-x}) \times \left(\frac{1}{x}\right) \right)$$

WHERE

$\Delta ABGB_{bsl,t}$	Mean annual change in above- and belowground biomass carbon stocks in the baseline reference area in monitoring interval ending in year t; MT CO_2e ha^{-1} yr^{-1}
$ABGB_{bsl,j,t}$	Above- and belowground biomass carbon stocks in the baseline reference area in plot j at time t; MT CO_2e ha^{-1}
$ABGB_{bsl,j,t-x}$	Above- and belowground biomass carbon stocks in the baseline reference area in plot j at time $t-x$; MT CO_2e ha^{-1}
j	1, 2, 3 … n sample plots
x	Number of years in monitoring interval; years
t	1, 2, 3, … t years elapsed since the project start date

4.2.2.2 STEP 2

If $\Delta ABGB_{wp,t}$ is not equal to $\Delta ABGB_{bsl,t}$ (significantly different using a unpaired t test at P <0.05), then net emissions from above- and belowground biomass carbon are equal to the difference in stock change between the baseline site and the project area. Note that this term can be less than zero, where growth in the project area exceeds that in the baseline site, e.g. due to tree and shrub planting efforts conducted as part of the project activity.

Equation 17

$$Net\Delta ABGB_{wp,t} = \left((\Delta ABGB_{bsl,t} + UNC_{\Delta ABGB,bsl,t}) - (\Delta ABGB_{wp,t} - UNC_{\Delta ABGB,wp,t}) \right) \times (A - A_{burn_unint,wp,t})$$

WHERE

$Net\Delta ABGB_{wp,t}$	Annual net change in above- and belowground biomass carbon stocks in the project area in monitoring interval ending in year t; MT CO_2e ha^{-1} yr^{-1}

$\Delta ABGB_{wp,t}$	Mean annual change in above- and belowground biomass carbon stocks in the project area in monitoring interval ending in year t; MT CO_2e ha^{-1} yr^{-1}
$\Delta ABGB_{bsl,t}$	Mean annual change in above- and belowground biomass carbon stocks in the baseline reference area in monitoring interval ending in year t; MT CO_2e ha^{-1} yr^{-1}
$UNC_{\Delta ABGB,wp,t}$	Half width of 90% confidence interval exceeding 10% of the mean annual change in above- and belowground biomass carbon stocks in the project area at time t; MT CO_2e ha^{-1} yr^{-1}
$UNC_{\Delta ABGB,bsl,t}$	Half width of 90% confidence interval exceeding 10% of the mean annual change in above- and belowground biomass carbon stocks in the baseline reference area at time t; MT CO_2e ha^{-1} yr^{-1}
A	Project area; ha
$A_{burn_unint,wp,t}$	Area of unintentional burn in the project area occurring in monitoring interval ending in year t; ha
t	1, 2, 3, … t years elapsed since the project start date

If $\Delta ABGB_{wp,t}$ is not significantly different than $\Delta ABGB_{bsl,t}$, then $Net\Delta ABGB_{wp,t=0}$

4.2.3 Emissions from Fire in the Project

4.2.3.1 UNINTENTIONAL BURNS

Where unintentional burns occur in the project area, emissions from those burns are assumed, conservatively, to be equal in the project and baseline scenarios.

Net emissions from the above- and belowground biomass pool resulting from unintentional burns in the project area are excluded from accounting by delineating the area of the burn, parameter $A_{burn_unint,wp,t}$, consulting aerial imagery; see equation 17 above. Plans for intentional burns (e.g. prescribed burns) in the project area must be recorded in management records to distinguish unintentional burns (on the absence of management records). Any sample points/plots for above- and belowground biomass located within the area of an unintentional burn in the project area, will not be used to calculate change in above- and belowground biomass stocks, $\Delta ABGB_{wp,t}$, in the project area for the monitoring interval spanning the burn (i.e. from the monitoring event immediately prior to the burn to the monitoring event immediately after the burn). Emissions from the belowground pool, $\Delta BG_{flux_wp,t}$, are estimated applying a regres-

sion based on proxy variable measurements in the absence of fire, do not consider the emissions from fire and are calculated for the entire project area, using all proxy variable data, as usual.

Although emissions from unintentional fire are excluded from accounting, peat emissions from unintentional fire are tracked to update the threshold on emissions from the belowground pool; equations 12 and 14 above. Emissions from belowground (due to oxidation of peat) from unintentional burns, $\Delta BG_{burn_unint,wp,t}$, are monitored by sampling surface elevation of peat in the burned area, $A_{burn_unint,wp,t}$, and areas outside the burned area, after the burn takes place, to assess the depth of peat removed by the fire. Parameter $\Delta SE_{burn_unint,wp,t}$ incorporates uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value (see parameter table).

Equation 18

$$\Delta BG_{burn_unint,wp,t} = A_{burn_unint,wp,t} \times -\Delta SE_{burn_unint,wp,t} \times 10 \times BD_{flux,wp,t} \times EF_{peat,CO2}$$

WHERE

$\Delta BG_{burn_int,wp,t}$	Emissions from soil organic carbon from intentional fire in the project scenario in year **t**; MT CO_2-e
$\Delta SE_{burn_unint,wp,t}$	Mean surface elevation change due to unintentional fire in the project area at time **t**; mm
$BD_{flux,wp,t}$	Mean dry bulk density (as defined for flux approach, i.e. excluding coarse roots) in the project area at time **t**; g cm^{-3}
$EF_{peat,CO2}$	Emission factor for carbon dioxide; MT CO_2e emitted **×** MT dry matter peat burned^{-1}
$A_{burn_unint,wp,t}$	Area of unintentional burn in the project area occurring in monitoring interval ending in year **t**; ha
t	1, 2, 3, … **t** years elapsed since the project start date
10	Converts result to units of metric tons

4.2.3.2 INTENTIONAL BURNS

Carbon dioxide emissions from above- and belowground biomass pools resulting from intentional burns in the project are captured through monitoring parameter $\Delta ABGB_{wp,t}$, referencing

measurements collected at all sample plots above- and belowground biomass located within the project area.

GHG (carbon dioxide, nitrous oxide and methane) emissions from belowground (due to combustion of peat) from intentional burns, $EBG_{burn_int,wp,t}$, are monitored by sampling the planned burn area, using temporary surface level markers to assess emission of peat. Peat level is assessed from the markers immediately prior to and after the burn takes place. The actual intentional burned area, $A_{burn_int,wp,t}$, is determined after the burn takes place by consulting aerial imagery.

Nitrous oxide and methane emissions from the aboveground biomass pool, $EAGB_{burn_int,wp,t}$, are monitored referencing pre- and post-burn measurements of aboveground biomass from the subset of samples located within the intentional burned area, $A_{burn_int,wp,t}$.

Parameters $\Delta SE_{burn_int,wp,t}$ and $\Delta AGBA_{burn_int_wp,t}$ incorporate uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value (see parameter tables). Note that because $\Delta AGBA_{burn_int_wp,t}$ involves a subset of the total sampling network of live tree and shrub biomass plots, it may be desired to augment sampling in the intentional burn area prior to the burn to reduce uncertainty.

Equation 19

$$E_{BGburn_int,wp,t} = \sum_{g=1}^{G} (A_{burn_int,wp,t} \times -\Delta SE_{burn_int,wp,t} \times 10 \times BD_{flux,wp,t}) \times EF_{peat,g} \times GWP_g$$

WHERE

$E_{BGburn_int,wp,t}$	Emissions from soil organic carbon from intentional fire in the project scenario in year **t**; MT CO_2-e
$\Delta SE_{burn_int,wp,t}$	Mean surface elevation change in the actual area subject to intentional fire in the project area at time **t**; mm
$BD_{flux,wp,t}$	Mean dry bulk density (as defined for flux approach, i.e. excluding coarse roots) in the project area at time **t**; g cm^{-3}
$EF_{peat,g}$	Emission factor for gas **g** ; MT gas **g** emitted × MT dry matter peat burned^{-1}
GWP_g	Global warming potential for gas **g**; MT CO_2e MT gas g^{-1}
$A_{burn_int,wp,t}$	Actual (not planned) area of intentional burn in the project area in year **t**; ha
t	1, 2, 3, … **t** years elapsed since the project start date

10	Converts result to units of metric tons
g	1, 2, 3 … G greenhouse gases (to include carbon dioxide, nitrous oxide and methane)

Equation 20

$$E_{AGBburn_int,wp,t} = \sum_{g=1}^{G} (A_{burn_int,wp,t} \times -\Delta AGB_{Aburn_int,wp,t} \times 0.58) \times EF_{biomass,g} \times GWP_g$$

WHERE

$E_{AGBburn_int,wp,t}$	Emissions from aboveground biomass from intentional fire in the project scenario in year t; MT CO_2-e
$\Delta AGB_{Aburn_int,wp,t}$	Mean change in aboveground biomass carbon stocks in the actual (not planned) area of intentional burn in the project area in year t; MT CO_2e ha^{-1} yr^{-1}
0.58	Factor to convert MT CO_2e to MT dry matter biomass (assumes 0.47 MT C MT d.m.-1 and 44/12 ratio of molecular weight of CO_2 to carbon, MT CO_2-e MT C^{-1})
$EF_{biomass,g}$	Emission factor for gas g; MT gas g emitted × MT dry matter biomass $burned^{-1}$
GWP_g	Global warming potential for gas g; MT CO_2e MT gas g^{-1}
$A_{burn_int,wp,t}$	Actual (not planned) area of intentional burn in the project area in year t; ha
t	1, 2, 3, … t years elapsed since the project start date
g	1, 2, 3 … G greenhouse gases (to include nitrous oxide and methane)

5 DATA AND PARAMETERS

5.1 DATA AND PARAMETERS AVAILABLE AT VALIDATION

DATA / PARAMETER	A
DATA UNIT	Hectare (ha)
DESCRIPTION	Project area
JUSTIFICATION OF CHOICE OF DATA OR DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES APPLIED	Delineation of the project area may use a combination of GIS coverages, ground survey data, remote imagery (satellite or aerial photographs), or other appropriate data.
TREATMENT OF UNCERTAINTY	Any imagery or GIS dataset must be georegistered referencing corner points, clear land marks, or other intersection points.
COMMENTS	None

DATA / PARAMETER	$\%C_{soil_wp,t}$
DATA UNIT	%
DESCRIPTION	Percentage of soil organic C at time **t**
JUSTIFICATION OF CHOICE OF DATA OR DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES APPLIED	Soil carbon shall be determined for an aggregate sample (e.g., from 4 systematically-distributed 10 cm deep cores or auger samples) collected within a sample plot located within the project area. Note that the 10 cm depth must be referenced from the soil surface, separating the litter from the soil, referencing the same rules and procedures for determining peat surface level applied in any surface elevation measure-

	ments if using the stock change approach. This sample shall be thoroughly mixed and sieved through a 2 mm sieve to remove all non-organic material > 2 mm. Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation (e.g., allometric equations) procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: ● Be demonstrated to be un-biased and derived from representative sampling ● Minimum sample size of 20 aggregate samples ● Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) Determination of the soil organic carbon fraction (or percent soil organic carbon) should follow established laboratory procedures, such as those found in: DeLaune, R.D., K.R. Reddy, C.J. Richardson, and J.P. Megonigal, eds. 2013. Methods in Biogeochemistry of Wetlands. Soil Science Society of America Book Series No. 10. Madison, WI: Soil Science Society of America. 10004p Nelson, D.W., and L.E. Sommers. 1982. Total carbon, organic carbon, and organic matter. p. 539–580. In A.L. Page et al. (ed.) Methods of soil Analysis. Part 2. 2nd ed. Agron. Monogr. 9. ASA and SSSA, Madison, WI. Schumacher, B. A. Methods for the determination of total organic carbon (TOC) in soils and sediments. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-02/069 (NTIS PB2003-100822), 2002.
TREATMENT OF UNCERTAINTY	None
COMMENTS	The soil organic carbon fraction is sampled prior to validation and shall be used in both the baseline and with project scenario for the length of the project.

DATA / PARAMETER	f_t (Proxy A_t, Proxy B_t,...)
DATA UNIT	output in MT CO_2e ha^{-1} yr^{-1}
DESCRIPTION	Regression equation correlating one or more proxy variables to emissions from the soil organic carbon and dead belowground biomass pools
JUSTIFICATION OF CHOICE OF DATA OR DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES APPLIED	The flux approach may be employed where a regression equation correlating one or more proxy variables to belowground emissions from heterotrophic respiration, meeting the following applicability conditions is available: ● Peer-reviewed; ● Empirically-based; ● Independent variable restricted to emissions from heterotrophic respiration from the soil organic carbon and dead belowground biomass (i.e. heterotrophic respiration of litter and autotrophic respiration are excluded) pools ● Relationship between proxy variable and emissions must be significant at $P < 0.1$ and unbiased (i.e., with minimal trend in residuals) ● The study site(s) from which proxy relationship developed must include drained pocosins (as defined in Section 1.1) that have been subject to drainage/hydrological alteration for no less than 50% of the length of time that the project area has been subject to drainage/ hydrological alteration prior to project start ● Relationship incorporates one or more proxy variables that are: ◈ measured ex post in a valid baseline site, ◈ measured ex post in the project area (e.g. precipitation, temperature), and/or ◈ modeled in the project area on the basis of proxy variables monitored ex post in the project area (e.g. water table modeled from monitored precipitation) ● Uncertainty in predicted emissions (dependent variable) is known and calculated as the root mean squared error (RMSE) ● Relationship must be based on emissions assessed over at least one entire year, with frequent (at least bi-monthly) measurements

	The same relationship must be used in both the project and baseline cases. The regression may be revised based on new data, provided it meets the above requirements.
TREATMENT OF UNCERTAINTY	The output of the regression equation incorporates uncertainty where the half width of the (approximate) 90% confidence interval exceeds 10% of the predicted value, by: • In the baseline scenario, subtracting from the predicted dependent variable value the following term: root mean squared error (RMSE) of the regression x 1.67 minus 10% of the dependent variable value. • In the project scenario, adding to the predicted dependent variable value the following term: RMSE of the regression x 1.67 minus 10% of the dependent variable value
COMMENTS	If the value of any proxy variable is outside the range of values for which the relationship with emissions was determined, emissions are set equal to the predicted value corresponding to the end of the proxy variable range (closest to the actual proxy variable value). Used in flux approach only.

DATA / PARAMETER	$PD_{wp,t=0}$
DATA UNIT	Meter (m)
DESCRIPTION	Peat depth above low water level in the project area at time t=0
JUSTIFICATION OF CHOICE OF DATA OR DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES APPLIED	Low water level is defined as the low water level recorded over a period of at least one year preceding the project start date, estimated from data from a groundwater well located at the site, or if this does not exist, from the nearest USGS groundwater well, sourced from https://waterdata.usgs.gov/nwis/gw Peat depth is determined by inserting a depth rod (or series of connected depth rods) until either the low water level depth or mineral soil/bedrock is reached/the rod meets firm resistance. Note that the depth must be referenced from the soil surface, separating the litter from the soil. The parameter $PD_{wp,t=0}$ is calculated as the first quartile of the range of measured peat depths.

	Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Peat depth shall be measured at a minimum of 20 different points. • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan)
TREATMENT OF UNCERTAINTY	None
COMMENTS	Used in flux approach only.

DATA / PARAMETER	$EF_{peat,g}$
DATA UNIT	MT CO_2e emitted × MT dry matter peat burned^{-1}
DESCRIPTION	Emission factor for gas **g** (based on IPCC default values or appropriate literature sources)
JUSTIFICATION OF CHOICE OF DATA OR DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES APPLIED	Source: default values from scientific literature such as Muraleedharan et al. 2000, Christian et al. 2007, Hamade et al. 2013 or IPCC.
TREATMENT OF UNCERTAINTY	None
COMMENTS	Default values shall be updated as specified in the ACR Standard

DATA / PARAMETER	$EF_{biomass,g}$
DATA UNIT	MT gas **g** emitted × MT dry matter biomass burned^{-1}
DESCRIPTION	Emission factor for gas **g** (based on IPCC default values or appropriate literature sources)
JUSTIFICATION OF CHOICE OF DATA OR DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES APPLIED	Source: Defaults can be found in Volume 4, Chapter 2, of the IPCC 2006 Inventory Guidelines in table 2.5 (see Annex 2: emission factors for various types of burning for CH_4 and N_2O).
TREATMENT OF UNCERTAINTY	None
COMMENTS	Default values shall be updated whenever new information becomes available or new guidelines are produced by the IPCC

DATA / PARAMETER	GWP_g
DATA UNIT	MT CO_2e MT gas g^{-1}
DESCRIPTION	Global warming potential for gas **g**
JUSTIFICATION OF CHOICE OF DATA OR DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES APPLIED	Source: Default values from the latest IPCC Assessment Report. GWP for carbon dioxide = 1.
TREATMENT OF UNCERTAINTY	None
COMMENTS	Default values shall be updated per the ACR Standard

5.2 DATA AND PARAMETERS MONITORED

DATA / PARAMETER	$A_{burn_int,wp,t}$
DATA UNIT	Ha
DESCRIPTION	Actual (not planned) area of intentional burn in the project area in year **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored in project area via aerial imagery and management records. The actual intentional burned area, $A_{burn_int,wp,t}$, is determined after the burn takes place by consulting aerial imagery.
FREQUENCY OF MONITORING/ RECORDING	In the event of any intentional burn, monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not applicable
QA/QC PROCEDURES TO BE APPLIED	Any imagery or GIS dataset must be georegistered referencing corner point, clear land marks, or other intersection points.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	It is assumed that area bounds are known exactly.
COMMENTS	

DATA / PARAMETER	$A_{burn_unint,wp,t}$
DATA UNIT	ha
DESCRIPTION	Area of unintentional burn in the project area occurring in monitoring interval ending in year **t**
DESCRIPTION OF MEASUREMENT	Monitored in project area via aerial imagery and management records.

METHODS AND PROCEDURES TO BE APPLIED	The actual unintentional burned area, $A_{burn_unint,wp,t}$, is determined after the burn takes place by consulting aerial imagery. Plans for intentional burns (e.g. prescribed burns) in the project area must be recorded in management records to distinguish unintentional burns (on the absence of management records).
FREQUENCY OF MONITORING/ RECORDING	In the event of any unintentional burn, monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not applicable
QA/QC PROCEDURES TO BE APPLIED	Any imagery or GIS dataset must be georegistered referencing corner point, clear land marks, or other intersection points.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	It is assumed that area bounds are known exactly.
COMMENTS	None

DATA / PARAMETER	$ABGB_{bsl,j,t}$
DATA UNIT	MT CO_2e/ha
DESCRIPTION	Above- and belowground biomass carbon stocks in the baseline reference area in plot **j** at time **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored on baseline site via direct measurement on permanent sample plots. Procedures to monitor biomass carbon stocks, include trees and woody shrubs, shall reference a minimum value for the independent variable(s) (e.g. dbh or basal diameter) which is fixed for the project crediting period. The default carbon fraction used to estimate carbon from biomass shall be 0.47 t C t-1 d.m. in line with the IPCC default (IPCC 2006 INV GLs AFOLU Chapter 4 Table 4.3). Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling,

	measurement and estimation (e.g., allometric equations) procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence • Biomass carbon stocks shall be estimated on a minimum of 20 plots. • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) • Estimation factors (e.g. allometric equations) are demonstrated to be robust in application to the project circumstances.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years, or following a fire.
MONITORING EQUIPMENT	Measuring tape, DBH (or diameter) tape, hypsometer, clinometer
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	Uncertainty is accounted for in the parameter $UNC_{\Delta ABGB,bsl,t}$
COMMENTS	Used in flux approach only Allometric equations and root to shoot ratios shall be peer reviewed, published in a scientific journal or government publication, relevant for the geographic area where the project occurs, and appropriate for the species/vegetation type found in the project area.

DATA / PARAMETER	$ABGB_{wp,j,t}$
DATA UNIT	MT CO_2e/ha
DESCRIPTION	Above- and belowground biomass carbon stocks in the project area in plot **j** at time **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored on project area via direct measurement on permanent sample plots. Procedures to monitor biomass carbon stocks, include trees and woody shrubs, shall reference a minimum value for the independent variable(s) (e.g. dbh or basal diameter) which is fixed for the project crediting period. The default carbon fraction used to estimate carbon from biomass shall be 0.47 t C t-1 d.m. in line with the IPCC default (IPCC 2006 INV GLs AFOLU Chapter 4 Table 4.3). Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation (e.g., allometric equations) procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence • Biomass carbon stocks shall be estimated on a minimum of 20 plots. • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) • Estimation factors (e.g. allometric equations) are demonstrated to be robust in application to the project circumstances.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Measuring tape, DBH (or diameter) tape, hypsometer, clinometer

QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published hand-books, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	Uncertainty is accounted for in the parameter $UNC_{\Delta ABGB,wp,t}$
COMMENTS	Used in flux approach only. Allometric equations and root to shoot ratios shall be peer reviewed, published in a scientific journal or government publication, relevant for the geographic area where the project occurs, and appropriate for the species/vegetation type found in the project area. Any sample plots for above- and belowground biomass carbon stocks located within the area of an unintentional burn in the project area, will not be used to calculate $\Delta ABGB_{wp,t}$ in the project area for the monitoring interval spanning the burn (i.e., from the monitoring event immediately prior to the burn to the monitoring event immediately after the burn).

DATA / PARAMETER	$AGB_{bsl,j,t}$
DATA UNIT	MT CO_2e/ha
DESCRIPTION	Aboveground biomass carbon stocks in the baseline reference area in plot **j** at time **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored on baseline site via direct measurement on permanent sample plots. Procedures to monitor biomass carbon stocks, include trees and woody shrubs, shall reference a minimum value for the independent variable(s) (e.g. dbh or basal diameter) which is fixed for the project crediting period. The default carbon fraction used to estimate carbon from biomass shall be 0.47 t C t-1 d.m. in line with the IPCC default (IPCC 2006 INV GLs AFOLU Chapter 4 Table 4.3).

	Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation (e.g., allometric equations) procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence • Biomass carbon stocks shall be estimated on a minimum of 20 plots • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) • Estimation factors (e.g. allometric equations) are demonstrated to be robust in application to the project circumstances.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Measuring tape, DBH (or diameter) tape, hypsometer, clinometer
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	Uncertainty is accounted for in the parameter $UNC_{\Delta AGB,bsl,t}$
COMMENTS	Used in stock change approach only. Allometric equations shall be peer reviewed, published in a scientific journal or government publication, relevant for the geographic area where the project occurs, and appropriate for the species/vegetation type found in the project area.

DATA / PARAMETER	$AGB_{wp,j,t}$
DATA UNIT	MT CO_2e/ha
DESCRIPTION	Aboveground biomass carbon stocks in the project area in plot **j** at time **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored on project area via direct measurement on permanent sample plots. Procedures to monitor biomass carbon stocks, include trees and woody shrubs, shall reference a minimum value for the independent variable(s) (e.g. dbh or basal diameter) which is fixed for the project crediting period. The default carbon fraction used to estimate carbon from biomass shall be 0.47 t C t-1 d.m. in line with the IPCC default (IPCC 2006 INV GLs AFOLU Chapter 4 Table 4.3). Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation (e.g., allometric equations) procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence • Biomass carbon stocks shall be estimated on a minimum of 20 plots • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) • Estimation factors (e.g. allometric equations) are demonstrated to be robust in application to the project circumstances.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.

MONITORING EQUIPMENT	Measuring tape, DBH (or diameter) tape, hypsometer, clinometer
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published hand-books, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	Uncertainty is accounted for in the parameter $UNC_{\Delta AGB,wp,t}$
COMMENTS	Used in stock change approach only. Allometric equations shall be peer reviewed, published in a scientific journal or government publication, relevant for the geographic area where the project occurs, and appropriate for the species/vegetation type found in the project area. Any sample plots for aboveground biomass carbon stocks located within the area of an unintentional burn in the project area, will not be used to calculate $\Delta AGB_{wp,t}$ in the project area for the monitoring interval spanning the burn (i.e., from the monitoring event immediately prior to the burn to the monitoring event immediately after the burn).

DATA / PARAMETER	$\Delta AGB_{Aburn_int_wp,t}$
DATA UNIT	MT CO_2e ha^{-1} yr^{-1}
DESCRIPTION	Mean change in aboveground biomass carbon stocks in the actual (not planned) area of intentional burn in the project area in year **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored on project area via direct measurement on the subset of permanent sample plots located within the actual (not planned) area of intentional burn in the project area in year **t**. Measurement and monitoring procedures the same as for parameters $ABGB_{wp,j,t}$ and $AGB_{wp,j,t}$, excepting the minimum (total) sample size requirements (though see comment below regarding managing uncertainty).

FREQUENCY OF MONITORING/ RECORDING	See parameters $ABGB_{wp,j,t}$ and $AGB_{wp,j,t}$
MONITORING EQUIPMENT	See parameters $ABGB_{wp,j,t}$ and $AGB_{wp,j,t}$
QA/QC PROCEDURES TO BE APPLIED	See parameters $ABGB_{wp,j,t}$ and $AGB_{wp,j,t}$
CALCULATION METHOD	Calculate mean annual change in stocks of aboveground biomass from the subset of measurement plots located in the actual (not planned) area of intentional burn in the project area in year **t**.

Equation 21

$$\Delta AGB_{Aburn_{int_{wp},t}} = \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} \left(AGB_{wp,b,j,t} - AGB_{wp,b,j,t-x}\right) - UNC_{\Delta AGB,wp,b,t}$$

WHERE

$\Delta AGB_{Aburn_int_wp,t}$	Mean change in aboveground biomass carbon stocks in the actual area of intentional burn in the project area in year **t**; MT CO_2e ha^{-1} yr^{-1}
$AGB_{wp,b,j,t}$	Aboveground biomass carbon stocks in plot **j** located in the actual area of intentional burn in the project area in year **t**, in year **t** (post burn); MT CO_2e/ha
$AGB_{wp,b,j,t-x}$	Aboveground biomass carbon stocks in plot **j** located in the actual area of intentional burn in the project area in year **t**, in year **t-x** (pre burn); MT CO_2e/ha
j	1, 2, 3 … **n** sample plots located in the actual (not planned) area of intentional burn in the project area in year **t**
t	1, 2, 3, … **t** years elapsed since the project start date

	$UNC_{\Delta AGB,wp,b,t}$	Half width of 90% confidence interval exceeding 10% of the mean change in aboveground biomass carbon stocks located in the actual area of intentional burn in the project area in year t; MT CO_2e/ha/yr
	If $\Delta AGB_{Aburn_int_wp,t}$ is positive (i.e. there is net growth, and insignificant combustion and loss of aboveground biomass), set $\Delta AGB_{Aburn_int_wp,t}$ to zero.	
TREATMENT OF UNCERTAINTY	Parameter value incorporates uncertainty by being calculated as the mean value minus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value. Note that because this involves a subset of the total sampling network, it may be desired to augment sampling in the intentional burn area prior to the burn to reduce uncertainty.	
COMMENTS	None	

DATA / PARAMETER	$BD_{stock,wp,t}$
DATA UNIT	g cm^{-3}
DESCRIPTION	Mean dry bulk density (as defined for the stock change approach; i.e. including coarse roots) in the project area at time t
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored in the project area using cores collected from temporary or permanent sample plots. Bulk density is defined as the dry weight of the fine soil fraction and fine and coarse roots of the core divided by the core volume. Bulk density shall be sampled to a depth of 10 cm. Note that the 10 cm depth must be referenced from the soil surface, separating the litter from the soil, referencing the same rules and procedures for determining peat surface level applied in surface elevation measurements. Where roots impede coring, cut roots along the outside perimeter of the sampling ring. For bulk density determination, sample cores of known volume are collected in the field and oven dried to a constant weight at 105 C (for a minimum of 48 hours). The total sample is then weighed, then any

	coarse rocky (i.e., non-organic) fragments (>2 mm) are sieved and weighed separately. Because coarse (>2mm) rocky fragments occupy space in the soil profile in which carbon is not stored, the volume in the bulk density equation is the volume of the core. Discounting this volume, as in traditional bulk density calculations, would overestimate soil carbon stocks when applied to a volume that does not distinguish between coarse and fine fractions. Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation (e.g., allometric equations) procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Minimum sample size of 20 cores • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) Further guidance on measurement and collection approaches is provided in: DeLaune, R.D., K.R. Reddy, C.J. Richardson, and J.P. Megonigal, eds. 2013. Methods in Biogeochemistry of Wetlands. Soil Science Society of America Book Series No. 10. Madison, WI: Soil Science Society of America. 10004p
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Bulk density may be sampled using a variety of equipment.
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already

applied in national forest monitoring, or available from published hand-books, or from the IPCC GPG LULUCF 2003, is recommended.

In particular, it is essential that compaction is avoided in the process of obtaining and working with field samples. The following precautions should be adhered to:

- When obtaining the sample, particularly when trimming the end of the core to a sampling ring, avoid compressing, compacting or disturbing the sample.
- The core should be oven-dried prior to sieving.
- Large cores (approximately > 8 cm diameter) should be used preferentially; compaction tends to occur where the edge of the sampling ring meets the soil surface, and larger cores have a smaller surface to area ratio in cross section.

CALCULATION METHOD

The bulk density of the soil core is estimated as:

Equation 22

$$BD_{sample} = \frac{ODW - RF}{CV}$$

WHERE

BD_{sample}	Bulk density of the < 2 mm fine soil fraction and coarse roots, in grams per cubic centimeter (g/cm3)
ODW	Oven dry mass total sample in grams
CV	Core volume in cm^3
RF	Mass of coarse rock fragments (> 2 mm) in grams

TREATMENT OF UNCERTAINTY

None

COMMENTS

Used in the stock change approach only

DATA / PARAMETER	$BD_{flux,wp,t}$
DATA UNIT	g cm^{-3}

DESCRIPTION	Mean dry bulk density (as defined for the flux approach; i.e. excluding coarse roots) in the project area at time **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored in the project area using cores collected from temporary or permanent sample plots. Where monitoring occurs after a burn, after the initial t=0 measurement, cores will be collected from plots located outside of the area of the burn. Bulk density is defined as the dry weight of the fine soil fraction of the core divided by the core volume. Bulk density shall be sampled to a depth of 10 cm. Note that the 10 cm depth must be referenced from the soil surface, separating the litter from the soil, referencing the same rules and procedures for determining peat surface level applied in surface elevation measurements. Where roots impede coring, cut roots along the outside perimeter of the sampling ring. For bulk density determination, sample cores of known volume are collected in the field and oven dried to a constant weight at 105 C (for a minimum of 48 hours). The total sample is then weighed, then any coarse rocky (i.e., non-organic) fragments (>2 mm) are sieved and weighed separately. Because coarse (>2mm) rocky fragments occupy space in the soil profile in which carbon is not stored, the volume in the bulk density equation is the volume of the core. Discounting this volume, as in traditional bulk density calculations, would overestimate soil carbon stocks when applied to a volume that does not distinguish between coarse and fine fractions. Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation (e.g., allometric equations) procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Minimum sample size of 20 cores • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan)

	Further guidance on measurement and collection approaches is provided in: DeLaune, R.D., K.R. Reddy, C.J. Richardson, and J.P. Megonigal, eds. 2013. Methods in Biogeochemistry of Wetlands. Soil Science Society of America Book Series No. 10. Madison, WI: Soil Science Society of America. 10004p
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at the beginning of the project (t=0) and in the event of any intentional or unintentional burn, prior to the first verification event following each burn.
MONITORING EQUIPMENT	Bulk density may be sampled using a variety of equipment.
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended. In particular, it is essential that compaction is avoided in the process of obtaining and working with field samples. The following precautions should be adhered to: • When obtaining the sample, particularly when trimming the end of the core to a sampling ring, avoid compressing, compacting or disturbing the sample. • The core should be oven-dried prior to sieving. • Large cores (approximately > 8 cm diameter) should be used preferentially; compaction tends to occur where the edge of the sampling ring meets the soil surface, and larger cores have a smaller surface to area ratio in cross section.
CALCULATION METHOD	The bulk density of the soil core is estimated as: **Equation 23** $$\mathbf{BD_{sample}} = \frac{\mathbf{ODW - RF}}{\mathbf{CV}}$$ **WHERE** BD_{sample} — Bulk density of the < 2 mm fine soil fraction, in grams per cubic centimeter (g/cm^3)

	ODW	Oven dry mass total sample in grams
	CV	Core volume in cm^3
	RF	Mass of coarse rock fragments (> 2 mm) in grams
TREATMENT OF UNCERTAINTY	None	
COMMENTS	Used in the flux approach only	

DATA / PARAMETER	Proxy $A_{bsl,t}$
DATA UNIT	units unspecified
DESCRIPTION	Mean value of proxy variable A in the baseline at time **t**. The proxy variable is a measurable variable that is significantly correlated with below-ground GHG emissions.
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Either monitored via direct measurement in a valid baseline site, monitored via direct measurement in the project area, or modeled in the project area (e.g., using a hydrologic model) on the basis of one or more monitored, directly-measured proxy variables (e.g., precipitation) in the project area. When using a model (e.g., a hydrologic model) to estimate the proxy variable(s), the model(s) must be: • Peer-reviewed • Empirically-based • Incorporate one or more proxy variables that are monitored ex post in the project area (e.g., precipitation) When the variable is direct measured: Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation procedures for measuring and sampling the proxy variable are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness.

	Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence. Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan)
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not specified
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published hand-books, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	The value of parameter Proxy Absl,t incorporates uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value, as: If the parameter is positively correlated with belowground emissions (from soil organic carbon and dead belowground biomass and litter pools), the value is equal to the mean value minus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value. If the parameter is negatively correlated with belowground emissions (from soil organic carbon and dead belowground biomass and litter pools), the value is equal to the mean value plus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value. The 90% confidence interval is calculated referencing sample error (variance) for measured variables, or referencing model error for mod-eled variables.

COMMENTS	Used in flux approach only.

DATA / PARAMETER	Proxy $A_{wp,t}$
DATA UNIT	Units unspecified
DESCRIPTION	Mean value of proxy variable A in the project area at time t. The proxy variable is a measurable variable that is significantly correlated with belowground GHG emissions.
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored via direct measurement in the project area. Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation procedures for measuring and sampling the proxy variable are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan)
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not specified
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already

	applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	Not applicable
TREATMENT OF UNCERTAINTY	The value of parameter Proxy Awp,t incorporates uncertainty where the half width of the 90% confidence interval exceeds 10% of the mean value, as: If the parameter is positively correlated with belowground emissions (from soil organic carbon and dead belowground biomass and litter pools), the value is equal to the mean value plus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value. If the parameter is negatively correlated with belowground emissions (from soil organic carbon and dead belowground biomass and litter pools), the value is equal to the mean value minus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value. The 90% confidence interval is calculated referencing sample error (variance).
COMMENTS	Used in flux approach only.

DATA / PARAMETER	$\Delta SE_{bsl,t}$
DATA UNIT	mm
DESCRIPTION	Mean net surface elevation change (subsidence + peat accretion + root expansion/mortality) in the baseline site in monitoring interval ending in year **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored on baseline site via direct measurement of permanent sample points. Sample points will be located where the ground surface is measurable (necessarily outside clump centers of tussocks e.g.). Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling,

	measurement and estimation procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) Where signs of significant soil disturbance, including bioturbation, are encountered at a sample point, the disturbed sample sites must be excluded from the analysis. The change in surface elevation shall be determined using Rod Surface Elevation Tables (RSETs), Real Time Kinematic (RTKs) satellite-based approaches and/or other technologies. Use of RTK GPS should follow established field procedures, such as those found in: US Geological Survey. 2012. Topographic mapping RTK GPS standard operating procedures. Unpublished protocols. USGS, Western Ecological Research Center, San Francisco Bay Estuary Field Station, Vallejo, CA. Use of RSETs should follow established field procedures, such as those found in: Cahoon, D. R., J. C. Lynch, B. C. Perez, B. Segura, R. Holland, C. Stelly, G. Stephenson, and P. Hensel. 2002. A device for high precision measurement of wetland sediment elevation: II. The rod surface elevation table. Journal of Sedimentary Research. Vol. 72, No. 5. pp. 734-739.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	RTK GPS, RSET station, and/or other appropriate technology

QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	For each sample point, change in surface elevation is calculated as measured surface elevation at time **t** minus measured surface elevation at time **t-x** (x = length of monitoring interval in years); i.e. net subsidence is a negative value and net accretion is a positive value. Mean change in surface elevation is calculated from the sample point-level change values. Measurements of surface elevation are made in meters above sea level (masl) or meters above a reference datum to four decimal points (1/10 mm), where possible.
TREATMENT OF UNCERTAINTY	Parameter value incorporates uncertainty by being calculated as the mean value plus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value.
COMMENTS	Used in stock change approach only. The stock change approach may be employed if the following applicability conditions are met: • Net surface elevation change measured using Rod Surface Elevation Tables (RSETs), Real Time Kinematic (RTKs) satellite-based approaches and/or other technologies; • Clear and detailed rules and procedures for determining peat surface level, and distinguishing it from any overlying litter, are documented in field standard operating procedures and adhered to; • Bulk density in top 10 cm is monitored; the top layer being the aerated labile portion from which emissions are expected to be sourced, and as well is a conservative value as it's the lowest bulk density throughout the peat profile. The top 10 cm should also capture the majority of root biomass, and permit estimation of emissions from surface level change resulting from root expansion/mortality. Bulk density samples must include soil organic carbon and belowground biomass (fine and coarse roots). • Baseline site has been subject to drainage/hydrological alteration for at least 10 years (to minimize influence of new root growth and expansion on surface elevation and bulk density)

	• Repeat measurements of surface elevation change are made at the same water table level (+/- 10% of level at the time of the t = 0 measurement, as recorded at the same site(s) measured at t =0) and in the dry season. Water table level will be assessed from data from a groundwater well located at the site, or if this does not exist, from the nearest USGS groundwater well, sourced from https://waterdata.usgs.gov/nwis/gw ; • In with-project case, initial surface elevation level is measured no less than 12 months after re-wetting takes place (after initial swell has occurred); • In both the project area and baseline site, no significant erosion or sedimentation expected to occur (flat terrain, no river flow over project area); • In both the project area and baseline site, no significant compaction (by machinery or treading) expected to occur and procedures will be in place to safeguard against compaction resulting from surface elevation measurements in the field.

DATA / PARAMETER	$\Delta SE_{wp,t}$
DATA UNIT	mm
DESCRIPTION	Mean net surface elevation change (subsidence + peat accretion + root expansion/mortality) in the project area in monitoring interval ending in year **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored on project area via direct measurement of permanent sample points. Sample points will be located where the ground surface is measurable (necessarily outside clump centers of tussocks e.g.). Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence

	• Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) Where signs of significant soil disturbance, including bioturbation, are encountered at a sample point, the disturbed sample sites must be excluded from the analysis. The change in surface elevation shall be determined using Rod Surface Elevation Tables (RSETs), Real Time Kinematic (RTKs) satellite-based approaches and/or other technologies. Use of RTK GPS should follow established field procedures, such as those found in: US Geological Survey. 2012. Topographic mapping RTK GPS standard operating procedures. Unpublished protocols. USGS, Western Ecological Research Center, San Francisco Bay Estuary Field Station, Vallejo, CA. Use of RSETs should follow established field procedures, such as those found in: Cahoon, D. R., J. C. Lynch, B. C. Perez, B. Segura, R. Holland, C. Stelly, G. Stephenson, and P. Hensel. 2002. A device for high precision measurement of wetland sediment elevation: II. The rod surface elevation table. Journal of Sedimentary Research. Vol. 72, No. 5. pp. 734-739.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	RTK GPS, RSET station, and/or other appropriate technology
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	For each sample point, change in surface elevation is calculated as measured surface elevation at time t minus measured surface elevation at time **t-x** (x = length of monitoring interval in years); i.e. net subsidence is a negative value and net accretion is a positive value. Mean

	change in surface elevation is calculated from the sample point-level change values. Measurements of surface elevation are made in meters above sea level (masl) or above a reference datum to four decimal points (1/10 mm), where possible.
TREATMENT OF UNCERTAINTY	Parameter value incorporates uncertainty by being calculated as the mean value minus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value.
COMMENTS	Used in stock change approach only. The stock change approach may be employed if the following applicability conditions are met: • Net surface elevation change measured using Rod Surface Elevation Tables (RSETs), Real Time Kinematic (RTKs) satellite-based approaches and/or other technologies; • Clear and detailed rules and procedures for determining peat surface level, and distinguishing it from any overlying litter, are documented in field standard operating procedures and adhered to; • Bulk density in top 10 cm is monitored; the top layer being the aerated labile portion from which emissions are expected to be sourced, and as well is a conservative value as it's the lowest bulk density throughout the peat profile. The top 10 cm should also capture the majority of root biomass, and permit estimation of emissions from surface level change resulting from root expansion/mortality. Bulk density samples must include soil organic carbon and belowground biomass (fine and coarse roots); • Baseline site has been subject to drainage/hydrological alteration for at least 10 years (to minimize influence of new root growth and expansion on surface elevation and bulk density); • Repeat measurements of surface elevation change are made at the same water table level (+/- 10% of level at the time of the t = 0 measurement, as recorded at the same site(s) measured at t =0) and in the dry season. Water table level will be assessed from data from a groundwater well located at the site, or if this does not exist, from the nearest USGS groundwater well, sourced from https://waterdata.usgs.gov/nwis/gw ; • In with-project case, initial surface elevation level is measured no less than 12 months after re-wetting takes place (after initial swell has occurred);

	• In both the project area and baseline site, no significant erosion or sedimentation expected to occur (flat terrain, no river flow over project area); • In both the project area and baseline site, no significant compaction (by machinery or treading) expected to occur and procedures will be in place to safeguard against compaction resulting from surface elevation measurements in the field. Any sample points for surface elevation located within the area of an unintentional burn in the project area, will not be used to calculate net change in surface elevation, $\Delta SE_{wp,t}$, in the project area for the monitoring interval spanning the burn (i.e., from the monitoring event immediately prior to the burn to the monitoring event immediately after the burn).

DATA / PARAMETER	$\Delta SE_{burn_int,wp,t}$
DATA UNIT	mm
DESCRIPTION	Mean surface elevation change in the actual area subject to intentional fire in the project area at time **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored in the project area in the planned burn area, $A_{burn_int,wp,t}$, via direct measurement of temporary sample points immediately prior to and after the burn. Sample points will be located where the ground surface is measurable (necessarily outside clump centers of tussocks e.g.). Clear and detailed rules and procedures for determining peat surface level, distinguishing it from any overlying litter layer, are documented in field standard operating procedures and adhered to. Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence

	• Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) Where signs of significant bioturbation are encountered at a sample point, the disturbed sample sites must be excluded from the analysis.
FREQUENCY OF MONITORING/ RECORDING	In the event of intentional burns, monitoring shall be conducted at least every five years, or prior to each verification event if less than five years, and ensure pre- and post-burn measurements of all intentional burns occurring between verification events.
MONITORING EQUIPMENT	Measuring Tape
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published hand-books, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	For each sample point, change in surface elevation is calculated as measured surface elevation after burn minus measured surface elevation before burn; i.e. elevation change due to fire is expected to be a negative value. Mean change in surface elevation is calculated from the sample point-level change values. Measurements of surface elevation are made in meters above sea level (masl) or above a reference datum to four decimal points (1/10 mm), where possible. If $\Delta SE_{burn_int,wp,t}$ is positive (i.e. there is net accretion, and insignificant combustion and loss of peat), set $\Delta SE_{burn_int,wp,t}$ to zero.
TREATMENT OF UNCERTAINTY	Parameter value incorporates uncertainty by being calculated as the mean value minus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value.
COMMENTS	Used in flux approach only.

DATA / PARAMETER	$\Delta SE_{burn_int,wp,t}$
DATA UNIT	mm
DESCRIPTION	Mean surface elevation change due to unintentional fire in the project area at time **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Monitored in the project area via direct measurement of temporary sample points in the unintentional burn area and outside the unintentional burn area immediately after the burn. Sample points will be located where the ground surface is measurable (necessarily outside clump centers of tussocks e.g.). Clear and detailed rules and procedures for determining peat surface level, distinguishing it from any overlying litter layer, are documented in field standard operating procedures and adhered to. Acknowledging the wide range of valid monitoring approaches, and that relative efficiency and robustness are circumstance-specific, sampling, measurement and estimation procedures for measuring are not specified in the methodology and may be selected by project proponents based on capacity and appropriateness. Stratification may be employed to improve precision, but is not required. Estimates generated must: • Be demonstrated to be un-biased and derived from representative sampling • Sampling error quantified with 90% confidence • Accuracy of measurements and procedures is ensured through employment of quality assurance/quality control (QA/QC) procedures (to be determined by the project proponent and outlined in the monitoring plan) Where signs of significant bioturbation are encountered at a sample point, the disturbed sample sites must be excluded from the analysis. Surface elevation measured using Real Time Kinematic (RTKs) satellite-based approaches and/or other technologies;. Use of RTK GPS should follow established field procedures, such as those found in: US Geological Survey. 2012. Topographic mapping RTK GPS standard operating procedures. Unpublished protocols. USGS, Western Ecological Research Center, San Francisco Bay Estuary Field Station, Vallejo, CA.

FREQUENCY OF MONITORING/ RECORDING	In the event of unintentional burn(s), monitoring shall be conducted at least every five years, or prior to each verification event if less than five years, and ensure post-burn measurements of all unintentional burns occurring between verification events.
MONITORING EQUIPMENT	RTK GPS, RSET station, and/or other appropriate technology
QA/QC PROCEDURES TO BE APPLIED	Standard quality control / quality assurance (QA/QC) procedures for forest biomass/soil inventory including field data collection and data management shall be applied. Use or adaptation of QA/QCs already applied in national forest monitoring, or available from published hand-books, or from the IPCC GPG LULUCF 2003, is recommended.
CALCULATION METHOD	Mean change in surface elevation is calculated as the mean surface elevation in the burned area minus the mean surface elevation in the unburned area; i.e. elevation change due to fire is expected to be a negative value. Measurements of surface elevation are made in meters above sea level (masl) or above a reference datum to four decimal points (1/10 mm), where possible.
TREATMENT OF UNCERTAINTY	Parameter value incorporates uncertainty by being calculated as the mean value minus the amount of the half width of the 90% confidence interval exceeding 10% of the mean value.
COMMENTS	Used in flux approach only.

DATA / PARAMETER	$UNC_{\Delta ABGB,bsl,t}$
DATA UNIT	MT CO_2e/ha/yr
DESCRIPTION	Half width of 90% confidence interval exceeding 10% of the mean annual change in above- and belowground biomass carbon stocks in the baseline reference area in monitoring interval ending in year **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.

FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not applicable as calculated parameter.
QA/QC PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.
CALCULATION METHOD	Parameter $UNC_{\Delta ABGB,bsl,t}$ is calculated as:

Equation 24

$$UNC_{\Delta ABGB,bsl,t} = \left(\frac{1}{x}\right) \times 1.67 \times \sqrt{(Var_{ABGBbsl,t} + Var_{ABGBbsl,t-x} - 2 \times Cov_{ABGBbsl,t_ABGBbsl,t-x} \times \sqrt{Var_{ABGBbsl,t}} \times \sqrt{Var_{ABGBbsl,t-x}}) \times \left(\frac{1}{n}\right)}$$

$$-10\% \times \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} ((ABGB_{bsl,j,t} - ABGB_{bsl,j,t-x}) \times \left(\frac{1}{x}\right))$$

WHERE

$ABGB_{bsl,j,t}$	Above- and belowground biomass carbon stocks in the baseline reference area in plot **j** at time **t**; MT CO_2e/ha
$ABGB_{bsl,j,t-x}$	Above- and belowground biomass carbon stocks in the baseline reference area in plot **j** at time **t-x**; MT CO_2e/ha
$Var_{ABGB,bsl,t}$	Variance in above- and belowground biomass carbon stocks in the baseline reference area at time **t**; dimensionless
$Var_{ABGB,bsl,t-x}$	Variance in above- and belowground biomass carbon stocks in the baseline reference area at time **t-x**; dimensionless
$Cov_{ABGB,bsl,t_ABGB,bsl,t-x}$	Covariance in above- and belowground biomass carbon stocks in the baseline reference area at times **t** and **t-x**; dimensionless
j	1, 2, 3 … **n** sample plots
x	Number of years in monitoring interval; years

	t	1, 2, 3, … t years elapsed since the project start date
TREATMENT OF UNCERTAINTY	None	
COMMENTS	Used in flux approach only.	

DATA / PARAMETER	$UNC_{\Delta ABGB,wp,t}$
DATA UNIT	MT CO_2e/ha/yr
DESCRIPTION	Half width of 90% confidence interval exceeding 10% of the mean annual change in above- and belowground biomass carbon stocks in the project area in monitoring interval ending in year t
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not applicable as calculated parameter.
QA/QC PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.
CALCULATION METHOD	Parameter $UNC_{\Delta ABGB,bsl,t}$ is calculated as: **Equation 25** $$UNC_{\Delta ABGB,wp,t} = \left(\frac{1}{x}\right) \times 1.67 \times \sqrt{(Var_{ABGBwp,t} + Var_{ABGBwp,t-x} - 2 \times Cov_{ABGBwp,t_ABGBwp,t-x} \times \sqrt{Var_{ABGBwp,t}} \times \sqrt{Var_{ABGBwp,t-x}}) \times \left(\frac{1}{n}\right)}$$ $$-10\% \times \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} ((ABGB_{wp,j,t} - ABGB_{wp,j,t-x}) \times \left(\frac{1}{x}\right))$$

	WHERE	
	$ABGB_{wp,j,t}$	Above- and belowground biomass carbon stocks in the project area in plot **j** at time **t**; MT CO_2e/ha
	$ABGB_{wp,j,t-x}$	Above- and belowground biomass carbon stocks in the project area in plot **j** at time **t-x**; MT CO_2e/ha
	$Var_{ABGB,wp,t}$	Variance in above- and belowground biomass carbon stocks in the project area at time **t**; dimensionless
	$Var_{ABGB,wp,t-x}$	Variance in above- and belowground biomass carbon stocks in the project area at time **t-x**; dimensionless
	$Cov_{ABGB,wp,t_ABGB,wp,t-x}$	Covariance in above- and belowground biomass carbon stocks in the project area at times **t** and **t-x**; dimensionless
	j	1, 2, 3 … **n** sample plots
	x	Number of years in monitoring interval; years
	t	1, 2, 3, … **t** years elapsed since the project start date
TREATMENT OF UNCERTAINTY	None	
COMMENTS	Used in flux approach only.	

DATA / PARAMETER	$UNC_{\Delta AGB,bsl,t}$
DATA UNIT	MT CO_2e/ha/yr
DESCRIPTION	Half width of 90% confidence interval exceeding 10% of the mean annual change in aboveground biomass carbon stocks in the baseline reference area in monitoring interval ending in year **t**

DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not applicable as calculated parameter.
QA/QC PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.
CALCULATION METHOD	Parameter $UNC_{\Delta AGB,bsl,t}$ is calculated as:

Equation 26

$$UNC_{\Delta AGB,bsl,t} = \left(\frac{1}{x}\right) \times 1.67 \times \sqrt{(Var_{AGBbsl,t} + Var_{AGBbsl,t-x} - 2 \times Cov_{AGBbsl,t_AGBbsl,t-x} \times \sqrt{Var_{AGBbsl,t}} \times \sqrt{Var_{AGBbsl,t-x}}) \times \left(\frac{1}{n}\right)} - 10\% \times \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} ((AGB_{bsl,j,t} - AGB_{bsl,j,t-x}) \times \left(\frac{1}{x}\right))$$

WHERE

$AGB_{bsl,j,t}$	Aboveground biomass carbon stocks in the baseline reference area in plot **j** at time **t**; MT CO_2e/ha
$AGB_{bsl,j,t-x}$	Aboveground biomass carbon stocks in the baseline reference area in plot **j** at time **t-x**; MT CO_2e/ha
$Var_{AGB,bsl,t}$	Variance in aboveground biomass carbon stocks in the baseline reference area at time **t**; dimensionless
$Var_{AGB,bsl,t-x}$	Variance in aboveground biomass carbon stocks in the baseline reference area at time **t-x**; dimensionless

	$Cov_{AGB,bsl,t_AGB,bsl,t-x}$	Covariance in aboveground biomass carbon stocks in the baseline reference area at times **t** and **t-x**; dimensionless
	j	1, 2, 3 … **n** sample plots
	x	Number of years in monitoring interval; years
	t	1, 2, 3, … **t** years elapsed since the project start date
TREATMENT OF UNCERTAINTY	None	
COMMENTS	Used in flux approach only.	

DATA / PARAMETER	$UNC_{\Delta AGB,wp,t}$
DATA UNIT	MT CO_2e/ha/yr
DESCRIPTION	Half width of 90% confidence interval exceeding 10% of the mean annual change in aboveground biomass carbon stocks in the project area in monitoring interval ending in year **t**
DESCRIPTION OF MEASUREMENT METHODS AND PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.
FREQUENCY OF MONITORING/ RECORDING	Monitoring shall be conducted at least every five years, or prior to each verification event if less than five years.
MONITORING EQUIPMENT	Not applicable as calculated parameter.
QA/QC PROCEDURES TO BE APPLIED	Not applicable as parameter is calculated.

CALCULATION METHOD

Parameter $UNC_{\Delta AGB,wp,t}$ is calculated as:

Equation 27

$$UNC_{\Delta AGB,wp,t} = \left(\frac{1}{x}\right) \times 1.67 \times \sqrt{(Var_{AGBwp,t} + Var_{AGBwp,t-x} - 2 \times Cov_{AGBwp,t_AGBwp,t-x} \times \sqrt{Var_{AGBwp,t}} \times \sqrt{Var_{AGBwp,t-x}}) \times \left(\frac{1}{n}\right)}$$

$$-10\% \times \left(\frac{1}{n}\right) \times \sum_{j=1}^{n} ((AGB_{wp,j,t} - AGB_{wp,j,t-x}) \times \left(\frac{1}{x}\right))$$

WHERE

$AGB_{wp,j,t}$	Aboveground biomass carbon stocks in the project area in plot **j** at time **t**; MT CO_2e/ha
$AGB_{wp,j,t-x}$	Aboveground biomass carbon stocks in the project area in plot **j** at time **t-x**; MT CO_2e/ha
$Var_{AGB,wp,t}$	Variance in aboveground biomass carbon stocks in the project area at time **t**; dimensionless
$Var_{AGB,wp,t-x}$	Variance in aboveground biomass carbon stocks in the project area at time **t-x**; dimensionless
$Cov_{AGB,wp,t_AGB,wp,t-x}$	Covariance in aboveground biomass carbon stocks in the project area at times **t** and **t-x**; dimensionless
j	1, 2, 3 … **n** sample plots
x	Number of years in monitoring interval; years
t	1, 2, 3, … **t** years elapsed since the project start date

TREATMENT OF UNCERTAINTY

None

COMMENTS

Used in flux approach only.

6 CALCULATION OF ERTS

6.1 CALCULATION OF ERTS

Net accounting of GHG emission reductions is produced in Equation 28 below.

Equation 28

$$\mathbf{NER_t = GHG_{bsl,t} - GHG_{wp,t} - GHG_{lk,t}}$$

WHERE

NER_t	Annual net greenhouse gas emission reductions in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$GHG_{bsl,t}$	Annual greenhouse gas emissions in the baseline in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$GHG_{wp,t}$	Annual greenhouse gas emissions in the with-project case in monitoring interval ending in year **t**; MT CO_2e yr^{-1}
$GHG_{lk,t}$	Annual greenhouse gas emissions due to leakage in monitoring interval ending in year **t**; MT CO_2e yr^{-1}

NOTE: $GHG_{lk,t}$ = zero for all years, per applicability condition stipulating the absence of any productive land use in the project area within five years prior to the project start date.

Equation 29

$$\mathbf{ERT_t = NER_t \times (1 - BUF)}$$

WHERE

$ERT_{,t}$	Number of Emission Reduction Tons at time **t**
NER_t	Annual net greenhouse gas emission reductions in monitoring interval ending in year **t**; MT CO_2e yr-1
BUF	The non-permanence buffer deduction as calculated by the ACR Tool for AFOLU Non-Permanence Risk Analysis and Buffer Determination (BUF will be set to zero if an ACR approved insurance product is used);

DEFINITIONS

If not explicitly defined here, the current definitions in the most recent version of the American Carbon Registry (ACR) Standard apply.

Baseline	Most likely management scenario in the absence of the Project
Bulk Density	The weight of soil in a given volume. When soil core samples are collected, bulk density is calculated as the dry weight of the fine soil fraction (<2mm) of the soil cores divided by the core volume.
Drainage	Lowering water table due to deliberate hydrological manipulation, e.g. through ditching and diking
Ex-ante	"Before the event" or predicted response of Project activity
Ex-post	"After the event" or measured response of Project activity
Leakage	Leakage refers to a decrease in sequestration or increase in emissions outside project boundaries as a result of project implementation. Leakage may be caused by shifting of the activities of people present in the project area, or by market effects whereby emission reductions are countered by emissions created by shifts in supply of and demand for the products and services affected by the project.
Offset	Reduction in emissions of GHG made in order to compensate for or to offset an emission made elsewhere
Pocosin	Freshwater wetlands, with some component of broad-leaved evergreen shrubs or low trees, on organic soils in the coastal plain of southeast Virginia, North Carolina, South Carolina or Georgia, that are seasonally saturated primarily through precipitation.
Project Proponent	An individual or entity that undertakes, develops, and/or owns a project. This may include the project investor, designer, and/or owner of the lands/facilities on which project activities are conducted. The Project Proponent and landowner/facility owner may be different entities. The Project Proponent is the ACR account holder.
Rewetting	Raising the elevation of the average annual water table in drained wetland by partially or entirely reversing the pre-existing drained state;

Stratification	A standard statistical procedure to decrease overall variability of carbon stock estimates by grouping data taken from environments with similar characteristics (e.g., vegetation type, age class, hydrology, elevation)
Tool	Guideline or procedure for performing an analysis (e.g., tool for testing significance of GHG emissions in A/R CDM Project activities) or to help use or select a module or methodology.

APPENDIX A: ECOLOGIGAL LEAKAGE

Due to the unique rainfall-driven hydrology of pocosin ecosystems of the southeastern US, re-wetting of previously drained pocosins in the Atlantic coastal plain from southeast Virginia to Georgia is unlikely to result in increased GHG emissions off-site. Ecological leakage (i.e. increased emissions off-site due to the project activity), could only be envisioned in cases where water tables are lowered at a adjacent site due to reduced water export from a re-wetted project area. Because lateral movement of water from adjacent areas is not a primary input to the water budget in undrained (Richardson et al., 1980; Daniel 1980) and drained pocosins (Daniel 1980; Amataya et al., 1997), retaining water in the project area is not expected to lower water table levels, or increase GHG emissions, in adjacent areas.

Pocosins in the Southeastern US typically occupy elevated areas between coastal streams and bays, receiving little or no surface water or ground water inputs from adjacent areas (Sharitz and Gibbons 1982, McDonald et al., 1983; Kris Bass, former NCSU extension, and Howard Phillips, USFWS, personal communication, August 10, 2017). Organic peat soils characteristic of pocosins have high infiltration rates and low hydraulic conductivity (Daniel 1980), and pocosin topography is typically flat. Storm runoff that is not channelized will slowly move out of the pocosin over a broad reach of shoreline along a bordering stream or other body of water (Daniel, 1980). Thus precipitation falling on the surface of the pocosin is primarily lost to evapotranspiration without flowing to adjacent areas (Daniel 1980; Richardson and McCarthy, 1994; Amataya et al., 1997; Bass 2017), and with minimal (1%) loss to groundwater (Heath 1975). This is particularly true during the dry season (when the bulk of GHG emissions from peat oxidation occurs) when evapotranspiration can account for as much as 90% of outflow in undrained pocosins (Richardson, 2003).

Artificial drainage systems, characteristic of the landscape of drained pocosins in the southeastern US, generally collect and funnel surface runoff to a few discrete discharge points in coastal streams and bays (Daniel 1980; Tiner 2003). Where ditches are present, subsurface drainage occurs as lateral flow to field drainage ditches which conduct runoff to larger canals (Amataya et al., 1997). Runoff flowing through canals from higher areas effectively bypasses lower lying areas and flows directly to discharge points (Charles Peoples, personal communication, August 8, 2017; Phillips, H, USFWS, personal communication, August 10, 2017). Project activities that raise water table levels in drained pocosins will not lower water table levels in adjacent drained areas, because these areas receive inputs primarily from precipitation, not the project area.

Even where ditch networks are not immediately adjacent to a project area, rewetting activities in pocosins are not expected to significantly impact total outflow from the project area, because both drained and undrained pocosins receive water almost entirely from rainfall, and they lose

water primarily by evapotranspiration (Richardson et al. 1980; Sharitz and Gibbons 1982; Richardson and McCarthy 1994). Even in drained pocosins, evapotranspiration accounts for roughly 60% - 70% of outflow in the annual water budget (Richardson and McCarthy, 1994; Amataya et al., 1997; Bass 2017). Hydrologic restoration of a North Carolina pocosin decreased outflows of drainage and surface runoff by 5%, decreasing total outflow by only 1% (Bass, 2017).

In cases where water has been impounded downstream from the project area (e.g. in a pre-existing restored wetland), rewetting of the project area is likewise not expected to result in lower water table levels in the impounded area, because, again, rainfall is the primary input to any downstream site. During the dry season, evapotranspiration dominates the water budget and outflow from upstream areas is at its lowest (Bass, 2017) and re-wetting would have negligible impact on outflow. Water table levels in both the project area and downstream areas may drop in the dry season, not as a result of the project activity, but as a result of reduced rainfall inputs and higher evapotranspiration rates. Thus, rewetting of drained pocosins in the southeastern US is not expected to result in lowering of water table levels, or increases in GHG emissions, in adjacent areas, whether they are undrained, drained, or rewetted.

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The American Carbon Registry™

Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects

Version 1.0

April 2015

This methodology was developed by Blue Strategies.



Blue Strategies

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DEFINITIONS[1]

Atmospheric Leakage: Leakage of injected CO_2 from the geologic storage reservoir to the atmosphere.

Carbon Capture and Storage (CCS): The separation and capture of carbon dioxide (CO_2) from the atmospheric emissions of industrial processes or the *direct air capture (DAC)* of atmospheric CO_2 and the transport and safe, permanent storage of the CO_2 in deep underground geologic formations.

Confining Zone: Region in the subsurface above the *Storage Volume* that forms a nearly impenetrable layer to the vertical migration of CO_2.

Direct Air Capture (DAC): Process of separating and capturing CO_2 from the atmosphere.
Enhanced Oil Recovery (EOR): The process of producing hydrocarbons from subsurface reservoirs using thermal, gas, or chemical injection techniques. In this methodology, EOR concerns the injection of CO_2 to produce hydrocarbons from the reservoir.

Emission Reduction Tonne (ERT): The "ERT" is the ACR unit of exchange for tradable, project-based verified carbon offsets. ERTs refer to both emission reductions and enhancements in sequestration. ACR issues one ERT for each metric tonne of CO_2e emission reductions or removals verified against an ACR standard and methodology.

Excess CO_2 Emissions: Additional CO_2 emissions that could result from poor or negligent operation of the primary process, or from not meeting existing regulations mandating the use of certain technologies, or regulations directly controlling CO_2 emissions or other pollutant emissions which indirectly affect CO_2 emissions. Projects shall not be credited for storage of excess CO_2 emissions.

Fugitive Emissions: Emissions due to leaks from equipment such as flanges, valves, flow meters, headers, etc. These emissions can occur in the capture, transport, injection, and storage segments of the project and are calculated using procedures described in Section 4.0.

Functional Equivalence: A project and baseline are functionally equivalent if they provide the same function while delivering comparable products in quality and quantity.

Geologic Storage: The placement of CO_2 into a subsurface formation, such as an oil and gas producing reservoir or a deep saline aquifer, where it will remain safely and permanently stored.

Geologic Storage Reservoir: See *Reservoir*

Greenhouse Gas (GHG) Assessment Boundary: The greenhouse gases included in the calculation of baseline and project emissions. In this methodology these include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

[1] For additional definitions of standard terms see the latest version of the *ACR Standard.*

Invalidation: The voiding of an offset credit by ACR. In the event that and for so long as a Project Proponent has not filed a Risk Mitigation Covenant or provided an alternative risk mitigation assurance acceptable to ACR as described in Section 5.4.1, offset credits issued for the project shall be subject to invalidation by ACR in the event of an intentional reversal for which compensation is not made.

Monitoring, Reporting, and Verification (MRV) Plan: A verifiable project-specific plan which includes the monitoring and reporting requirements described in Section 5.4 of this methodology.

Oil and Gas Reservoir: See *Reservoir*

Permanence: Permanence refers to the perpetual nature of removal enhancements and the risk of reversal of a project's emissions reductions, i.e., the risk that atmospheric benefit will not be permanent. GHG removals may not be permanent if a project has exposure to risk factors, including unintentional reversals (i.e. atmospheric leakage as defined above) and intentional reversals (e.g., release of stored CO_2 that is intentional or that is a collateral effect of any planned activities affecting the storage volume). For CCS projects, the absence of atmospheric leakage during the Project Term is considered assured when it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO_2 will remain contained within the storage volume (see 5.4.1). The risk of intentional reversal is determined by an assurance that the injected CO_2 remains in the storage volume based on the post-injection monitoring strategy and post-Project Term storage requirements described in Section 5.4.

Physical Boundary: GHG emission sources included in the project.

Primary Process: The specific power generation or industrial process (e.g., natural gas processing, hydrogen production, steelmaking) creating the captured CO_2.

Primary Recovery Process: The production of hydrocarbons from the subsurface without the use of artificial methods, such as water, steam, gas or chemical injection.
Producing reservoir: See *Reservoir.*

Projection-based Baseline: 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.

Reversal: Atmospheric leakage of injected CO_2 from the *Storage Volume* that is not remediated.

Reversal Risk Mitigation Mechanism: Project Proponents shall mitigate reversal risk by contributing offset credits from the project itself to the ACR Reserve Account; contributing ACR offset credits of another type or vintage to the ACR Reserve Account; providing evidence of sufficient insurance coverage with an ACR-approved insurance product to recover any future reversal; or using another ACR-approved risk mitigation mechanism. ACR requires geologic sequestration Project Proponents to use approved methodologies that assure permanence including ongoing QA/QC and long-term monitoring and reversal risk mitigation measures as described in Section 5.4.

Reservoir: A three-dimensional confined region in the subsurface that encompasses the region containing hydrocarbons being produced.

Risk Mitigation Covenant: A covenant filed in the real property records of each county, parish and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located, prohibiting any intentional reversal (e.g., release of stored CO_2 that is intentional or that is a collateral effect of any planned activities affecting the storage volume) unless measures are taken in advance to compensate for the reversal by replacing the reversed offset credits for ACR's retirement pursuant to a plan acceptable to ACR. See section 5.4.1.

Standards-based Baseline: A baseline represented by a performance or regulatory standard, usually expressed in the form of an intensity metric (e.g., tonnes of CO_2 per megawatt hour of generated electricity).

Storage Volume: A space within the subsurface into which the project CO_2 is injected and where the injected CO_2 is stored permanently.

Venting Emissions: Emissions through dedicated vent stacks during normal operation, process upsets, or shutdowns. These emissions can occur in the capture, transport, injection, and storage segments of the project and are calculated using procedures described in Section 4.0.

1.0 BACKGROUND AND APPLICABILITY

1.1 Background on CCS Projects

Carbon capture and storage (CCS) is the separation and capture of carbon dioxide (CO_2) from the atmospheric emissions of industrial processes or the direct air capture (DAC) of atmospheric CO_2 and the transport and safe, permanent storage of the CO_2 in deep underground geologic formations. [2] [3]

In CCS, CO_2 that would otherwise have been emitted into the atmosphere or that currently resides in the atmosphere is captured and disposed of underground. By preventing CO_2 from large-scale industrial facilities from entering the atmosphere or by removing the CO_2 that currently resides in the atmosphere, CCS is a powerful tool for addressing potential climate change. Geologic storage is defined as the placement of CO_2 into a subsurface formation so that it will remain safely and permanently stored. Examples of subsurface formations include deep saline aquifers and oil and gas producing reservoirs.

The CO_2 for geologic storage comes either from industrial facilities that emit large amounts of CO_2, particularly those that burn coal, oil, or natural gas; or potentially directly from the atmosphere via large-scale chemical DAC facilities. Industrial facilities include power plants, petroleum refineries, oil and gas production facilities, iron and steel mills, cement plants, and various chemical plants.

This methodology outlines the requirements and process for CCS Project Proponents that store CO_2 in oil and gas reservoirs to qualify their projects for carbon credits under the American Carbon Registry® (ACR) program. The methodology is based on the accounting framework developed by the Center for Climate and Energy Solutions (formerly the Pew Center on Global Climate Change).[4]

1.2 Eligibility

Eligible projects under the methodology are those that capture, transport and inject anthropogenic CO_2 during enhanced oil recovery (EOR) operations into an oil and gas reservoir located in the US or Canada where it is sequestered. Figure 1-1 provides a basic schematic of a CCS project illustrating the scope of the methodology. A description of EOR is included in Appendix A.

[2] What is carbon sequestration (or carbon capture and storage)?, http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carbonseq.html

[3] The Business of Cooling the Planet, Fortune, October 7, 2011, http://tech.fortune.cnn.com/2011/10/07/the-business-of-cooling-the-planet/

[4] A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012

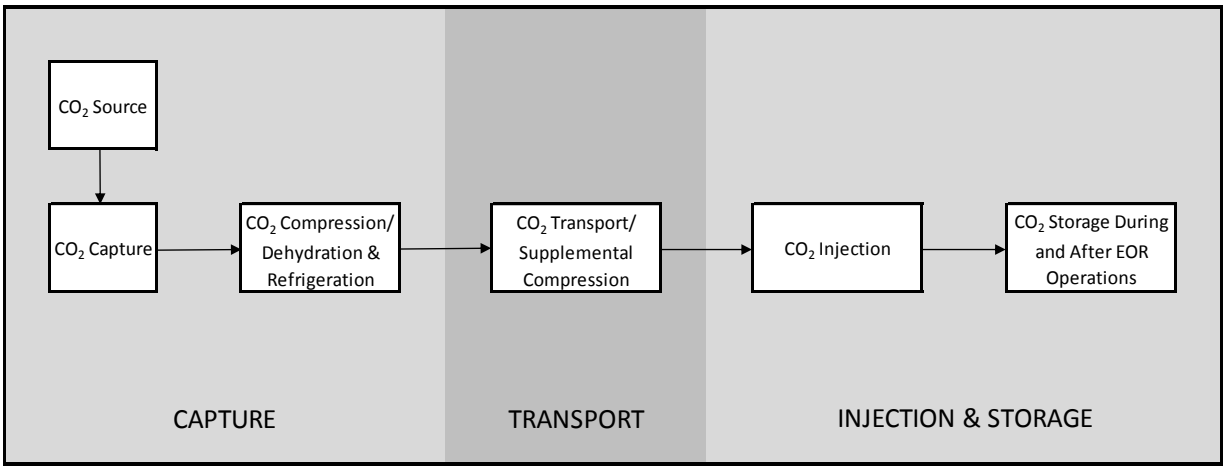


Figure 1-1 Basic CCS Project Schematic [5]

Projects are only eligible if there is clear and uncontested ownership of the pore space and, unless the Project Proponent has filed a Risk Mitigation Covenant and secured the consent of surface owners to the filing of a Risk Mitigation Covenant or provided an alternative risk mitigation assurance acceptable to ACR as described in 5.4.1, offset credits issued for a project shall be subject to Invalidation. Additionally as described in Section 6.3, Project Proponent and EOR operators shall obtain needed surface use agreements for the duration of the Project Term to conduct post-injection monitoring activities and, if necessary, remediation.

With respect to the capture of CO_2, eligible CO_2 source types include, but are not limited to: electric power plants equipped with pre-combustion, post-combustion, or oxy-fired technologies; industrial facilities (for example, natural gas production, fertilizer manufacturing, and ethanol production); polygeneration facilities (facilities producing electricity and one or more of other commercial grade byproducts); and DAC facilities.

Eligible CO_2 transport options include moving CO_2 by barge, rail, or truck from the source to the storage field, or moving the CO_2 in a pipeline.

Eligible geological storage of CO_2 for an EOR project must, at minimum, utilize Class II wells in the US and similar well requirements in Canada. Eligible projects include those where CO_2 is injected:

- to enhance production from hydrocarbon producing reservoirs that have previously produced or are currently producing through the use of primary and secondary recovery processes; or
- to produce from reservoirs that have not produced hydrocarbons through the use of primary or secondary recovery processes but have a potential for hydrocarbon recovery through CO_2 injection in the reservoir.

[5] Adapted from A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012

If projects are required to transition from Class II to Class VI wells after project registration, then those projects will remain eligible through the end of the current Crediting Period. In other words, if regulations requiring the transition from Class II to Class VI wells are enacted after the project has been registered with the ACR, then that project will continue to be eligible with Class II wells through the end of the project's current Crediting Period. The eligibility of the project during future Crediting Periods will include an assessment of whether the transition rules require conversion of the project's Class II wells to remain eligible.

1.3 Periodic Reviews and Revisions

ACR may require revisions to this methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project's activities. This methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the Project Proponent shall ensure that they are using the latest version of the methodology.

2.0 PROJECT BOUNDARIES

Consistent with *ACR Standard* requirements, the project boundary includes a physical boundary, a temporal boundary, and a greenhouse gas (GHG) assessment boundary. Figure 2-1 provides a general illustration of project boundaries, which includes the physical boundary (i.e. emission sources) and assessment boundary (i.e., the GHGs emissions from each source). In addition, project boundaries include the temporal boundary, which include the temporal parameters affecting project validity and the duration of required project activities. Physical, temporal, and assessment boundaries are discussed in the following sections.

2.1 Physical Boundary

The physical boundary demarcates the GHG emission sources included in the project and baseline emissions calculation (as presented in Section 4). In this methodology, the project boundary is intentionally drawn broadly to avoid unaccounted emissions associated with capturing and storing CO_2. Specifically it covers the full CCS process, including emissions from CO_2 capture, transport, and storage in oil and gas reservoirs, as well as CO_2 recovery and re-injection operations at EOR sites. If CO_2 is captured from more than one process, then the Project Proponent shall combine them within the boundary that encompasses the capture site.

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 physical boundary shall incorporate all GHG sources affected by the project in the baseline and project scenarios – i.e., the change in emissions due to capturing CO_2. This may require the inclusion of one or more emission sources from the Primary Process creating the captured CO_2. For example, a boundary for CO_2 capture at a hydrogen production unit within a refinery unit would encompass systems associated with the hydrogen production process but might exclude downstream units that use the hydrogen (e.g., the hydro-treating units) or other upstream systems unaffected by the CO_2 capture system.

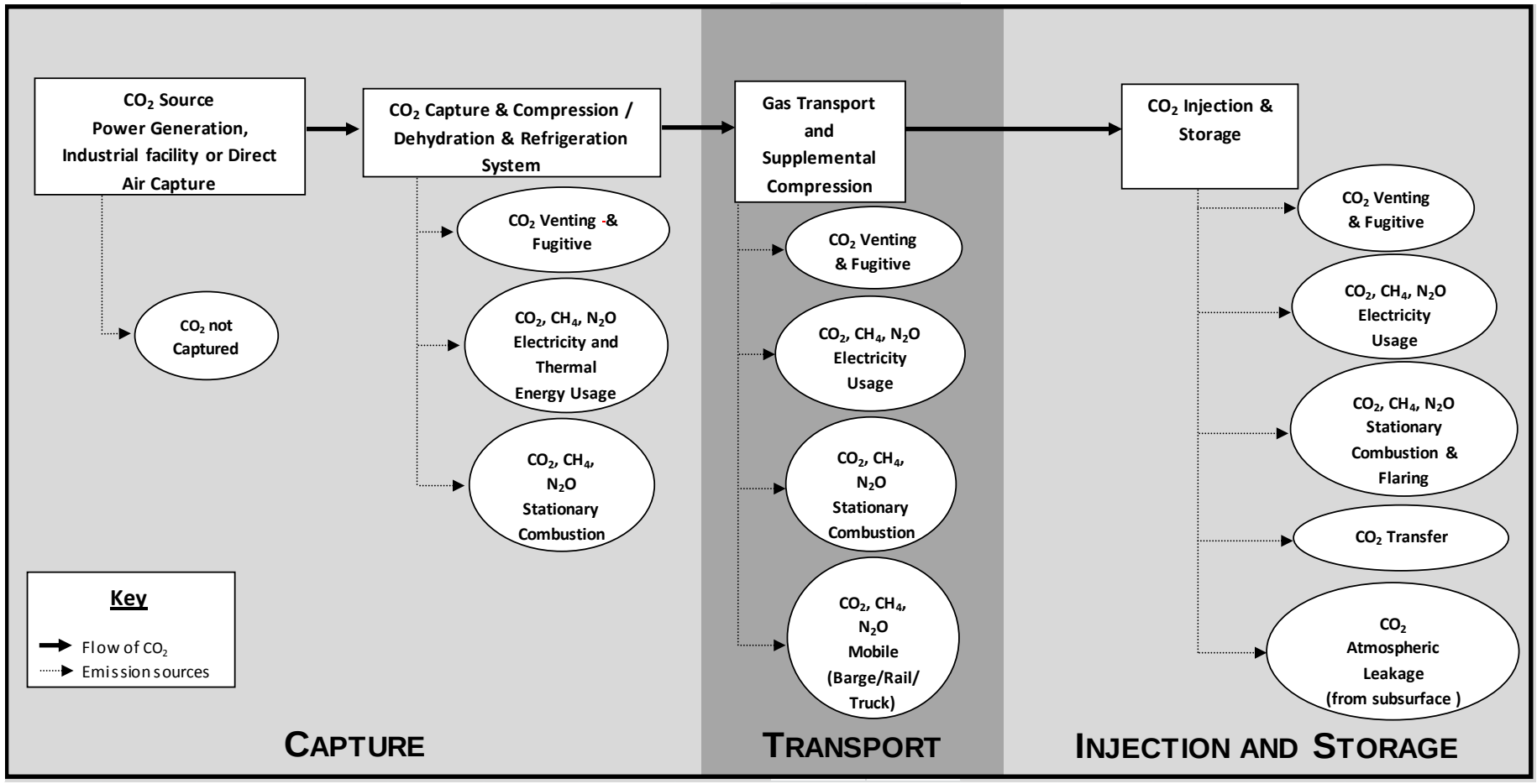


Figure 2-1 CCS Project Boundary [6]

[6] Adapted from A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012

2.2 Temporal boundary

For qualifying CCS projects, the project Start Date is January 1, 2000 or the date when the project's captured CO_2 is first injected for sequestration in the subsurface, whichever is later. For CCS projects associated with ongoing EOR operations, the sequestration site may already be utilizing CO_2 from other sources delivered through an existing CO_2 pipeline network (e.g., West Texas). In those situations, the project Start Date is the date when custody of the project's captured CO_2 is first transferred to the EOR operator.

Projects whose Start Date is more than two years prior to the date of listing on ACR must provide documentation that GHG mitigation was an objective as of the Start Date. This documentation must provide evidence, based on official, legal or other corporate documentation that was available to third parties at or prior to the Start Date of the Project Activity, that GHG mitigation and/or the sale or retirement of carbon credits was considered in the decision to proceed with the Project Activity.

Crediting Period is the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. Since qualifying CCS projects are usually long-term (30+ years) and involve significant investment in CCS infrastructure as well as for developing individual project and monitoring plans, the Crediting Period for these projects shall be ten (10) years. This period provides an adequate term during which market participants (Project Proponents, offset buyers, registries, etc.) have a level of assurance that offsets will be generated from the project as long as they are successfully verified in accordance with the project's approved GHG Project Plan. At the end of each 10-year period, the Project Proponent may apply to renew the Crediting Period by complying with all then-current ACR requirements, re-evaluating the baseline scenario, and using emission factors, tools and methodologies in effect at the time of Crediting Period renewal. ACR does not limit the allowed number of Crediting Period renewals.

The Project Term is the minimum length of time for which a Project Proponent commits to project continuance, monitoring and verification. For CCS projects the Project Term includes the period of CO_2 injection plus a time period following the end of injection during which the reservoir is monitored for atmospheric leakage. The minimum post-injection period for CCS projects is five (5) years. The duration of post-injection monitoring shall be extended beyond 5 years based on the monitoring results obtained during this 5-year period and whether no leakage of CO_2 (discussed in Section 5.4) can be assured. If no leakage of CO_2 cannot be assured based on the monitoring during this period, the Project Term will be extended in two-year increments until no leakage of CO_2 is assured.

2.3 Greenhouse Gas Assessment Boundary

The greenhouse gases included in calculations of baseline emissions and project emissions are shown in Table 2-1. The emissions associated with the combustion of hydrocarbons produced by EOR products (i.e., produced oil or gas), which occurs outside the project boundary at the point of use, are excluded. This approach is consistent with other GHG emission reduction methodologies, where emissions related

to the use of the products are not included. Moreover, oil production through EOR would most likely displace an equivalent quantity of imported oil or in some cases domestic primary (i.e., non-EOR) production.[7,8,9] The methodology encourages the domestic production of oil with a lower carbon footprint due to the simultaneous injection and storage of anthropogenic CO_2 that would otherwise be emitted to the atmosphere.

Table 2-1 Greenhouse Gases Considered in the Assessment Boundary

	Emission Source	Gas	Included?	Justification/Explanation
Baseline	Gas stream captured from the primary process	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible and exclusion is conservative
		N_2O	No	Emission is negligible and exclusion is conservative
Project	**CO_2 Capture**			
	Non-captured CO_2 from the primary process (vented and fugitive)	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible
		N_2O	No	Emission is negligible
	Stationary combustion	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Electricity and thermal energy usage	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	CO_2 Transport			
	Stationary combustion	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Vented & fugitive emissions	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible
		N_2O	No	Emission is negligible
	Electricity usage	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Mobile (Barge/Rail/Truck)	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness

[7] The most recent Energy Information Agency (EIA) data indicates that in 2011, the US produced 5.65 million barrels per day (MMbbl/d) of crude oil while importing 8.94 MMbbl/d during the same period. So any incremental increase in domestic oil production through EOR would offset an equivalent quantity of imported oil that is produced by primary production processes which do not involve CO_2 sequestration. Therefore there are no incremental emissions associated with the combustion of the produced oil.

[8] Storing CO_2 with Enhanced Oil Recovery, DOE/NETL-402/1312/02-07-08, National Energy Technology Laboratory, February 2008.

[9] Reducing Imported Oil with Comprehensive Climate and Energy Legislation, Natural Resources Defense Council, March 2010.

	Emission Source	Gas	Included?	Justification/Explanation
	CO_2 Storage			
	Stationary combustion	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Vented & fugitive emissions from surface facilities	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	No	Not contained in source emissions
	Electricity usage	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Produced gas transferred outside project boundary	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible
		N_2O	No	Emission is negligible
	Atmospheric leakage of CO_2 emissions from the geologic reservoir	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible
		N_2O	No	Emission is negligible

3.0 BASELINE DETERMINATION

3.1 Baseline Description

The project baseline is a counterfactual scenario that forecasts the likely stream of emissions or removals that would occur if the Project Proponent does not implement the project, i.e., the "business as usual" case. It serves as a reference case against which to quantitatively compare the GHG emissions associated with the project and derive net emission reductions. In this and other sections of this document the discussions are focused on power plants as an example. CO_2 sourced from other industrial sources and used for EOR equally qualify. Further, there could be more than one source of CO_2 used for EOR by the project.

The methodology presents two baseline options, referred to as Projection-based and Standards-based.

3.1.1 Baseline Options for CCS Projects

A Project Proponent 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 4.1.2 and 4.1.3:

Projection-based baseline	Baseline Equation 4.1
Standards-based baseline	Baseline Equation 4.2

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.

For most CCS projects, the Projection-based baseline scenario will apply. According to the calculation approach, the Project Proponent will 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 in the project condition to represent the quantity of emissions prevented from entering the atmosphere.

Standards-based. The Standards-based baseline can be based on a technology or specified as an intensity metric or performance standard (e.g., tonnes of carbon dioxide equivalent [tCO_2e] per unit of output). 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-fired 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 tonnes CO_2/megawatt hour [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 approved emissions rate. In the case of hydrogen production required for refining operations, a steam methane reformer (SMR) hydrogen production facility could be represented in the standards baseline by a catalytic reformer which produces less CO_2 compared to SMR hydrogen production.

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.

A performance standard could be set by regulation for a particular sector. If the quantity of CO_2 captured and stored exceeds this standard then those excess reductions would qualify under the methodology (assuming other requirements are met). For example, if CCS enabled a new or modified facility to reduce its emissions to 800 lbs/MWh, which exceeds a regulatory performance standard requirement of 1,000 lbs/MWh, then under a performance standard approach, the baseline would be set at 1,000 lbs/MWh (mandated by regulation) and the difference of 200 lbs/MWh would be eligible for credits under the methodology.

If both baseline options are feasible for a given project, the more conservative option (i.e. the option likely to result in a lower estimate of baseline emissions and therefore a lower estimate of net emission reductions) shall be selected unless justification can be presented, acceptable to ACR and the validator, why the less conservative option represents a more credible and likely baseline scenario.

3.1.2 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 regulations 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 Proponent. 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 Proponents could decide that an emissions performance standard best represents its project circumstances and adopt a Standards-based baseline.

Current regulations shall be considered in determining whether to use a Projection-based or Standards-based baseline for new and existing sources. For example, for new sources, if a GHG regulation requires new sources to meet an emissions performance benchmark, the Standards-based baseline is appropriate and baseline emissions rate shall be set to the this benchmark. For existing sources, a Projection-based baseline is appropriate unless there is some regulation that makes it unlikely that existing source can continue operating as in the past, and is likely to be replaced by a new source having to meet the benchmark.

3.2 Additionality Assessment

Emission reductions from the project must be additional, or deemed not to occur in the business-as-usual scenario. The assessment of additionality shall be made based on evaluating the project using the performance standard approach as described below. Project Proponents utilizing this methodology shall consult the latest version of the *ACR Standard*, which may be updated from time to time.

To qualify as additional, the project must

- Pass a regulatory additionality test; and
- Exceed a performance standard

3.2.1 Surplus to Regulations (Regulatory Surplus Test)

In order to pass the regulatory surplus test, a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect now, or as of the project Start Date, that directly or indirectly affect the credited GHG emissions associated with a project.

The Project Proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated with the capture and/or sequestration of

CO_2. Voluntary agreements without an enforcement mechanism, proposed laws or regulations, optional guidelines, or general government policies are not considered in determining whether a project is surplus to regulations.

As noted in Section 3.1.1, if the quantity of CO_2 captured and stored exceeds the requirements imposed by regulation, then those excess reductions are considered surplus and thereby qualify under the methodology (assuming other requirements are met). For example, if CCS enables a new or modified facility to exceed a regulatory performance standard requirement of 1,000 lbs/MWh, then the reductions down to 1,000 lbs/MWh would not be creditable (since mandated by regulation) but those reductions in excess of the requirement are considered surplus and are creditable.

Projects that are deemed to be regulatory surplus are considered surplus for the duration of their Crediting Period. If regulations change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal, but does not affect its additionality during the current Crediting Period.

EOR sites must remain in compliance with State and Federal regulations that are in place at the time of project registration and remain in compliance with those regulations through the injection period. The injection site shall continue to remain in compliance with those regulations during the post injection period until the end of the Project Term.[10]

3.2.2 Exceeds a Performance Standard

Projects are required to achieve a level of performance that, with respect to emission reductions or removals, or technologies or practices, is significantly better than average compared with similar recently undertaken practices or activities in a relevant geographic area. The performance threshold may be:

- *Practice-based*: developed by evaluating the adoption rates or penetration levels of a particular practice within a relevant industry, sector or subsector. If these levels are sufficiently low that it is determined the project activity is not common practice, then the project activity is considered additional.
- *Technology standard*: installation of a particular GHG-reducing technology may be determined to be sufficiently uncommon that simply installing the technology is considered additional.
- *Emissions rate or benchmark* (e.g., tonnes of CO_2e emission per unit of output): with examination of sufficient data to assign an emission rate that characterizes the industry, sector or subsector, the net GHG emissions/removals associated with the project activity, in excess of this benchmark, may be considered additional and credited.

[10] While Project Proponents may choose to not renew the project's Crediting Period under new regulations, to maintain qualification of offset credits that have already been credited, the EOR site must continue to comply with regulations that were in effect at project registration through the Project Term.

Qualifying CCS projects are those that include the capture, transport, and storage of anthropogenic CO_2 in oil and gas reservoirs. Table 3-1 shows the number of operating power, gas processing, ethanol, hydrogen, ammonia, and ethylene oxide production plants that emit an estimated 6.7 million metric tonnes per day of CO_2 into the atmosphere. There is one power plant with commercial-scale CCS that is currently in full operation, and only a small fraction of the gas processing, ethanol, ammonia, and ethylene oxide plants have CCS technologies. The volumes of anthropogenic CO_2 sourced from gas plants and used for EOR are greater than from other sources because of the proximity of gas plants to oil and gas fields. Yet there are only 8 out of a total of 516 gas plants that are currently supplying CO_2 for use in EOR, which is indicative of low penetration rates in this industrial sector. In total only 16 of more than 3,700 industrial facilities currently have CCS. For some sources (e.g. power plants) that emit low concentrations of CO_2, there is significant research being undertaken to develop various types of capture technologies.

Table 3-1 Industrial Plants in the US with CCS[11,12,13,14,15,16,17,18,19]

Anthropogenic CO_2 Emission Source	No. of Plants	Estimated CO_2 Emissions (1,000 Metric tonnes per day)	No. of Plants with CCS
Fossil fuel-fired Power Plants	2,802	6,254	1
Gas Processing Plants	516	230	8
Ethanol Plants	210	100	2
Hydrogen Plants (non-refinery)	74	25	1
Hydrogen Plants (refinery)	70	55	0
Ammonia Plants	27	28	3
Ethylene Oxide Plants	10	7	1
TOTAL	**3,709**	**6,699**	**16**

Data on current injection rates of CO_2 during EOR operations in the US were reviewed to quantify adoption rates of anthropogenic CO_2 sequestration in the US.

Figure 3-2 shows the existing CO_2 pipeline system in the US that has evolved over the last thirty-five years. The network connects natural and anthropogenic sources of CO_2 to the following oil producing regions:

[11] The Emissions & Generation Resource Integrated Database for 2014, (EGRID2014), U.S. Environmental Protection Agency, February 2014
[12] Global CCS Institute Project Database, March 2015
[13] Natural Gas Processing Plants in the United States: 2012 Update, US Energy Information Administration, October 2012
[14] US Energy Information Administration at http://www.eia.gov/electricity/annual/html/epa_09_01.html
[15] Biorefinery locations at http://ethanolrfa.org/bio-refinery-locations/,January 8,2015
[16] Hydrogen Plants: Oil & Gas Journal, Worldwide Refining Survey, December 18, 2006
[17] Ammonia Plants: ICIS Chemical Business, Chemical Profile, Ammonia, October 27-November 28, 2008
[18] http://ammoniaindustry.com/ammonia-plants-in-north-america/
[19] Ethylene Oxide: ICIS Chemical Business, Chemical Profile: Ethylene Oxide, June 11-17, 2007

- Permian Basin in Texas and New Mexico
- Gulf Coast Basin including Mississippi, Alabama, Louisiana and Texas
- Rocky Mountain area of Wyoming and Colorado comprising the Powder River, Wind River, Great Divide, Washakie and Piceance Basins
- Williston Basin in Montana and North Dakota, and
- Midcontinent area of Kansas, Oklahoma and the Texas Panhandle

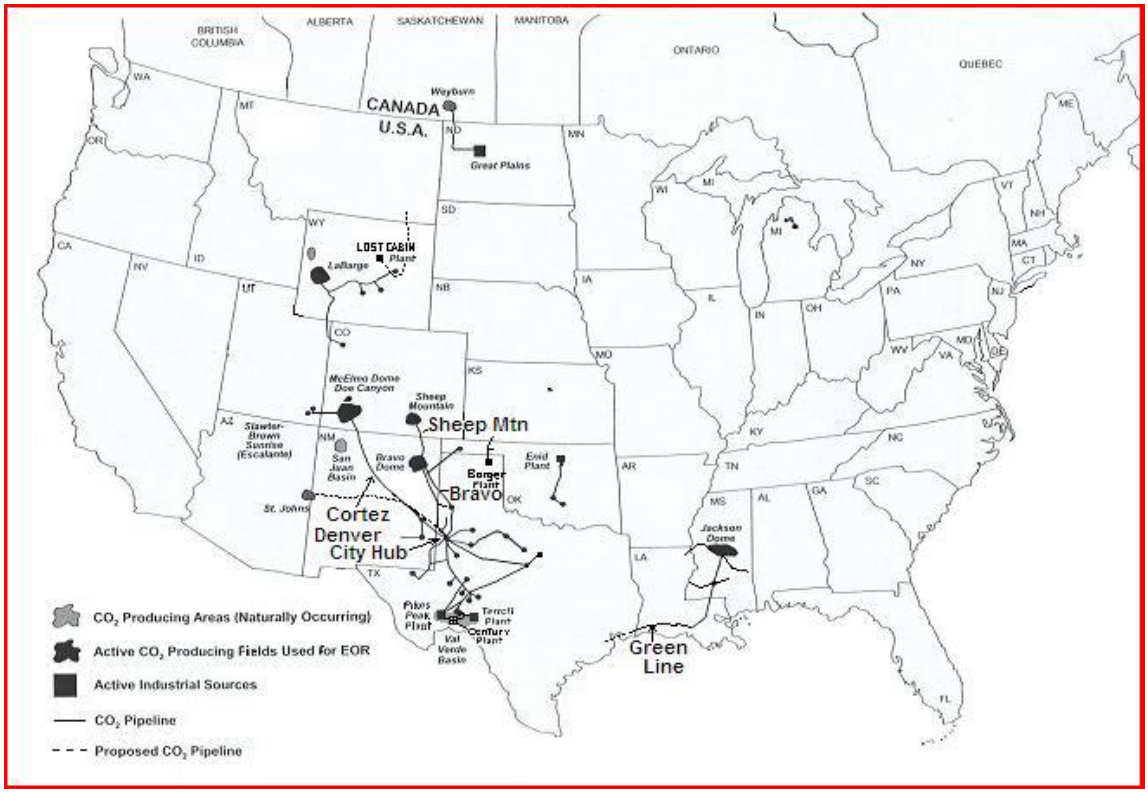


Figure 3-1 Major US CO_2 Pipelines [20]

Table 3-2 provides a listing of these major sources of CO_2. Total CO_2 usage rates from both natural and anthropogenic sources are 6 billion cubic feet per day (bcfd). It includes approximately 72 percent or 2.6 bcfd obtained from natural sources with the remaining 28 percent or 1.03 bcfd being captured from anthropogenic sources.

The current anthropogenic CO_2 usage rate of 1.03 bcfd (54,000 metric tonnes per day) is significantly small (~0.8 percent) when compared to the estimated total of 6.7 million metric tonnes per day of anthropogenic CO_2 that is emitted to the atmosphere from the industrial sources listed in Table 3-1. It indicates that the penetration levels for the practice of using anthropogenic CO_2 for EOR are extremely low.

[20] A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide, Topical Report, IOGCC, September 10, 2010

The data in Tables 3-1 and 3-2 indicates that the adoption rates of CCS capture technologies for industrial sources as a whole and for individual source types are extremely low, and the injection of anthropogenic CO_2 in hydrocarbon reservoirs during EOR is not common practice.

Table 3-2 US Natural and Anthropogenic Sources of CO_2 for EOR[21]

Sources	Usage Rates	
	Million standard cubic feet per day (MMscfd)	**1,000 metric tonnes per day***
Natural Sources (Domes)		
Mc Elmo Dome	1,200	62
Bravo & West Bravo Dome	290	15
Sheep Mountain & La Veta	50	3
Jackson Dome	950	49
Doe Canyon	110	6
Subtotal	**2,600**	**135**
Anthropogenic Sources		
Power Plants (1)	244	13
Natural Gas Plants (8)	457	24
Coal Gasification	150	8
Ammonia Plants (3)	100	5
Ethylene Plant (1)	5	0.3
Ethanol Plants (2)	23	1.2
Hydrogen Plant (1)	53	2.8
Subtotal	**1,032**	**54**
Total CO_2 Sources for EOR	**3,632**	**189**

*Conversion factor:19,300 scf/metric tonne

Currently, there are no commercial scale DAC facilities. This technology is in various stages of bench-scale and pilot-scale development and testing.

Based on these low penetration rates, it can be concluded that CCS projects meet a practice-based performance standard and can be considered additional as long as they are not required by regulation.

The penetration rates on which this practice-based performance standard is based will be reassessed periodically after significant changes to the market, or, at a minimum, every 10 years. ACR reserves the right to review the performance standard as necessary to ensure additionality of future projects. All GHG Project Plans for new projects, and all applications for Crediting Period renewal on existing

[21] Follow the CO_2, How Sources of CO_2 Define Deployment Scenarios for Enhanced Oil Recovery, US DOE, NETL,, presented at the Permian CCS Forum, April 4, 2012

projects, shall apply the regulatory surplus and practice-based performance standard tests in the latest approved revision of this methodology in effect at the time of GHG Project Plan submission or application for Crediting Period renewal.

4.0 QUANTIFICATION METHODOLOGY

This section details the methods and equations to quantify baseline emissions, project emissions, and emission reductions. These procedures and equations have been adapted from the accounting framework developed by the Center for Climate and Energy Solutions.[22] Project Proponents shall determine which equations apply to their project based on an evaluation of project and baseline configurations and on project-specific conditions. Figure 2-1 and Table 5-2 can be used as an aid in this determination. Supplemental quantification methods are included in Appendix B.

4.1 Baseline Emissions

Two approaches can be used 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.

4.1.1 Functional Equivalence

The principle of functional equivalence dictates that the project and baseline shall provide the same function while delivering comparable products in quality and quantity. In the case of CCS projects, 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 Proponent 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.

For example, in some project configurations, incremental emissions associated with operating 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 Proponent uses actual electricity production data to derive baseline emissions, it could underestimate baseline emissions.

[22] A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012

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 Proponents shall 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.

In some cases, baseline emissions may have to be modified to ensure that projects are not being credited for capture and storage of excess CO_2 emissions, i.e., additional CO_2 emissions that could result from poor or negligent operation of the primary process, or from not meeting existing regulations mandating the use of certain technologies, or regulations directly controlling CO_2 emissions or directly controlling other pollutant emissions which indirectly affect CO_2 emissions. The Project Proponent shall provide evidence that the primary process facility was built and is being operated in accordance with its permit requirements and that there were no violations of process conditions or exceedances in emissions of CO_2 and other pollutants. If a violation occurred then the effect on CO_2 emissions shall be evaluated and any increases in CO_2 over normal operations for that time period will be deducted from baseline emissions.

4.1.2 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, measured 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. Project Proponents would determine the appropriate way to correct measured CO_2 emissions on a project-by-project basis and justify to the validation/verification body (VVB) how the adjustment factors applied have maintained functional equivalence between the baseline and project scenarios.

For DAC facilities, baseline emissions are determined from the volume of gas and its CO_2 concentration measured at a suitable location in the capture process.

As provided in Equation 4.1, for combustion processes the mass of CO_2 could be determined from flue gas volume and composition measurements.

Equation 4.1: Total Annual Projection-based Baseline GHG Emissions

$$BE_{Projection\text{-}Based,\ y} = (Vol._{Gas\ Produced,\ y} - Vol._{excess\ CO2}) \times \%CO_2 \times \rho CO_2 \times AF$$

Where,

$BE_{Projection\text{-}Based,\ y}$	=	Baseline emissions for a CCS project where the baseline scenario is defined using a Projection-based approach in each year (tCO_2/yr).
$Vol._{Gas\ Produced,\ y}$	=	Volume of actual CO_2 gas produced from the primary process, metered at a point immediately downstream of the primary process, or for DAC facilities the volume of the captured gas measured at a suitable location in the process; volume measured at standard conditions, in each year (m^3 gas/yr).
$Vol._{excess\ CO2,\ y}$	=	Volume of excess CO_2 gas produced from the primary process due to permit violations (if any) as discussed in Section 4.1; estimated 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, or for DAC facilities monitored immediately downstream of the captured gas volume measurement location, in each year (% volume).
ρCO_2	=	Density of CO_2 at standard conditions = 0.00190 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).[23] 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 $Vol._{Gas\ Produced,\ y}$ CO_2 term, then insert 1 (one) for this term. This term is also equal to 1 (one) for DAC facilities. Note: GHG emissions from the capture system are still attributable to the project activity and have to be quantified and included in project emissions as discussed in 4.2.1.

4.1.3 Calculation Procedure for Standards-based Baseline

The Standards-based baseline is calculated by multiplying an emissions intensity metric or rate-based 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, etc.), as provided in Equation 4.2.

[23] This variable is included to maintain functional equivalence between the baseline and project.

An applicable performance standard may be set by regulation based on the type of facility generating the captured CO_2 emissions. Procedures for collecting data from the actual project to determine the output value used to calculate baseline emissions shall be set to ensure that the quantified emissions reductions appropriately represent the impact of the CCS project.

For example, in 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, the Project Proponent shall use gross electricity production as the output instead of net electricity production.

Equation 4.2: Total Annual Standards-based Baseline Emissions

$$BE_{Standards\text{-}based} = BE_{performance\ standard} \times Output_{y}$$

Where,

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

4.2 Project Emissions

CCS project emissions equal the sum of CO_2e emissions from CO_2 capture, transport, and storage, as shown in Equation 4.3.

Equation 4.3: Total Project Emissions

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

Where,

PE_{y}	=	Project emissions from CCS project in year y (tCO_2e/yr).
$PE_{Capture,\ y}$	=	Project emissions from CO_2 capture and compression in year y (tCO_2e/yr). Refer to Section 4.2.1.
$PE_{Transport,\ y}$	=	Project emissions from CO_2 transport in year y (tCO_2e/yr). Refer to Sections 4.2.2. and 4.2.3.
$PE_{Storage\text{-}P,\ y}$	=	Project emissions from CO_2 injection and storage in year y (tCO_2e/yr). Refer to Sections 4.2.4 and 4.2.5.

4.2.1 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. 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 is transferred to the pipeline operator.

The following equation 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.

Equation 4.4: Total Annual Project Emissions from the Capture Segment

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

Where,

$PE_{Capture,\,y}$	=	Project emissions from CO_2 capture and compression in each year (tCO_2e/yr).
$PE_{C\text{-}PP,\,y}$	=	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 4.5.
$PE_{Comb,\,y}$	=	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 4.6.
$PE_{Indirect\ Energy,\,y}$	=	Project emissions from purchased electricity and thermal energy used to operate the CO_2 capture and compression systems in each year (tCO_2e/yr). Refer to Equation 4.7.

Consistent with the objective of providing 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.

The following equations account for the portion of CO_2 generated from the primary process that is not captured but emitted to the atmosphere. Project Proponents 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 5-3 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 4.5 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 4.5a.[24]
$CO_2e\ Produced_{PP,y}$	=	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 4.5b.
$CO_2\ Transferred_{PP,y}$	=	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 Equation 4.5c.

[24] 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.

Equation 4.5a: Primary Process CO_2 Emissions[25]

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

Where,

$\mathbf{CO_2\ Produced_{PP,\,y}}$	=	Total CO_2 produced from the primary process in each year (tCO_2/yr).
$\mathbf{Vol._{Gas\ Produced,\,y}}$	=	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).
$\mathbf{\%CO_2}$	=	% CO_2 in the gas stream, measured immediately downstream of the primary process, at standard conditions, each year (% volume).
$\mathbf{\rho CO_2}$	=	Density of CO_2 at standard conditions = 0.00190 metric ton/m^3.

Equation 4.5b: Primary Process CH_4 and N_2O Emissions[26] [27]

$$\mathbf{CO_2e\ Produced_{PP,\,y} = \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times CH_4\text{-}GWP + \sum(Fuel_i \times EF\ N_2O_{Fuel\ i}) \times N_2O\text{-}GWP}$$

Where,

$\mathbf{CO_2e\ Produced_{PP,\,y}}$	=	Gross amount of CH_4 and N_2O produced from the primary process in each year (tCO_2/yr).
$\mathbf{Fuel_i}$	=	Total volume or mass of fuel, by fuel type i, input into the primary process in year each (e.g., m^3 or kg).
$\mathbf{EF\ CH_{4\ Fuel\ i}}$	=	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
$\mathbf{EF\ N_2O_{Fuel\ i}}$	=	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/kg of fuel).
$\mathbf{CH_4\text{-}GWP}$	=	Global Warming Potential of CH_4.[28]
$\mathbf{N_2O\text{-}GWP}$	=	Global Warming Potential of N_2O.

[25] See Appendix B 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.
[26] Applicable to CO_2 capture projects which combust fossil fuels in the primary process.
[27] CH_4 and N_2O emissions from combustion of fossil fuels are calculated from stationary source combustion emission factors, available at www.epa.gov/climateleaders/guidance/ghg-emissions.html
[28] Refer to the ACR Standard for respective GWPs.

Equation 4.5c: CO_2 Captured and Input into CO_2 Transport Pipeline

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

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.$_{Gas\ Transferred,\ y}$	=	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 = 0.00190 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, and 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 (which would not occur in the baseline scenario).

Ultimately, GHG emissions from energy use will depend on the configuration of the capture and compression facilities, 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 4.6: Capture Site Emissions of CO_2, CH_4, and N_2O from Stationary Combustion Associated with Auxiliary Equipment [29]

$$PE_{C\text{-}Comb,\,y} = \sum(Fuel_i \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times CH_4\text{-}GWP + \sum(Fuel_i \times EF\ N_2O_{Fuel\ i}) \times N_2O\text{-}GWP$$

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).
CH_4-GWP	=	Global Warming Potential of CH_4.
N_2O-GWP	=	Global Warming Potential of N_2O.

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.

Indirect emissions associated with purchased energy inputs used to operate the CO_2 capture and compression processes may need to be quantified according to equations 4.7, 4.7a, 4.7b, and 4.7c. Table

[29] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

5-3 provides the monitoring parameters to calculate CO_2 emissions from purchased and consumed electricity, steam and heat.

Emission Factor for Electricity Generation ($EF_{Electricity}$)

In Equation 4.7a, the emission factor for electricity generation is determined using data from the USEPA's Emissions & Generation Resource Integrated Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of electric power generated in the United States, including emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide, net generation, resource mix, and other attributes.[30] As of adoption of this methodology, the latest release is the Ninth Edition, version 1.0, containing data through 2010. The latest published version of eGRID shall always be used.

eGRID's Ninth Edition provides data organized by power control area (PCA), North American Electric Reliability Corporation (NERC) region, eGRID subregion, U.S. state, and other levels of aggregation. The PCA, eGRID subregion, and NERC region data are based on electricity generation, transmission and distribution areas, so effectively represent the emissions associated with the mix of GHG-emitting and non-emitting resources used to serve electricity loads in those areas.

The Project Proponent shall use emission factors from the latest version of eGRID available. The Proponent shall download, from the eGRID website, the data files spreadsheet. For eGRID Ninth Edition Version 1.0, this is called "eGRID_9th edition_V1-0_year_2010_Data.xls". Note the "Contents" tab shows the various levels of aggregation included in the other spreadsheet tabs.

The emission factor is selected in the order of preference below; i.e. if the PCA can be identified the emission factor from this tab must be used. Only if it is not possible to use the preferred level of aggregation is it permitted to move to the next level.

1. In eGRID Ninth Edition version 1.0, the PCAL10 tab has data for 119 Power Control Areas across the United States. This methodology considers those PCA emission factors to be the most precise representation of emissions and thus requires the PCA emission rate to be used as long as the PCA can be identified. In the PCAL10 tab, look up the appropriate PCA in the left-hand column and scroll across to the column entitled "PCA annual CO_2 equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO_2e/MWh.
2. If the PCA is not known, use the eGRID subregion data in the SRL10 tab. This includes emission factors for 26 eGRID subregions covering the United States. Look up the appropriate eGRID subregion in the left-hand column and scroll across to the column entitled "eGRID subregion annual CO_2 equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO_2e/MWh.
3. If the PCA is not known and it is not feasible to place the project site definitively in an eGRID subregion (e.g. because it is located near a boundary between two subregions), use the data

[30] See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

aggregated by U.S. state in the ST10 tab. This will be the least precise because electricity generation, transmission and distribution regions do not follow state boundaries. Look up the state where the project site is located in the left-hand column and scroll across to the column entitled "State annual CO_2 equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO_2e/MWh.

Equation 4.7: CO_2 Emissions from Purchased and Consumed Electricity, Steam, and Heat

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

Where,

$PE_{C\text{-}Indirect\ Energy,\ y}$	=	Project emissions from purchased electricity and thermal energy used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
$PE_{Elec,\ y}$	=	Project emissions from grid electricity used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr). Refer to Equation 4.7a.
$PE_{Cogen,\ y}$	=	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). Refer to Equation 4.7b.

Equation 4.7a: CO_2 Emissions from Purchased and Consumed Electricity

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

Where,

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

Equation 4.7b: CO_2, CH_4, N_2O Emissions from Purchased and Consumed Steam and /or Heat[31]

$$PE_{Cogen,\,y} = \sum(Fuel_i \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times CH_4\text{-}GWP + \sum(Fuel_i \times EF\ N_2O_{Fuel\ i}) \times N_2O\text{-}GWP$$

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 4.7c.
$EF\ CO_{2\ Fuel\ i}$	=	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).
CH_4-GWP	=	Global Warming Potential of CH_4.
N_2O-GWP	=	Global Warming Potential of N_2O.

[31] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

Equation 4.7c: Apportionment of Cogeneration Emissions by Product

$$\text{Fuel}_i = \text{Total Fuel}_{\text{Cogen}} \times [(\text{Heat}_{\text{CCS Project}} + \text{Electricity}_{\text{CCS Project}}) / (\text{Heat}_{\text{Cogen}} + \text{Electricity}_{\text{Cogen}})]$$

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).[32]
Total Fuel $_{\text{Cogen}}$	=	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 $_{\text{CCS Project}}$	=	Quantity of thermal energy purchased from the third party cogeneration unit to operate the CO_2 capture facilities (MWh/year).
Electricity $_{\text{CCS Project}}$	=	Quantity of electricity purchased from the third party cogeneration unit to operate the CO_2 capture and compression facilities (MWh/year).
Heat $_{\text{Cogen}}$	=	Total quantity of thermal energy generated by the third party cogeneration unit (MWh/year).
Electricity $_{\text{Cogen}}$	=	Total quantity of electricity generated by the third party cogeneration unit (MWh/year).

4.2.2 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 also applies to CO_2 transported in containers (e.g., by barge, rail or truck).

For pipeline transport, the emissions quantification procedures in this section apply to a CCS project that includes a dedicated pipeline moving CO_2 from the capture site to the storage site. For CO_2 transport using a network of pipelines, where project CO_2 can be commingled with CO_2 from other sources (e.g. in West Texas), different quantification procedures using system-wide emission factors can be used as outlined in Section 4.2.3.

GHG emissions from CO_2 transport by pipeline 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. For transport of

[32] 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

CO_2 in containers, mobile sources (barge, rail, or truck) are the main source of GHG emissions. There may be venting and fugitive emissions depending on the nature of equipment used to transport the CO_2 containers. These emissions shall also be calculated and accounted for under project emissions from the transport segment. Table 5-3 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 4.8: Total Project Emissions from the Transport Segment

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

Where,

$PE_{Transport,\,y}$	=	Project emissions from CO_2 transport in year y (tCO_{2e}/yr).
$PE_{T\text{-}Comb,\,y}$	=	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 4.9. This term does not apply to CO_2 transport by barge, rail, or truck.
$PE_{T\text{-}VF,\,y}$	=	Project emissions from venting events and fugitive releases from the CO_2 pipeline or from the CO_2 containers during transport and associated equipment in each year (tCO_2e/yr). Refer to Equation 4.10.
$PE_{T\text{-}Electricity,\,y}$	=	Project emissions from electricity consumed to operate the CO_2 pipeline and associated equipment in each year (tCO_2e/yr). Refer to Equation 4.11. This term does not apply to CO_2 transport by barge, rail, or truck.
$PE_{T\text{-}Mobile,\,y}$	=	Project emissions from each mode of transport (barge, rail, or truck) used to transport the CO_2 containers from capture site to the storage site in each year (tCO_2e/yr). Refer to Equation 4.12. This term does not apply to CO_2 transport by pipeline.

A variety of stationary combustion equipment is used to maintain and operate the CO_2 pipeline. Stationary combustion equipment that is 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 for CO_2 transport are quantified according to the following equation.

Equation 4.9: CO_2, CH_4, N_2O Emissions from Stationary Combustion for CO_2 Transport[33]

$$PE_{T\text{-}Comb,\,y} = \sum(Fuel_i \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times CH_4\text{-}GWP + \sum(Fuel_i \times EF\ N_2O_{Fuel\ i}) \times N_2O\text{-}GWP$$

Where,

$PE_{T\text{-}Comb,\,y}$	=	Project emissions from combustion of fossil fuels in stationary equipment to maintain and operate the CO_2 pipeline infrastructure in each year (tCO_2e/yr).
$Fuel_i$	=	Volume or mass of each type of fuel, by fuel type i, used 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).
CH_4-GWP	=	Global Warming Potential of CH_4.
N_2O-GWP	=	Global Warming Potential of N_2O.

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.

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

[33] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

Equation 4.10: 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 4.10a.
$CO_2\ Supplied_{Storage,\,y}$	=	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 4.10b.

Equation 4.10a: 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 or container, 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 or container, metered at the point of transfer with the capture site in each year at standard conditions ($m^3\ CO_2/yr$).
$\%CO_2$	=	% 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 = 0.00190 metric ton/m^3.

Equation 4.10b: CO_2 Transferred from CO_2 Pipeline to CO_2 Storage Site

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

Where,

$\mathbf{CO_2\ Supplied}_{Storage,\ y}$	=	CO_2 supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO_2/yr).
$\mathbf{Vol.}_{Gas\ Supplied,\ y}$	=	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 at standard conditions ($m^3\ CO_2/yr$).
$\mathbf{\%CO_2}$	=	% CO_2 in the gas stream measured at the transfer with the storage site (% volume).[34]
$\mathbf{\rho CO_2}$	=	Density of CO_2 at standard conditions = 0.00190 metric ton/ m^3.

A mass balance method is not appropriate in situations where the uncertainty of the measured values is greater than the magnitude of the quantified emissions.[35] In those cases, vented and fugitive emissions shall 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.

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. The indirect emissions associated with purchased electricity for CO_2 transport can be quantified according to the following equation.

[34] Composition of gas delivered to storage site is assumed to be same composition as the gas at inlet to the pipeline or received by container.

[35] This can be done by performing an uncertainty analysis for Eq. 4.10 and comparing the result with the difference between $\mathbf{CO_2\ Received}_{Capture,\ y}$ **and -** $\mathbf{CO_2\ Supplied}_{Storage,\ y}$.

Equation 4.11: CO_2e Emissions from Electricity Consumption for CO_2 Transport

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

Where,

$PE_{T\text{-}Elec,\,y}$	=	Project emissions from electricity usage from equipment used to operate the CO_2 pipeline transport infrastructure in each year (tCO_2e/yr).
Electricity	=	Total metered electricity usage from equipment used to operate the CO_2 pipeline transport infrastructure in each year (MWh).
$EF_{Electricity}$	=	Emission factor for electricity generation in the relevant region, by (in order of preference) PCA, eGRID subregion, or State (tCO_2e/MWh). See Section 4.2.1 for estimation procedures.

Mobile source emissions for CO_2 transport by barge, rail, or truck modes are calculated by aggregating the ton-miles transported by each mode and multiplying the individual totals by an appropriate mode-specific emission factor. Total CO_2e emissions are calculated from the following equation:

Equation 4.12: CO_2e Emissions from Mobile Transport of CO_2 Containers[36]

$$PE_{T\text{-}Mobile,\,y} = \sum(Ton\text{-}miles_i \times EF\ CO_{2\ i} \times 10^{-3}) + \sum(Ton\text{-}miles_i \times EF\ CH_{4\ i} \times 10^{-6}) \times CH_4\text{-}GWP + \sum(Ton\text{-}miles_i \times EF\ N_2O_{\ i} \times 10^{-6}) \times N_2O\text{-}GWP$$

Where,

$PE_{T\text{-}Mobile,\,y}$	=	Total emissions from all modes of transport (barge, rail, or truck) that were used to transport the CO_2 containers from capture site to the storage site in each year (tCO_2e/yr).
$Ton\text{-}miles_i$	=	Ton-miles for each mode of transport, by mode type i, used to transport the CO_2 containers in each year. Note: the ton-miles calculation includes the weight of the container plus the weight of the contained CO_2 (ton-miles/yr).
$EF\ CO_{2\ i}$	=	CO_2 emission factor for mode i (barge, rail, or truck), (kg/ton-mile).
$EF\ CH_{4\ i}$	=	CH_4 emission factor for mode i (barge, rail, or truck), (g/ton-mile).
$EF\ N_2O_{\ i}$	=	N_2O emission factor for mode i (barge, rail, or truck), (g/ton-mile).
$CH_4\text{-}GWP$	=	Global Warming Potential of CH_4.
$N_2O\text{-}GWP$	=	Global Warming Potential of N_2O.

[36] Emission factors for CO_2, CH_4, and N_2O emissions for product transport are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

4.2.3 Calculating CO_2 Transport Emissions According to System-Wide Emission Factors

The emissions quantification procedure for the CO_2 pipeline 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 one or more 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 is appropriate. The project proponent shall 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.[37] For completeness, a comprehensive loss factor shall also incorporate vented and stationary combustion emission sources within the appropriate GHG assessment boundary, and emissions from purchased electricity.

4.2.4 Calculation Procedures for CO_2 Storage

The emissions calculation procedures for CO_2 storage cover direct CO_2, CH_4, and N_2O emissions from stationary combustion; CO_2 and CH_4 emissions from venting and fugitive releases to the atmosphere; and indirect CO_2e emissions from purchased electricity use. The procedures also account for any CO_2 that is produced with the hydrocarbons and transferred offsite (i.e., the CO_2 is not re-injected into a reservoir that is within the project boundary) and leakage of injected CO_2 from the reservoir to the atmosphere. 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.

The emissions quantification methodology for CO_2 storage includes all emissions sources located between the point of transfer from 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 EOR 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

[37] 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.

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 and is addressed in Section 4.2.5.

The methodology does not treat CO_2 produced from wells at EOR sites that is recycled and re-injected into the storage formation as an emission, provided the CO_2 remains within the closed loop system and is 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 4.16. Intentionally vented CO_2 in the recycle system (for operational purposes) is treated as a vented emission and accounted for in Equation 4.15.

The following equation outlines the methods for calculating emissions from CO_2 storage. Table 5-3 provides monitoring parameters for calculating emissions from CO_2 storage.

Equation 4.13: Total Project Emissions from CO_2 Storage

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

Where,

$PE_{Storage\text{-}P,\,y}$	=	Project emissions from CO_2 injection and storage in each year (tCO_2e/yr).
$PE_{S\text{-}P\text{-}Comb,\,y}$	=	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 4.14.
$PE_{S\text{-}P\text{-}Vent,\,y}$	=	Project emissions from venting of CO_2 at the injection wells or other surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells in the 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 4.15.
$PE_{S\text{-}P\text{-}Fug,\,y}$	=	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 from 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 offsite in each year (tCO_2e/yr). Refer to Equation 4.16.
$PE_{S\text{-}P\text{-}Elec,\,y}$	=	Project emissions from consumption of electricity used to operate equipment at the producing formation at the storage site in each year (tCO_2e/yr). Refer to Equation 4.17.
$PE_{S\text{-}P\text{-}CO2\,Transfer}$	=	Produced CO_2 from an enhanced oil or gas recovery operation transferred offsite in each year (tCO_2/yr). Refer to Equation 4.18.
$PE_{S\text{-}P\text{-}Leakage,\,y}$	=	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 4.2.5.

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 EOR 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. [38]

Equation 4.14: CO_2, CH_4, N_2O Emissions from Stationary Combustion and Flaring for CO_2 Storage[39]

$$PE_{S\text{-}P\text{-}Comb,\,y} = \sum(Fuel_i \times EF\ CO_{2\ Fuel\ i}) + \sum(Fuel_i \times EF\ CH_{4\ Fuel\ i}) \times CH_4\text{-}GWP + \sum(Fuel_i \times EF\ N_2O_{Fuel\ i}) \times N_2O\text{-}GWP + PE_{Flaring,\,y}$$

Where,

$PE_{S\text{-}P\text{-}Comb,\,y}$	=	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 EOR-associated hydrocarbon production facilities in each year (tCO_2e/yr).
$Fuel_i$,	=	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).
CH_4-GWP	=	Global Warming Potential of CH_4.
N_2O-GWP	=	Global Warming Potential of N_2O.
$PE_{Flaring,\,y}$	=	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. See Equation B-6 (Appendix B).

[38] Appendix B provides a procedure for calculating emissions from combusting hydrocarbons produced at the formation (e.g., in flares).

[39] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

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 shall 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 4.15: Vented CO_2e Emissions from CO_2 Storage

$$\mathbf{PE}_{\text{S-P -Vent, y}} = \sum_{j=1}^{2}\sum_{i=1}^{I} \mathbf{N}_{\text{Blowdown i}} \times \mathbf{V}_{\text{Blowdown i}} \times \%\mathbf{GHG}_{\text{j}} \times \boldsymbol{\rho}_{\text{GHGj}} \times \mathbf{GWP}_{\text{j}} \times \mathbf{0.001}$$

Where,

$\mathbf{PE}_{\text{S-P-Vent, y}}$	=	Project emissions from vented CO_2 at the injection wells or other surface facilities located between the point of transfer from 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).
$\mathbf{N}_{\text{Blowdown i}}$	=	Number of blowdowns for equipment i in each year, obtained from blowdown event logs retained by storage site operator.
$\mathbf{V}_{\text{Blowdown i}}$	=	Total volume of blowdown equipment chambers for equipment i (including pipelines, manifolds and vessels between isolation valves) (m^3, ft^3). For well releases use measured or estimated gas volumes released using procedures in USEPA subpart W[40].
$\%\mathbf{GHG}_{\text{j}}$	=	Concentration of GHG 'j' in the injected gas in year y (volume percent GHG, expressed as a decimal fraction). j=1 for CO_2 and j=2 for CH_4.
$\boldsymbol{\rho}_{\text{GHG j}}$	=	Density of relevant GHG (CO_2 or CH_4) at conditions in the blowdown chamber, kg/m^3 or kg/ft^3. At standard conditions $\rho_{CO2} = 0.0538$ kg/ft^3 and $\rho_{CH4} = 0.0196$ kg/ft^3).[41]
$\mathbf{GWP}_{\text{j}}$	=	100 year Global Warming Potential of relevant GHG
$\mathbf{0.001}$	=	Conversion factor to convert from kg to metric tons.

Fugitive emissions of CO_2, and in some cases CH_4, 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 occur 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

[40] US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010; and subsequent amendments available at http://www.epa.gov/ghgreporting/reporters/subpart/w-regdocs.html

[41] 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.

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. Since produced water is often injected back into the producing formation as part of the EOR process, those volumes are not included in this fugitive emissions calculation. Project Proponents shall only include fluids leaving the project boundary.

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

Equation 4.16: Fugitive CO_2e Emissions from Wells and Surface Equipment

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

Where,

$PE_{S\text{-}P\text{-}Fugitive,\ y}$	=	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 from 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).
$PE_{S\text{-}P\text{-}Fug\text{-}Equipment,\ y}$	=	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 from 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 4.16a.
$PE_{S\text{-}P\text{-}Fug\text{-}Entrained\ CO2,\ y}$	=	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 4.16b.

Equation 4.16a: CO_2 & CH_4 Fugitive Emissions from Equipment Leaks

$$\mathbf{PE}_{\text{S-P -Fug-Equipment, y}} = \sum_{j=1}^{2}\sum_{s=1}^{S} \mathbf{Count_s} \times \mathbf{EF_s} \times \mathbf{T_s} \times \%\mathbf{GHG}_j \times \boldsymbol{\rho}_{\mathbf{GHGj}} \times \mathbf{GWP_j} \times \mathbf{0.001}$$

Where,

$\mathbf{PE}_{\text{S-P -Fug-Equipment, y}}$	=	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 from 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).
$\mathbf{Count_s}$	=	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer from 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.
$\mathbf{EF_s}$	=	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).
$\mathbf{T_s}$	=	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.
$\%\mathbf{GHG}_j$	=	Concentration of GHG 'j' (CO_2 or CH_4) in the injected or produced gas (Volume fraction CO_2 or CH_4). j=1 for CO_2 and j=2 for CH_4.
$\boldsymbol{\rho}_{\mathbf{GHGj}}$	=	Density of relevant GHG (CO_2 or CH_4) at standard conditions in kg/m^3 or kg/ft^3. At standard conditions ρ_{CO2} = 0.0538 kg/ft^3 and ρ_{CH4} = 0.0196 kg/ft^3).
$\mathbf{GWP_j}$	=	100 year Global Warming Potential of relevant GHG
$\mathbf{0.001}$	=	Conversion factor to convert from kg to metric tons.

Equation 4.16b: CO_2 Fugitive Emissions Entrained in Produced Hydrocarbons

$PE_{S\text{-}P\text{-}Fug\text{-}Entrained\ CO2,\ y}$ =	$(Vol._{Gas\ Sold} \times \%\ CO_{2\ Gas\ Sold} \times \rho\ CO_2 \times 0.001) +$ $(Mass_{Water\ Prod} \times Mass\ Frac_{CO2\ in\ Water}) +$ $(Mass_{Oil\ Prod} \times Mass\ Frac_{CO2\ in\ Oil})$	
Where,		
$PE_{S\text{-}P\text{-}Fug\text{-}Entrained\ CO2,y}$	=	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 (tCO_2/yr).
$Vol._{Gas\ Sold}$	=	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/yr, measured at standard conditions).
$\%\ CO_{2\ Gas\ Sold}$	=	% 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 (% volume).
$\rho\ CO_2$	=	Density of CO_2 at standard conditions (= 1.899 kg /m^3).
0.001	=	Conversion factor to convert from kg to metric tons.
$Mass_{Water\ Prod}$	=	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).
$Mass\ Frac_{CO2\ in\ Water}$	=	Mass fraction of CO_2 in the water produced from the formation.
$Mass_{Oil\ Prod}$	=	Mass of crude oil and other hydrocarbons produced from the formation that CO_2 is being injected into (metric tons/year).
$Mass\ Frac_{CO2\ in\ Oil}$	=	Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation.

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 EOR 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.

Indirect GHG emissions from purchased electricity used to operate equipment at the EOR operations are quantified according to the following equation.

Equation 4.17: CO_2e Emissions from Purchased Electricity Consumption for CO_2 Storage

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

Where,

$PE_{S\text{-}P\text{-}Elec,\,y}$	=	Project emissions from electricity used to operate equipment at the CO_2 storage site in each year (tCO_2e/yr).
Electricity	=	Total metered electricity usage from equipment used to operate the storage site and the hydrocarbon production facilities in year y (MWh).
$EF_{Electricity}$	=	Emission factor for electricity generation in the relevant region, by (in order of preference) PCA, eGRID subregion, or State (tCO_2e/MWh). See Section 4.2.1 for estimation procedures

A Project Proponent could move produced-CO_2 between EOR 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). In some instances, however, CO_2 can be transferred out of the project boundary. While this CO_2 is not necessarily an emission to the atmosphere, Project Proponents shall nevertheless account for it as an emission rather than treating it as if it were sequestered from the atmosphere.

Equation 4.18 presents the approach to calculate emissions from CO_2 transferred outside the project boundary. Note: Project Proponents shall not include any CO_2 volumes that were sold to third parties and already accounted for under Equation 4.16b.

Equation 4.18: CO_2 Transferred Outside Project Boundaries

$$PE_{S\text{-}P\text{-}CO2_Transfer} = Vol_{CO2_Transfer} \times \rho CO_2 \times 0.001$$

Where,

$PE_{S\text{-}P\text{-}CO2\ Transfer}$	=	Produced CO_2 from an EOR operation transferred outside project boundary in each year (tCO_2/yr).
$Vol_{CO2_Transfer}$	=	Volume of produced CO_2 from an enhanced oil or gas operation transferred outside project boundary in each year under standard conditions (m^3, ft^3).
ρCO_2	=	Density of CO_2 at standard conditions (1.899 kg/m^3 or 0.0538 kg/ft^3).
0.001	=	Conversion factor to convert from kg to metric tons.

4.2.5 Accounting for Atmospheric Leakage of CO_2 from the Storage Volume

Any injected CO_2 that is not produced with the oil remains contained in the oil reservoir because of the confining layer above the oil reservoir that traps it in place. This is the same confining layer that formed an effective seal and contained the oil and gas in the reservoir for millions of years and now serves to trap the CO_2. However, Project Proponents must quantify atmospheric leakage of CO_2 emissions from the storage volume, if they arise. Atmospheric leakage shall be monitored during the entire Project Term, which includes the injection period and a time-period following the end of injection as defined in Section 2.2. Methods to assure the long-term storage of CO_2 beyond the Project Term will be required; these and associated reversal risk mitigation measures are outlined in Section 5.4

The following general equation to account for atmospheric leakage from the CO_2 storage volume 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.

In this methodology, the details of detecting and estimating atmospheric leakage are discussed in Section 5.4. If atmospheric leakage is detected during injection operations, it must be quantified and deducted as project emissions in the year the leakage was detected using equation 4.19. If the estimated atmospheric leakage is large and exceeds the ERs calculated for that year (See Section 4.3 for calculation of ERs), it can be mitigated by options discussed in Section 6.3 (Table 6-1).

Equation 4.19: Atmospheric Leakage of CO_2 Emissions from CO_2 Storage Volume During the Injection Period[42]

$$\mathbf{CO_{2_{Atm.\ Leakage-INJ,y}}} = \sum_{z=1}^{Z} \mathbf{CO_{2_{z,y}}}$$

Where,

$CO_{2_{Atm.\ Leakage-INJ}}$	=	Total mass of CO_2 emitted to the atmosphere through subsurface leakage from the formation in year y during the injection period (metric tons).
CO_{2_z}	=	Total mass of CO_2 emitted through leakage pathway z in year y (metric tons).
z	=	Leakage pathway.

Equation 4.20, which is similar to Eq. 4.19, is used to report atmospheric leakage that occurs after the injection period. Mitigation of post-injection leakage is discussed in Section 6.3.

Equation 4.20: Atmospheric Leakage of CO_2 Emissions from CO_2 Storage Volume After the Injection Period

$$\mathbf{CO_{2_{Atm.\ Leakage-PI}}} = \sum_{z=1}^{Z} \mathbf{CO_{2_z}}$$

Where,

$CO_{2_{Atm.\ Leakage-PI}}$	=	Total mass of CO_2 emitted to the atmosphere through subsurface leakage from the formation after the injection period (metric tons).
CO_{2_z}	=	Total mass of CO_2 emitted through leakage pathway z (metric tons).
z	=	Leakage pathway.

4.3 Emission Reductions

As shown in Equation 4.21, overall GHG emission reductions (ERs) from the CCS project equal Baseline Emissions minus Project Emissions.

[42] 40 CFR §98.443(e), Eq. RR-10, 40

Equation 4.21: Total Annual GHG Reductions

$$\mathbf{GHG\ ER_y = BE_y - PE_y}$$

Where,

$GHG\ ER_y$	=	Total annual GHG reductions from the CCS project (tCO_2e/yr).
BE_y	=	Baseline CO_2e emissions in each year (from eq. 4.1 or 4.2, tCO_2e/yr).
PE_y	=	Project CO_2e emissions in each year (from eq. 4.3, tCO_2e/yr).

5.0 DATA COLLECTION AND MONITORING

5.1 Reporting Period

The reporting period can be defined at the discretion of the Project Proponent, provided it conforms to ACR's guidelines on reporting periods. The *ACR Standard* requires a field visit by the verifier at minimum every 5 years. In between field visits, verification may be via a desktop assessment, which may be annual or at any other interval at the Project Proponent's discretion, but verification is required prior to any issuance of offset credits.

5.2 Baseline Emissions Measurement

Baseline emission measurement parameters and considerations are summarized in Table 5-1 for the Projection-based and Standards-based calculation procedures. Details of the calculation procedures are included in Section 4.0.

Table 5-1 Overview of Baseline Emissions 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 4.1.2 Equation 4.1** 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 used to calculate baseline emissions may need to be adjusted to account for the incremental CO_2 generated to meet the energy requirements of the capture process. This could occur if the energy required to operate the CO_2 capture process equipment is provided by electricity or thermal energy generated from the same process producing 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 calculating 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. Further, any additional CO_2 emissions that could result from poor or negligent operation of the primary process, or from not meeting regulations, which are included in the baseline shall be deducted as excess CO_2 emissions. Determine excess CO_2 emissions from violations to facility permit conditions and deduct from baseline as indicated in Equation 4.1.	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 4.1.3 Equation 4.2** The Standards-based baseline is calculated by multiplying 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). The emissions intensity metric may be a region-specific or CCS project-type specific standard that is set by Federal, State, or Local Regulatory Agencies. Procedures for collecting data from the actual project to determine the output value used to calculate baseline emissions shall 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 shall be measured to account for the total output from the primary process that would have occurred in the absence of the project.

5.3 Project Emissions Measurements

Project emission sources and GHG measurement parameters are summarized in Table 5-2. Details of the calculation procedures are included in Section 4.0. In addition to measurement parameters shown in Table 5-2, a detailed monitoring, reporting, and verification (MRV) plan must be developed for each geologic storage site used in the CCS project. The MRV plan is discussed in Section 5.4.

Table 5-2 Overview of Project Emissions Calculation Procedures

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
CO_2 Capture		
Total Capture Emissions CO_2; CH_4; N_2O	**Section 4.2.1, Equation 4.4.** 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 4.2.1, Equations 4.5, 4.5a, 4.5b, 4.5c.** 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 includes 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 4.2.1, Equation 4.5b, 4.6, 4.7b** 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. 3) cogeneration units operated by third parties supplying process energy (e.g, steam, electricity) that are used by the project.	Annual amount of fossil fuel burned, by fuel type

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Electricity and Thermal Energy Use CO_2; CH_4; N_2O	**Section 4.2.1, Equation 4.7, 4.7a, 4.7b, 4.7c.** Indirect 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
CO_2 Transport		
Total Transport Emissions CO_2; CH_4; N_2O	**Section 4.2.2, Equation 4.8.** Total Project Emissions from CO_2 transport, including vented, fugitive, stationary combustion, and purchased and consumed electricity and mobile sources.	N/A
Stationary Combustion CO_2; CH_4; N_2O	**Section 4.2.2, Equation 4.9.** 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 4.2.2, Equations 4.10, 4.10a, 4.10b.** 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. As discussed in Section 4.2.2 in certain situations, emissions shall be calculated according to an event-based approach for vented emissions and a component-count method for fugitive emissions. See "Vented CO_2" & "Fugitive CO_2" sources under "CO_2 Storage".	Metered quantities of CO_2 input into the pipeline or container (if transported by barge, rail, or truck) and delivered to storage site

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Electricity Use (if required) CO_2; CH_4; N_2O	**Section 4.2.2, Equation 4.11.** 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
Mobile Sources (for transport by barge, rail, or truck) CO_2; CH_4; N_2O	**Section 4.2.2, Equation 4.12** Emissions associated with the mode of transport (barge, rail, or truck) used to transport CO_2 containers from the capture to storage site. Multiple modes of transport may be used and the emissions associated with each mode shall be calculated separately and aggregated.	Records of CO_2 container weights and mileage for each trip by each transport mode.
CO_2 Storage		
Total Storage Emissions – CO_2; CH_4; N_2O	**Section 4.2.4, Equation 4.13** Total Project Emissions from CO_2 storage including stationary combustion, vented, fugitive, and electricity consumption emissions.	N/A
Stationary Combustion CO_2; CH_4; N_2O	**Section 4.2.4, Equation 4.14.** Emissions from fossil fuel combustion to operate equipment used to store CO_2 in the oil and gas reservoir. 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

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Vented CO_2; CH_4	**Section 4.2.4, Equation 4.15** 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.
Fugitive CO_2; CH_4 (excluding atmosphere leakage from the storage volume)	**Section 4.2.4, Equations 4.16, 4.16a, 4.16b.** 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

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Electricity Use CO_2; CH_4; N_2O	**Section 4.2.4, Equation 4.17.** Indirect emissions from electricity use at the CO_2 storage site. 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
Transferred CO_2 CO_2	**Section 4.2.4, Equation 4.18.** While not technically an emission, CO_2 transferred outside the project boundary (i.e., produced CO_2 from an EOR operation not re-injected but moved offsite) is deducted from claimed emissions reductions. If an EOR site operator intends to move produced-CO_2 between fields, then the boundary would encompass 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 EOR operation transferred outside project boundary
Atmospheric leakage of CO_2 from the storage volume CO_2	**Section 4.2.5, Equations 4.19 and 4.20.** For properly selected, operated, and closed CO_2 storage operations, atmospheric leakage of CO_2 emissions from the geologic reservoir will not normally occur. Should it occur then emissions shall be calculated on a site-by-site basis as described in Section 5.4. For CO_2 storage, the project-specific MRV 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

5.4 Monitoring, Reporting, and Verification (MRV) Plan

The IOGCC's Task Force on Carbon Capture and Geologic Storage concluded that monitoring and verification of CCS projects would be accomplished best in the subsurface, given the uncertainties and changing technologies of surface monitoring techniques.[43] The Task Force has recommended that the operator submit a comprehensive monitoring plan that is tailored to the specific characteristics of the site. Similar recommendations were made by the USDOE, which indicated that MRV programs need to be flexible and site-specific to adapt to the inherent variability and heterogeneity of geologic systems. MRV plans also change in scope as a project progresses from the pre-injection phase to the post-injection phase. For all these reasons, MRV plans need to be tailored to site-specific geologic conditions and operational considerations.[44]

5.4.1 MRV Plan Framework

A MRV framework for CCS projects shall include the following components:

- Determination of the storage volume that is expected to contain the injected CO_2 during and after the injection period, determined through modeling and flow simulations.
- Identification of potential leakage pathways within this storage volume (usually well bores, faults, and fractures). This information can also feed into the flow simulation model as a potential source of uncertainty.
- Remediation of potential leakage pathways, as needed. This can help reduce the probability of leakage and reduce uncertainty in detecting atmospheric leakage.
- Development of a monitoring strategy to demonstrate effective retention of anthropogenic CO_2 during injection and post-injection periods and for detection of the potential for atmospheric leakage.
- A strategy for quantifying any atmospheric leakage of CO_2.
- A plan for monitoring the parameters included in Table 5-3.

5.4.1.1 Determination of Storage Volume

The storage volume is the rock volume planned to contain the injected CO_2, which includes a vertical and lateral boundary. The vertical boundary shall be set at the top of the confining zone. The lateral boundary shall be set initially at the expected lateral extent of the plume. The lateral extent is

[43] Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces, The Interstate Oil and Gas Compact Commission, September 2007

[44] Best Practices for Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update, DOE/NETL-2012/1568, October 2012

determined through flow simulations of the injection conducted to a point in time when the CO_2 plume ceases to migrate after injection is stopped. The simulation shall account for uncertainties in modeled parameters and potential leakage pathways that could lead to leakage. It may be necessary to redefine the lateral boundary during operations, if the actual injection process differs from the modeled scenarios or other changes are detected that affect the extent of the lateral boundary. An additional buffer region shall be included to account for these uncertainties and for conservativeness. Both vertical and lateral boundaries shall encompass the limits of acceptable CO_2 migration.

5.4.1.2 Identification and Remediation of Potential Atmospheric Leakage Pathways

Potential leakage pathways shall be determined through a detailed site characterization. Examples of conduits for CO_2 leaks to the atmosphere include CO_2 injection wells, oil or gas production wells, monitoring wells, abandoned wells; and faults and fractures. While for properly selected, operated, and closed CO_2 storage operations, CO_2 emissions from the geologic reservoir to the atmosphere should not occur, assessing for potential leakage pathways is an important part of a monitoring program.

Site characterization includes the development of a complete catalogue of existing wells penetrating the injection zone or in the near vicinity of the reservoir, including information on the current well status, data on how the well was completed (and plugged/ abandoned if appropriate) including any cement bond logs available. Assurance as to the adequacy of the plugging of abandoned wells is essential.

A corrective action plan shall be developed for those wells that are considered to be high risk for leakage (i.e., poor condition of cement, poor maintenance, and penetrating the oil reservoir and confining zones). The corrective action plan may involve either remediation or monitoring for leakage at the well.

Good well construction and completion are important to prevent leakage. All CO_2 injection wells used for EOR operations in the US meet Class II well requirements outlined by the USEPA underground injection control (UIC) program.[45] There may be additional State requirements that affect the construction, completion, operation, and testing of Class II wells. Operators shall comply with all applicable State rules affecting Class II wells. As an example, standards and procedures for Class II well operation in the State of Texas are discussed in Appendix C.

[45] USEPA, 40CFR Part 146, Underground Injection Control Program: Criteria and Standards

5.4.1.3 Monitoring Strategy

The monitoring strategy shall be geared to demonstrate effective retention of the injected anthropogenic CO_2 within the storage volume during and after injection. Based on site evaluation and geological parameters in the storage volume, simulations of potential failure scenarios that include a range of uncertainty in modeled parameters and site characteristics shall be developed. Based on the sensitivities of individual parameters to the outcomes of those simulations, the Project Proponent shall determine the specific monitoring parameters to be monitored, the monitoring tools to be used, and the sampling frequency.

A fluid flow model is an essential component of the monitoring strategy. Working with the EOR operator, required data (existing and newly collected) shall be compiled to develop a fluid flow model that is calibrated with production history and used to predict CO_2 distribution during the injection and post-injection phases of the EOR project. To update and compare the model results, material balances for total field CO_2 injection, resulting from purchased CO_2 and recycled CO_2 (CO_2 recovered from oil production and re-injected into the reservoir), as well as any water injected, shall be maintained. The observed material balances for fluids (oil, gas, water, CO_2) shall be compared to the fluid production predicted by the model.

If EOR operators are already required to perform certain test procedures as part of meeting regulatory requirements, then those procedures shall be incorporated into the project's MRV. For example many State regulators require periodic Mechanical Integrity Tests (MITs) to assure well integrity. These activities can help in the early detection of CO_2 leakage out of the injection zone and allow for remedial actions to be taken in a timely manner, thereby reducing the probability of atmospheric leakage from well bores.

Monitoring shall be designed so that it is sensitive to the leakage signal. Project Proponents shall select and locate monitoring equipment and 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 CO_2 storage. The data collected shall test the correctness of key modeling assumptions. The Project Proponent shall identify key project-specific parameters that are indicative of leakage and determine appropriate ranges for those parameters, such that exceedances are indicative of leakage.

Depending on site-specific conditions, the Project Proponent shall determine whether the monitoring approach would benefit from establishing pre-injection levels. If deemed beneficial, these measurements shall be done for a period of time that allows for the collection of data that are

representative of site conditions prior to the initiation of injection. On-going research on pre-injection monitoring techniques and approaches can be used as a valuable resource to develop a project-specific monitoring plan. Innovative strategies to determine sources of groundwater contamination in the absence of pre-injection data, which include the use of stable carbon isotopic signatures, noble gases, and other metrics like hydrogen carbonate can be adopted for brownfield sites.[46] The results of on-going research on soil monitoring can provide data to determine its value in a pre-injection monitoring approach.[47]

5.4.1.4 Post Injection Monitoring

Following completion of CO_2 injection, monitoring shall be maintained during the post-injection phase until the end of the Project Term to assure no atmospheric leakage. The absence of atmospheric leakage during the Project Term is considered assured when it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO_2 will remain contained within the storage volume. Specific monitoring tools shall be determined based on the site-specific experience gained during the pre-injection and operational phases of the project. With the cessation of injection and in the absence of any other changes to reservoir conditions, the pressures within the reservoir should equilibrate and the movement of CO_2 within the reservoir should stabilize. Therefore minimal lateral movement is expected and tracking of the lateral extent of the CO_2 plume through appropriate measurements (such as pressure) and modeling will be adequate. Due to buoyancy effects, the CO_2 plume will tend to migrate to the upper regions of the reservoir where it will be constrained by the caprock. Therefore changes in these subsurface measurements made above the confining zone may be indicative of potential leakage.

The minimum post-injection monitoring period for CCS projects is five (5) years. During this period, subsurface pressure shall be recorded and changes in pressure measurements evaluated, to determine if they are consistent with expected changes or are indicative of leakage. Other monitoring tools shall be implemented in accordance with the site's monitoring plan to assure no leakage. Although atmospheric leakage has not necessarily occurred if the CO_2 migrates to regions outside the storage volume boundaries, it cannot be verified that no leakage has occurred and additional steps are necessary in this case. Project Proponents shall redefine the boundaries of the storage volume. For example, if there is evidence of lateral movement outside the boundaries of the storage volume, then the lateral boundaries shall be extended to regions beyond the original storage volume. However, Project Proponents shall evaluate for the possibility of any new potential atmospheric leakage pathways and

[46] http://184.106.226.121/uploads/File/PDFs/Kerr%20Report%20all%20sections-revised%20May%2023-PDF.pdf
[47] http://www.beg.utexas.edu/gccc/forum/codexhome.php

either remediate them and/or modify the monitoring strategy to detect for leakage under new failure scenarios. The duration of post-injection monitoring shall be extended beyond 5 years if no leakage cannot be assured at the end of the 5-year period. In this case, the Project Term will be extended in two-year increments and monitoring shall be continued until no leakage is assured.

5.4.1.5 Post-Project Term requirements for storage of CO2

The Project Proponent shall file and, if the Project Proponent is not the owner of the pore space comprising and/or surface interests overlying the CO_2 storage volume, cause to be filed by the owners thereof, a Risk Mitigation Covenant in the real property records of each county, parish and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located. The Risk Mitigation Covenant shall apply to any activity occurring on or under the land, shall run with the land (including both the surface and subsurface interests) and shall be in a form approved by ACR. Further, the Risk Mitigation Covenant shall prohibit any planned activity that results in the release of the stored CO_2 including as a collateral effect of future hydrocarbon development (i.e., a reversal) unless measures are taken in advance to compensate for the reversal by replacing the reversed offset credits for ACR's retirement pursuant to a plan acceptable to ACR.

To verify compliance with the terms of the Risk Mitigation Covenant, the Risk Mitigation Covenant shall require that the Project Proponent and the owner of the property notify ACR upon discovery of the occurrence of or plans to conduct any activity that results in a reversal, shall require that the Project Proponent and owner of the property submit an annual attestation of compliance to ACR, and shall afford ACR an access right to the property in order to conduct inspections. The obligations under the Risk Mitigation Covenant shall be secured by a lien in favor of ACR against the CO_2 and the pore space comprising the CO_2 storage volume, which lien shall be included in the Risk Mitigation Covenant.

In the event that the Project Proponent is not the owner of the pore space comprising and/or surface interests overlying the CO_2 storage volume and is unable to provide the required Risk Mitigation Covenant as part of the demonstration of project eligibility, as an alternative to the Risk Mitigation Covenant ACR may accept (i) proof of the filing of a notice or memorandum of agreement in a form acceptable to ACR in the real property records of each county, parish and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located that provides notice of the following terms of the Project Proponent's agreement with such pore space and/or surface interest right owners to any future owners: (a) the agreement that no planned activity shall be conducted that would result in a reversal unless measures are taken in advance to compensate for the reversal by replacing the reversed offset credits for ACR's retirement pursuant to a plan acceptable to ACR (b) the agreement

to notify ACR upon discovery of the occurrence of a reversal; and (c) a right of access by Project Proponent or its assigns, including ACR, for access to conduct inspections; or (ii) another risk mitigation measure intended to prevent, provide for the discovery of, and compensate for intentional reversals that is acceptable to ACR.

The Risk Mitigation Covenant or alternative risk mitigation assurance shall be approved by ACR and, as applicable, filed in all required jurisdictions, with a copy of the filed documents provided to ACR prior to the issuance of any offset credits for the GHG project other than offset credits subject to Invalidation. If a Project Proponent does not provide a Risk Mitigation Covenant or an alternative risk mitigation assurance as described above, the offset credits issued by ACR for the project shall be subject to Invalidation; provided however, offset credits subject to Invalidation may be exchanged for offset credits that are not subject to Invalidation in the event the Project Proponent provides ACR with a Risk Mitigation Covenant or alternative risk mitigation assurance satisfying the requirements of this Section 5.4.1.

The obligations of the Project Proponent and any pore space or surface owner under the Risk Mitigation Covenant or alternative risk mitigation assurance shall cease upon demonstration to the reasonable satisfaction of ACR, as evidenced by a written acknowledgement by ACR, that the federal government or the applicable state government has assumed ownership of and monitoring responsibility for the stored CO_2 by the Project Proponent. Any pore space or surface owner shall be relieved of intentional reversal mitigation requirements for any intentional reversal occurring after such government assumption. ACR's written acknowledgement shall be in recordable form and may be filed in the applicable real property records by the Project Proponent or any pore space or surface owner to evidence the termination of the Risk Mitigation Covenant or alternative risk mitigation assurance.

5.4.1.6 Quantification of Atmospheric Leakage

The project monitoring plan shall include a strategy for quantifying any atmospheric leakage of CO_2 from the storage volume. In the event that leaks from the storage volume do happen, which are not remediated in time to prevent atmospheric leakage, Project Proponents shall quantify the CO_2 emissions on a site-by-site basis, according to a reasonable engineering approach. This shall involve computations that incorporate a range of information about the specific geologic reservoir, the CO_2 injection regime, modeling assumptions, and other variables. The EOR field operator has the best knowledge of site-specific conditions and shall combine this knowledge with sound engineering practices to estimate atmospheric leakage, should it occur. This includes the use of conservative factors and algorithms in their estimates. Further, the uncertainty in the estimated value shall be calculated and included in the estimates. In the event of containment failure, a simplified estimation to conservatively determine maximum leakage can be used, rather than requiring rigorous quantification.

5.4.2 MRV Plan Reporting Requirements

Besides the normal GHG Project Plan reporting requirements specified by ACR, CCS projects shall also include a site-specific MRV plan, which is subject to independent third party validation by a CCS expert on the VVB team (see below). It shall include:

- Description of the reservoir where CO_2 is injected.
- Description of model, including key model parameters and their uncertainties, potential failure scenarios evaluated, and simulation results to determine the extremities of the storage volume that is expected to contain the injected CO_2 through the end of the Project Term.
- Site characterization of the storage volume, including identification of potential leakage pathways and any remediation activities undertaken to reduce potential for leakage.
- Monitoring strategy, including monitoring procedures and tools, and monitoring frequency. A range of expected values for monitored parameters that indicate normal operation and that containment is successful. Note: there may be changes to monitoring strategy as the injection proceeds. The Project Proponent shall document and report changes and the revisions shall be subject to review by the VVB at the next verification interval or next validation (in the case of Crediting Period renewal), whichever comes first.
- If leakage is detected, remedial actions taken to rectify the source of leakage, and/or estimates of atmospheric leakage and how it was mitigated.

It is required that the project-specific MRV Plan be developed by a professional with demonstrated experience and knowledge of design and implementation of systems for monitoring geologic storage of CO_2, along with expertise in an earth science discipline relevant to monitoring, such as reservoir engineering, geophysics, geology, hydrology, geomechanics, geochemistry, or other relevant discipline. Demonstrated experience/knowledge shall be evidenced by at least three years' experience in monitoring of CO_2-EOR projects, and/or by published, relevant peer-reviewed academic research on monitoring of CO_2 storage. The curriculum vitae of this professional will be reviewed by ACR and the VVB to confirm that he/she meets the above requirements.

5.4.3 MRV Plan Validation and Verification Requirements

Validation of the MRV plan shall be conducted by a competent third party Validation and Verification Body (VVB) with in-house or subcontracted CCS expertise meeting the requirements below. The VVB shall determine the adequacy of the MRV plan to meet the storage goals. It includes verification of the model used; model parameters, assumptions and uncertainties; failure scenarios evaluated; and the adequacy of the monitoring strategy to detect leakage out of the storage volume. The VVB shall also review the EOR operator's injection permit and verify that the site remained in compliance during the reporting year. In instances of non-compliance, the VVB shall determine whether it affects the ERs

claimed and the potential to affect future ERs or compromise long-term storage. The review shall also include a comparison of the MRV Plan with existing protocols and regulations.

The project-specific MRV Plan must be independently validated by a professional with demonstrated experience and a high degree of knowledge of design and implementation of systems for monitoring geologic storage of CO_2, along with expertise in an earth science discipline relevant to monitoring, such as reservoir engineering, geophysics, geology, hydrology, geomechanics, geochemistry, or other relevant discipline. Demonstrated experience/knowledge shall be evidenced by at least three years' experience in monitoring of CO_2-EOR projects, and/or by published, relevant peer-reviewed academic research on monitoring of CO_2 storage.

This professional shall be an independent third party serving as part of the VVB team. He/she may be a subcontractor to the VVB as long as the VVB accepts full responsibility for his/her work through their role as signatory of all validation and verification opinions. He/she shall be subject to the VVB's project-specific Conflict of Interest evaluation.

The project-specific MRV Plan must be approved by this professional at the time of initial validation. Subsequent verifications must also be reviewed by this professional, or a professional meeting the same qualifications, to ensure that the project-specific MRV Plan is being adhered to in every reporting period when credits are claimed. Subsequent validations (on Crediting Period renewal every ten years) shall also include review by this professional, or a professional meeting the same qualifications, of any changes to the MRV Plan.

The validation of the initial MRV Plan and subsequent validations and verifications must also be signed off by a registered Professional Engineer (PE) or geologist, who may be (but is not required to be) the same individual as the professional described above.

5.5 Measurement Techniques

Volumetric flow rates will be measured by commercially available devices that measure the mass or volumetric rate of flow of a gas or liquid moving through an open or closed conduit. Flow meters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flow meters, and vortex flow meters. The devices shall be installed and calibrated in accordance with manufacturer’s specifications. The flow meter will be operated in accordance with an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. The specific standard used shall be documented and reported. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the

American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB). Flow meter calibrations performed shall be National Institute of Standards and Technology (NIST) traceable.

Gas or liquid composition analysis shall be measured by an appropriate standard method published by a consensus-based standards organization, if such a method exists, or an industry standard practice.

Flowrate measurements are made continuously, where continuous measurement is commonly defined as one measurement every 15 minutes or less. The CO_2 concentration in the gas stream is measured at monthly intervals.

Monitoring methods for MRV of geologic storage sites are discussed in USDOE and USEPA documents and are also contained in certain State regulations.[48,49,50,51]

5.6 Data and Analysis for Verification

This section provides information about specific parameters that shall be monitored to calculate GHG emission reductions from a CCS project according to the quantification procedures in Section 4.0. Project Proponents shall incorporate this information into their project-specific MRV Plan 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. Table 5-3 aggregates the specific monitoring parameters and activities needed for a comprehensive assessment of the GHG reductions that might be claimed by a Project Proponent. Project Proponents shall take into account the location, type of equipment and frequency of measurement for each variable.

In addition to the parameters in Table 5-3, project proponents shall report the results of the MRV measurements discussed in Section 5-4.

[48] Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations, DOE/NETL-311/081508, January 2009, www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf

[49] Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update, DOE/NETL-2012/1568, October 2012, http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf

[50] General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU Greenhouse Gas Reporting Program, (Chapter 4 & 5), USEPA, (2010) www.epa.gov/climatechange/emissions/downloads10/Subpart-RR-UU_TSD.pdf

[51] Fluid Injection in Productive Reservoirs, Texas Administrative Code (TAC), Title 16, Part 1, RULE §3.46

The EOR site must remain in compliance with its permit conditions through the injection monitoring period. EOR site operators shall produce documentation indicating that their site has been in regulatory compliance. If there are periods of non-compliance then the date(s) and nature of non-compliance, remedial actions taken, and the date(s) when the site returns to being in compliance shall be documented and provided during verification. If there are periods of non-compliance, then the effect of non-compliance on the quantified emission reductions shall be evaluated and, if necessary the creditable emission reductions shall be reduced.

Table 5-3 Monitoring Parameters[52]

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Projection-Based Baseline					
Vol. $_{\text{Gas Produced}}$	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	[m]	Continuous	Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
%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	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.

[52] Based on A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
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)	[m]	Daily	Measurement based on the type of primary process. Output shall be measured to account for the total output from the primary process that would have occurred in the absence of the project. Measurement devices shall be calibrated in accordance with manufacturer's specifications.
Non-Captured CO_2 Emissions from the Primary Process					
Vol. $_{\text{Gas Produced}}$	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	[m]	Continuous	Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
$\%CO_2$	% 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	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis Gas analyzers shall 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, m^3, scf, metric tons	[m], [o]	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications. For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fossil fuels consumed to operate the CCS systems.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Vol. $_{\text{Gas Transferred}}$	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	[m]	Continuous	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is commonly defined as one measurement every 15 minutes or less.
Stationary Combustion Emissions for CO_2, CH_4, and N_2O					
Fuel i	Volume of each type of fuel, by fuel type i, used to operate each component (capture, transport, and storage) of the CCS project in year y.	m^3, scf, Liter, gallons, metric tons	[m], [o]	Daily, monthly	For gaseous fuels, daily measurement of the gas flow rate. Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications. For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fossil fuels consumed to operate the CCS project.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Indirect CO_2 Emissions from Purchased and Consumed Electricity, Steam, Heat					
Electricity	Metered electricity usage from equipment used to operate electrically driven component (capture, transport, and storage) in the CCS project in year y.	MWh	[m], [o], [c]	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or reconciliation of maximum kW rating for each type of equipment and operating hours. Electricity meters shall be calibrated by an accredited party per manufacturer's specifications. Electricity consumption shall 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. Electricity usage can also be determined from monthly bills received from the utility.
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, m3, scf, metric tons	[m], [o]	Daily, monthly	Daily metering of gaseous fuels or monthly reconciliation of volumes or masses for liquid or solid fuels purchased and in storage.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
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	[m], [o]	Daily or monthly	Daily metering of thermal energy sales/purchases to/for the CCS project using a utility meter. Monthly billing received from the cogen operator showing the quantity and condition of steam can be used to determine steam usage. Steam meters, or similar, shall be calibrated by an accredited party per manufacturer specifications.
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	[m], [o]	Daily or monthly	Daily measurement of electricity sales/purchases to/for the CCS project. Monthly billing from the cogen operator can be used to determine electricity usage. Electricity meters shall be calibrated by an accredited party per manufacturer's specifications.
Heat Cogen	Total quantity of process energy (e.g. process steam) generated by the third party cogeneration unit in year y.	MWh	[m], [o]	Daily or monthly	Daily metering of total process energy generated using a utility meter. Steam meters, or similar, shall be calibrated by an accredited party per manufacturer's specifications. Cogen operator's monthly records can be used as source of data.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Electricity Cogen	Total quantity of electricity generated by the third party cogeneration unit in year y.	MWh	[m], [o]	Daily or monthly	Daily measurement of total electricity sales/purchases. Electricity meters shall be calibrated by an accredited party per manufacturer's specifications. Cogen operator's monthly records can be used as source of data.
Vented and Fugitive CO_2 Emissions from CO_2 Transport – Mass Balance					
Vol. $_{\text{Gas Received}}$	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	[m]	Continuous	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
%CO_2	% CO_2 in the gas stream being transported by pipeline, measured at the input to the pipeline, in year y.	% CO_2 by volume	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Vol. $_{\text{Gas Supplied}}$	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	[m]	Continuous	Continuous measurement of the volume of gas delivered to the CO_2 storage site, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
Vented and Fugitive CO_2 Emissions from CO_2 Storage					
$N_{\text{Blowdown i}}$	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.	#	[o]	NA	Storage site operator shall keep detailed logs of all venting incidents.
$V_{\text{Blowdown i}}$	Total volume of blowdown equipment chambers for equipment (including pipelines, manifolds and vessels between isolation valves).	m^3, scf	[o], [c]	NA	Volume can be estimated based on equipment specifications (pipeline diameters etc.), flow meters, duration of event.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
$\%\mathbf{GHG}_{j}$	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).	%	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
$\mathbf{Count}_{s}$	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells in the formation.	#	[o]	NA	Storage site operator shall develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities at the storage site.
$\mathbf{T}_{s}$	Total time in hours that the equipment associated with the each fugitive emission source was operational.	Hours	[o]	NA	Estimated based on operational records of downtime at the injection wells, storage site and hydrocarbon production facilities.
Vol. $_{\text{Gas Sold}}$	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	[m]	Daily	Continuous metering of sales volumes of natural gas.
% CO_2 $_{\text{Gas Sold}}$	% 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.	%	[m]	Annual	Direct measurement of the composition of the natural gas at the sales meter.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
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	[o]	Monthly	Monthly reconciliation of water disposal records.
Mass Frac $_{\text{CO2 in Water}}$	Mass fraction of CO_2 in the water produced from the formation.	-	[m]	Annual	Conduct lab analysis of composition of produced water. Report dissolved inorganic carbon species.
Mass $_{\text{Oil Prod}}$	Mass of crude oil and other hydrocarbons produced from the formation into which CO_2 is being injected.	Metric tons	[m]	Monthly	Reconciliation of hydrocarbon sales from facilities associated with the producing formation.
Mass Frac $_{\text{CO2 in Oil}}$	Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation.	-	[m]	Annual	Conduct lab analysis of composition of crude oil
CO_2 Transferred Offsite					
Vol $_{\text{CO2_Transfer}}$	Volume of produced CO_2 from an EOR operation transferred outside project boundary in each year.	m^3, scf	[m]	Monthly	Projects Proponent shall 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.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Atmospheric Leakage of CO_2 from Storage					
CO_{2Z}	Total mass of CO_2 emitted through leakage pathway z to atmosphere in year y.	Metric tons	[c]	NA	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: This does not include fugitive CO_2 emissions from wells, which are calculated according to Equation 4.16.

6.0 EMISSIONS OWNERSHIP AND QUALITY

6.1 Statement of Direct Emissions

The Project Proponent shall attest annually that all emission reductions occur on the property owned and/or controlled by the Project Proponents and that none of the emission reductions claimed by the project are indirect emissions.

6.2 Title

Since CCS projects involve capture, transport, and sequestration processes, which are often conducted by different companies, the ownership to the title of CO_2 credits associated with the project's emission reductions must be clearly defined. This can be done through contracts among the parties in which one of the companies has clear ownership of the credits.

During the operational phase, documentation that traces the chain of custody of CO_2 as it is transferred from parties involved in the capture, transport, and sequestration processes shall be established. This includes documents indicating the date (month/yr), CO_2 volumes sold by the supplier, transported, and received by the EOR operator. The documentation shall be maintained by the Project Proponent and provided during verification. The documents shall be retained for a minimum period of 3 years following the end of the crediting period.

6.3 Permanence, Liability, and Mitigation

For CCS projects, Project Proponents must demonstrate that the CO_2 captured and stored is permanently sequestered underground. The post-injection monitoring tasks as described in Section 5.4 will be conducted for the Project Term defined in Section 2.2. Post-Project Term requirements are described in Section 5.4.1. Site characterization coupled with the use of site-specific monitoring and modeling provides data and information for the operator to calibrate, validate and compare the model over the Project Term. This model will be used as a predictive tool to monitor and track the CO_2 plume during the post-injection period and beyond. The predictions will be confirmed by measurements of pressure and/or other relevant parameters made during the remainder of the Project Term (post-injection phase). As indicated in Section 5.4, no leakage is assured when it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO_2 will remain contained within the storage volume.

An operator shall prove financial responsibility prior to gaining a permit to begin active injection operations. This effort establishes a plan for safe operation of injection activities. Implementation of this safety plan throughout operations should mitigate long-term liabilities. Appendix D includes a listing of laws that have been enacted and/or bills that are currently pending in the State legislatures at the time of publication of the methodology related to liability and pore space ownership issues in CCS projects.

Long-term liabilities arise from migration of the CO_2 plume, either vertically through well bores, fractures, or faults or horizontally by moving to points of leakage. Over time, project uncertainties can be greatly reduced through a well-designed monitoring program. As uncertainties are addressed and reduced, confidence in the location of CO2 plume in the reservoir increases over years of MRV operations.

Migration of CO_2 plumes might qualify as trespass or nuisance under State law. The oil industry has addressed this liability during EOR and the issue of trespass has been addressed in a Texas case (Texas Railroad Commission v. Manziel)[53], which held that injection associated with a state-authorized secondary recovery project would not cause trespass. This was decided even though fluids move across property lines. In other States, this issue would be dependent on individual State regulations and statutes.

While the lateral migration of CO_2 outside the confining zone could indicate that modifications to the project's MRV are necessary, these events should not disqualify or affect the project's emission reductions as long as there is no leakage to the atmosphere.

If a CO_2-EOR project has a leak which causes damage, the operating Company may be liable in criminal or civil courts. Case law has built up around claims associated with subsurface injection and liabilities can be managed through the existing legal system. To cover liability of atmospheric leakage, Project Proponents can purchase private insurance designed to cover damages associated with releases, including third-party liability and liability to ACR, and those resulting from lost credits due to reversals. Insurance premiums would be paid by the Project Proponent 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 and retire ACR offset credits).

In lieu of insurance, Project Proponents may opt to create a Reserve Account. Each year the Project Proponent would deposit 10 (ten) percent of the project's offset credits in the Reserve Account. In the event of reversals, a debit shall be measured and reported, verified, and reconciled by the Account by retiring offset credits from the Reserve Account. To provide flexibility, contributions to the Reserve Account need not come from the project itself whose risk is being mitigated. A Project Proponent may make its contribution in ACR offset credits of any type and vintage.

If atmospheric leakage occurs, remediation will be conducted in accordance with the site-specific remediation plan, and any leaks to the atmosphere shall be estimated and mitigated. The procedures for mitigation of atmospheric leakage during the injection and post-injection periods are summarized in Table 6-1. If a small release (i.e., less than the estimated ERs for that year) occurs during the injection period and results in leakage to the atmosphere, then it shall be mitigated as project emissions in the same year using Equation 4-19. If the release is large and exceeds the ERs for that year, then a portion of

[53] Railroad Commission of Texas v. Manziel, 361 S.W. 2d 560 (Tex. 1962)

that release is mitigated as project emissions until ERs for that year are zero. The remaining release (i.e., unreconciled quantity) shall be compensated by liability insurance, or be reconciled through the retirement of an equivalent quantity of offset credits from the project's Reserve Account.

Table 6-1 Atmospheric Leakage Mitigation Procedures

Atmospheric Leakage Scenario	Required Mitigation
Project Term	
Injection Period: Leakage detected in year "y". where y ≤ n "n" = total years of injection	Handle as project emissions in year y using Eq. 4.19. If leakage exceeds year y ERs, then reconcile as project emissions in year y until GHG ERy = 0 (Eq. 4.21), and excess leakage (i.e., unreconciled leakage) is mitigated by one of the following options: 1. Use private insurance acceptable to ACR (see note), or 2. Upon offset credit issuance, contribute 10 % of the project's ERs/year or an equivalent quantity of ACR offset credits (of any type and vintage) into a Reserve Account; ACR will retire quantity to be mitigated from the Account.
Post Injection Period: Leakage detected in year "y" where y > n. "n" = total years of injection	Project Proponent shall choose one of the following options: 1. Use private insurance acceptable to ACR (see note), or 2. Upon offset credit issuance, contribute 10 % of the project's ERs/year or an equivalent quantity of ACR offset credits (of any type and vintage) into a Reserve Account; ACR will retire quantity to be mitigated from the Account
Post Project Term	
A release of stored CO_2 that is intentional or that is a collateral effect of planned activities that affect the storage volume	Per the Risk Mitigation Covenant or an alternative risk mitigation assurance approved by ACR, prior to any release of stored CO_2 as described in the Covenant, ACR must be compensated through replacement deposit of the full amount of offset credits issued to the project during the Project Term, allowing ACR to retire such offset credits. If an intentional or collateral release occurs for a project with offset credits subject to Invalidation, ACR may invalidate such offset credits if replacement offset credits are not deposited for retirement by ACR.
Note: Any private insurance policy must be evaluated and approved by ACR to make sure there are no exclusions, term limitations, or liability limits that leave ACR exposed. Only once ACR accepts the insurance product will ACR waive contributions to the Reserve Account.	

If atmospheric leakage occurs during the post-injection period, then the Project Proponent shall mitigate the leaked quantity by liability insurance or by the retirement of an equivalent quantity of offset credits from the project's Reserve Account.

Project Proponents shall indicate their mitigation strategy (i.e., insurance or Reserve Account) in their GHG Project Plan. If Project Proponents choose to mitigate by insurance, then that insurance product must be approved by ACR as indicated in Table 6-1. If Project Proponents choose to mitigate by contributions to an Reserve Account, those contributions shall begin from the start of offset crediting and shall constitute 10% of the project's ERs each issuance, or an equivalent quantity of ACR offset credits (of any type and vintage).

In the event that atmospheric leakage exceeds the Reserve Account contributions or the coverage provided by insurance, the Project Proponent shall mitigate any unreconciled quantity through deposit of sufficient ACR offset credits for ACR's retirement (of any type or vintage). If the Project Proponent does not deposit sufficient ACR offset credits to mitigate the leakage within 45 days, then ACR retains the right to freeze the Proponent's project account and retire any existing offset credits to mitigate the unreconciled quantity.

6.4 Pore space ownership

CCS Project Proponents may need to own or obtain rights to the subsurface pore space where CO_2 will be injected and sequestered. In the U.S., with the exception of federal lands, the acquisition of storage rights, which are considered property rights, generally is a function of State law. In many States, no clear property right to use pore space has been assigned to surface property owners covering the injection of fluids into deep geological formations. Such injection under the underground injection control (UIC) program goes on without approval from surface land owners except for those on whose property the injection well is located. These projects appear to have adopted the "inverse rule of capture" rule that allows project owners to be held non-liable if their injected fluids trespass into the subsurface of neighboring properties as long as their injection was in accordance with a federal or state-approved program. In effect the subsurface rights vest in whoever is able to assert them physically on a first-come basis.[54]

As indicated in Appendix D, while pore space ownership issues are beginning to be addressed through State law and regulation, those laws are not uniform. In the case of storage in non-EOR projects, some states, including Montana, Wyoming, and North Dakota, have assigned pore space ownership to the surface owners. In Wyoming and Montana, pore space ownership may be severed and assigned to the mineral owner. In Texas, mineral rights are severed from surface rights and there is no clear ownership of pore space between surface and mineral owners; although, it is likely that pore space is owned by surface owners.

[54] Carbon Capture and Sequestration: Framing the Issues for Regulation, CCSReg Interim Report, January 2009

In the case of CO_2 EOR projects, the right to inject CO_2 into the subsurface oil reservoir generally is contained in and part of the oil and gas lease that would have been obtained to develop the project. Therefore, the right to use an oil reservoir for the associated storage of CO_2 during the operational phase of a CO_2 EOR project would be permissible under an oil and gas lease.[55] Once injected and secured in the reservoir, the operator is not required to extract the injected CO_2 at the completion of the operational phase of the project.

Migration of any injected fluid is only permissible provided the migration is in compliance with regulations covering injection operations, does not interfere with preexisting mineral recovery operations, cause damage to any adjacent subsurface and overlying surface properties, or endanger public health and safety.[56]

In the case of EOR, it is typical that mineral lease rights and associated surface use rights expire following the end of hydrocarbon production activities. However, monitoring after the end of hydrocarbon extraction activities is needed as part of assuring no atmospheric leakage (Section 5.4). Project Proponents shall ensure that EOR operators have continued access to the surface to conduct post-injection monitoring activities and if necessary, remediation. Based on the site-specific monitoring planned for the post-injection period and associated surface access requirements, Project Proponents shall obtain needed surface use rights from the surface owners for the duration of the Project Term. This will usually entail surface use agreements similar to what is currently used to conduct groundwater remediation activities. Further, as required by Section 5.4.1, Project Proponents shall obtain the consent of surface owners to the filing of a Risk Mitigation Covenant or provide an alternative risk mitigation assurance acceptable to ACR, and if it does not do so, the offset credits issued for the project shall be subject to Invalidation.

6.5 Community and Environmental Impacts

CCS projects involve the installation of capture technologies, pipelines and gas separation and compression infrastructure. These CCS projects are capital-intensive and may require environmental assessments. If an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) is required, that document or a summary thereof shall be provided to ACR and provided to the VVB on request. There are different state and federal laws, regulations and guidance that require an EA or EIS for certain government actions, such as the federal Environmental Policy Act (NEPA) and state analogues. Project Proponents shall document in the GHG Project Plan a mitigation plan for any foreseen negative community or environmental impacts, and shall disclose in their annual Attestations any negative environmental or community impacts or claims of negative environmental and community impacts made during the reporting year. These claims include legal actions and/or other written complaints filed by affected parties.

[55] Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces, IOGCC, 2007.
[56] Carbon Capture and Sequestration: Framing the Issues for Regulation, Interim Report, CCSReg Project, January 2009

7.0 QA/QC

QA/QC procedures shall be implemented during all phases of the project to assure data quality and completeness. The USEPA has published Mandatory Greenhouse Gas Reporting requirements for various types of facilities that emit GHG.[57] General Provisions are contained in Subpart A. This methodology incorporates the requirements contained in Part 98.3(i) of Subpart A, *Calibration Accuracy Requirements*, which requires all measurement devices be calibrated according to the manufacturer's recommended procedures or an appropriate industry consensus standard to an accuracy of 5 percent. Calibration records shall be maintained and made available to third party verification.

For flow meters, all calibrations shall be performed at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters (which are described in the next paragraph of this section), the calibration error at each measurement point is calculated using Equation 7-1. The terms ''R'' and ''A'' in Equation 7-1 must be expressed in consistent units of measure (e.g., gallons/minute, ft^3/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.[58]

Equation 7-1: Calibration Error Calculation for Flow Meters

$$CE = (R-A)/R \times 100$$

Where,

CE	=	Calibration Error (%)
R	=	Reference Value
A	=	Flow meter response to the reference value.

For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. Each transmitter shall be calibrated at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. The calibration error of each transmitter at each measurement point is calculated using Equation 7-2. The terms ''R'', ''A'', and ''FS'' in Equation 7-2 must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 5.0 percent.

[57] Mandatory Greenhouse Gas Reporting, USEPA Code of Federal Regulations. 40 CFR Part 98
[58] Mandatory Greenhouse Gas Reporting, USEPA Code of Federal Regulations. 40 CFR Part 98.3(i)

Equation 7-2: Calibration Error Calculation for Flow Meter Transmitters

$$CE = (R-A)/FS \times 100$$

Where,

CE	=	Calibration Error (%).
R	=	Reference Value.
A	=	Transmitter response to the reference value.
FS	=	Full scale value of the transmitter.

Data on gas and liquid stream composition analysis shall include calibrations of the gas analyzer or other instrumentation used. If an outside third party laboratory is used, documentation of their accreditation to conduct the analysis shall be obtained.

Fuel billing meters are exempted from the calibration requirements, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company (USEPA 40 CFR Part 98.3(i)).

The methodology recommends additional procedures as part of the project's QA/QC program.
Data collection procedures (templates, logs, etc.) shall be developed to ensure site-specific data are collected in a timely fashion. Periodic reviews of the data for accuracy, completeness and consistency shall be conducted. As appropriate these procedures shall be included in the plant and storage site standard operating procedures (SOPs). If data are missing, the methodology recommends that Project Proponents follow missing data procedures contained in USEPA Subpart RR regulations.[59]

The MRV Plan to detect and assess subsurface leakage (if any) shall include quality checks on the data, models, etc. and report on significant deviations from expected values.

The GHG Project Plan shall include a section on QA/QC plan and procedures that will be followed to ensure data quality and completeness.

[59] USEPA Subpart RR, Geologic Sequestration of Carbon Dioxide, 40 CFR Part 98.445, Procedures for Estimating Missing Data.

8.0 UNCERTAINTIES

The emission reduction calculations in this methodology are designed to minimize the possibility of overestimation and over-crediting of GHG emission reductions, due to various uncertainties, primarily associated with fluid flow and composition analysis of gas and liquid streams, plant operating parameters, and accurate logs of emission leakage events maintained by site operators.

While some of these uncertainties are more easily quantified than others, the sources and relative magnitude of uncertainties (and changes thereof) shall be explicitly addressed and discussed by the Project Proponent and described in the GHG Project Plan as part of the GHG emissions calculation and reporting process.

Potential sources of uncertainty and the associated QA/QC program elements designed to minimize them are summarized in Table 8-1. Overall uncertainty can be assessed by using the uncertainties of each element in a calculation.

The accuracy and precision of measurement equipment, such as the flow meters, gas composition analyzers, process measurements (e.g., electricity and steam), are readily quantified and the uncertainties associated with each measurement are considered to be low.

The accuracy and completeness of site operator data on blowdown events and estimates of fugitive emission losses depend on meticulous logs maintained by the operator. The uncertainty in these parameters is considered low since site operators are currently required to report these data to the USEPA as part of their reporting requirements under Subpart W.[60] Operators that are exempt from Subpart W reporting shall follow procedures contained in subpart W to estimate losses from blowdown events and fugitive emissions.

The uncertainty in detection and assessment of leakage from the subsurface to the atmosphere is dependent on the design and implementation of a site's MRV Plan. For EOR sites, the geologic storage site is generally well characterized and modeled. The development of a site-specific MRV Plan, that identifies possible leakage pathways and utilizes a proper set of monitoring tools to provide assurance of containment and to detect leakage, should it occur, is critical. There is a wealth of oil and gas industry experience in the design and implementation of proper monitoring tools, many of which are currently being utilized to optimize production. Based on the implementation of a well-designed MRV Plan, the uncertainty in detection and measurement of leakage is considered low for EOR sites.

[60] Under Subpart W, owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 tonnes or more of GHGs per year must report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. It includes the reporting of venting and fugitive emissions from onshore petroleum and natural gas production facilities, such as EOR operations.

Table 8-1 Potential Sources of Uncertainty

Data Parameter	Uncertainty Level of Data	Comments
Vol. $_{\text{Gas Produced}}$ **Vol.** $_{\text{Gas Transferred}}$ **Vol.** $_{\text{Gas Received}}$ **Vol.** $_{\text{Gas Supplied}}$ **Vol.** $_{\text{Gas Sold (fuel)}}$ **Vol** $_{\text{CO2_Transfer}}$	Low	Extensive industry experience with flow meters used for this application. Flow meters shall be installed and operated in accordance with manufacturer's specifications. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
%CO_2 **% CO_2** $_{\text{Gas Sold (fuel)}}$	Low	Industrial processes producing CO_2 are well controlled so minimal variability of CO_2 concentrations in gas stream. Direct measurement of the composition of the gas stream shall be made on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
Output	Low	Measurements based on the type of primary process. Output shall be measured using instrumentation that shall be calibrated in accordance with manufacturer's specifications.
Fuel i **Total Fuel Cogen**	Low	For gaseous fuels, daily measurement of the gas flow rate. Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications. For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fossil fuels consumed to operate the CCS
Mass Frac. $_{\text{Carbon i}}$	Low	Direct measurement of the carbon content of the fuel using industry accepted practices.
Electricity **Electricity CCS Project** **Electricity Cogen**	Low	Continuous measurement of electricity consumption using meters calibrated by an accredited party per manufacturer's specifications. If third party utility billing records are used, those measurements are usually based on well calibrated meters. If estimated from maximum kW rating for each type of equipment and operating hours, the uncertainty in energy usage is greater, however the estimates will be conservatively higher.

Data Parameter	Uncertainty Level of Data	Comments
Heat CCS Project **Heat Cogen**	Low	Daily metering of thermal energy sales/purchases to/for the CCS project using meters calibrated by an accredited party per manufacturer specifications.
$N_{Blowdown\ i}$ $V_{Blowdown\ i}$	Low	Based on storage site operator's detailed logs of all venting incidents. Volume estimates are based on pipeline diameters and flow conditions and duration of events. Operators are required to log and report these data under federal (USEPA Subpart W) and most State regulations.
$\%GHG_j$	Low	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
$Count_s$ T_s	Low	Storage site operator shall develop and maintain an equipment inventory of all possible fugitive emission sources from surface facilities at the storage site and operational time. Operators are required to report these data to the USEPA per Subpart W requirements.[61]
Mass $_{Water\ Prod}$ **Mass** $_{Oil\ Prod}$	Low	Data on water production and injection rates, which are measured with calibrated flow meters, are routinely maintained by operators. Monthly reconciliations of water disposal records are routinely conducted. Oil or other hydrocarbon production values are based on continuous, daily, or monthly measurements. Data can be obtained from reconciliation of oil or other hydrocarbon sales from facilities associated with the producing formation.
Mass Frac $_{CO2\ in\ Water}$ **Mass Frac** $_{CO2\ in\ Oil}$	Low	Data obtained from periodic lab analysis of produced water and produced oil samples using industry accepted practices.
CO_{2Z}	Low	CO_2 leakage (if any) from the geologic reservoir to the atmosphere would be estimated based on monitoring and measurements completed per the CCS project's MRV Plan. For oil and gas producing reservoirs that have been extensively characterized, modeled, and monitored considering potential failure scenarios, the uncertainty in detecting and estimating leakage is low.

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

APPENDIX A - ENHANCED OIL RECOVERY OVERVIEW

Crude oil development and production in U.S. oil reservoirs has included three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. After primary and secondary techniques have been used to recover the easy-to-produce oil, producers have attempted several tertiary, or EOR, techniques.

Three major categories of EOR have been found to be commercially successful to varying degrees depending on the oil and reservoir properties and implementation costs:

- Thermal recovery, which involves the introduction of heat such as the injection of steam to lower the viscosity, or thin, the heavy viscous oil, and improve its ability to flow through the reservoir. Thermal techniques account for over 40 percent of U.S. EOR production, primarily in California.

- Gas injection, which uses gases such as natural gas, nitrogen, or carbon dioxide that expand in a reservoir to push additional oil to a production wellbore, or that dissolve in the oil to lower its viscosity and improves its flow rate. A description of CO_2 injection for EOR is included in this section. Gas injection accounts for nearly 60 percent of EOR production in the United States.

- Chemical injection, which can involve the use of long-chained molecules called polymers to increase the effectiveness of waterfloods, or the use of detergent-like surfactants to help lower the surface tension that often prevents oil droplets from moving through a reservoir. Chemical techniques account for about one percent of U.S. EOR production.[62]

The injection of CO_2 into oil reservoirs for EOR has been performed by the oil industry for more than 40 years. CO_2 EOR is based on the concept of miscible or immiscible displacement of oil by CO_2. A typical CO_2 flood operation is shown in Figure 1. CO_2 is compressed to supercritical conditions and injected into injection wells that are strategically placed within the pattern of wells across the areal extent of the reservoir. The injected CO_2 enters the reservoir and moves through the pore spaces of the rock, encountering residual droplets of crude oil, becoming miscible with the oil, and forming a concentrated oil bank that is swept towards the producing wells. At the producing wells—and there may be three, four or more producers per injection well—oil mixed with water and gas is pumped to the surface, where it flows to a centralized collection facility. The produced fluid containing oil, water, gas, and CO_2 is separated at the surface. Any produced CO_2 is re-compressed and re-injected along with additional volumes of newly purchased CO_2. The separated produced water is treated and re-injected, often alternating with CO_2 injection, in a water-alternating-gas (WAG) process.[63]

[62] http://energy.gov/fe/science-innovation/oil-gas/enhanced-oil-recovery
[63] Carbon Dioxide Enhanced Oil Recovery, US DOE, NETL, http://www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2_EOR_Primer.pdf

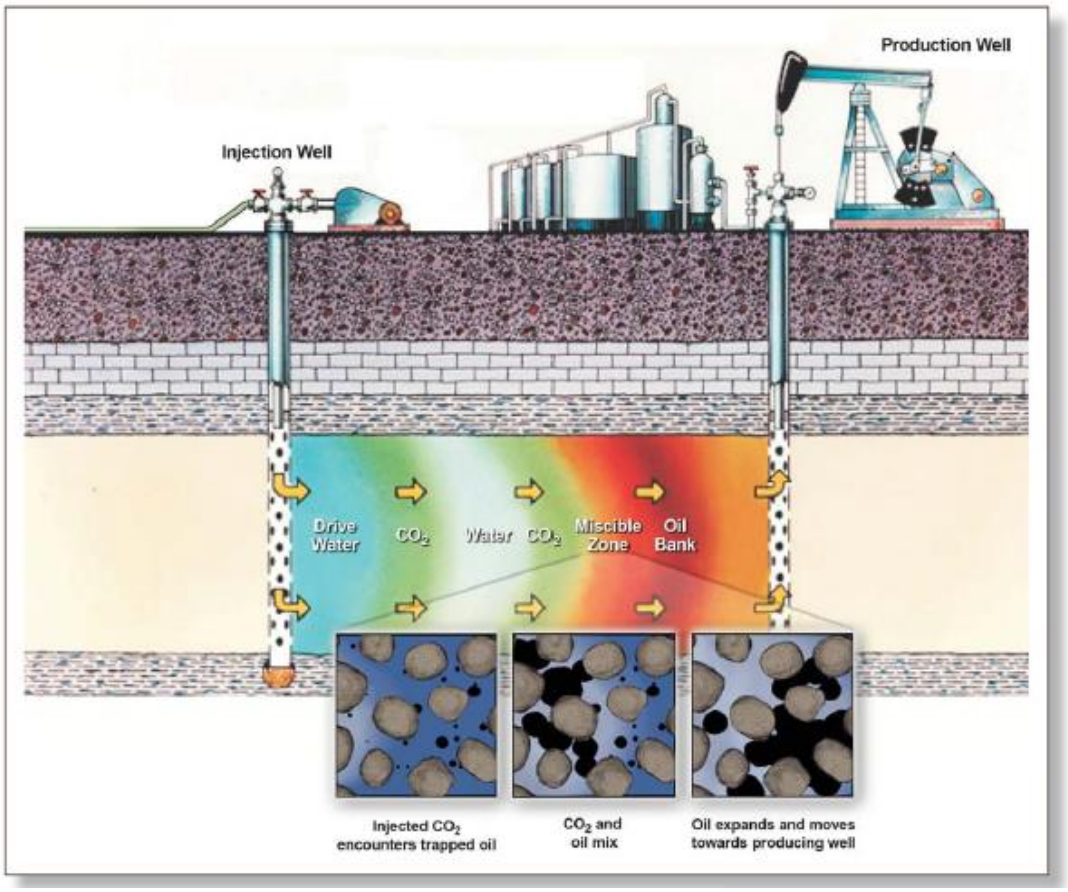


Figure A-1 Typical EOR process using CO_2 and water in a water-alternating-gas (WAG) process

An operator implementing an EOR project with CO_2 is highly motivated to track and contain all the CO_2 purchased as it is expensive. If the CO_2 is lost out of the producing zone or vented to the atmosphere, the operator will have to purchase additional CO_2. This means the operator is motivated to design the EOR project to minimize the loss of any CO_2 either in the oil reservoir or in the surface production facilities.

When CO_2 is injected into the reservoir, it is generally injected at a pressure that results in total or partial miscibility with the oil in the reservoir. A portion of CO_2 will become soluble (mixed) with the oil and be recovered when the oil is produced. Of the remaining CO_2 injected, some of the CO_2 will be permanently trapped in the rock's pore space, some will become dissolved in the formation brine, and the remainder will migrate within the reservoir. The CO_2 that is trapped in the rock's pore space is effectively sequestered forever. The CO_2 that is not trapped in the pore space and not mixed with the oil tends to migrate to the upper regions of the oil reservoir, as it is lighter than the oil and water in the formation. However, it remains contained in the oil reservoir because of the confining layer above the oil reservoir that traps it in place. This is the same confining layer that formed an effective seal and contained the oil and gas in the reservoir for millions of years and now serves to trap the CO_2.

The CO_2 that is produced with the oil will separate from the oil at the surface and be captured. This captured CO_2 is then compressed and re-injected into the oil reservoir where the process starts all over again. The EOR operator maintains tight control over CO_2 at the surface facilities to minimize any losses as it is expensive to lose the CO_2. In addition, the CO_2 can be effectively measured and monitored while being handled in the surface facilities.

APPENDIX B- 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. 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 B-1

$$CO_{2_{T,x}} = \sum_{p=1}^{4} (Q_{x,p}) x C_{CO_2,p,x}$$

Where:

$CO_{2_{T,x}}$ = Net annual mass of CO_2 measured by flow meter x (metric tons).

$Q_{x,p}$ = Quarterly mass flow through meter x in quarter p (metric tons).

$C_{CO_2,p,x}$ = Quarterly 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 B-2

$$CO_{2T,x} = \sum_{p=1}^{4} (Q_{x,p}) x D x C_{CO_2,p,x}$$

Where:

$CO_{2T,x}$ = Net annual mass of CO_2 measured by flow meter x (metric tons).

$Q_{x,p}$ = 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): 0.0018682.

$C_{CO_2,p,x}$ = Quarterly 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 B-3

$$CO_2 = \sum_{x=1}^{X} CO_{2T,x}$$

Where:

CO_2 = Total mass of CO_2 measured by all flow meters in year y (metric tons).

$CO_{2T,x}$ = Total mass of CO_2 measured by flow meter x, as calculated in Equation A-1 or Equation A-2 in year y (metric tons).

X = Total number of flow meters.

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 B-4

$$PE_{Elec,\,y} = \sum (Electrical\ Rating_i \times Hours_i \times Load_i) \times EF_{Electricity}$$

Where,

$PE_{S\text{-}P\text{-}Elec,\,y}$	=	Project emissions from electricity used to operate equipment at the CO_2 storage site in 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, by (in order of preference) PCA, eGRID subregion, or State (tCO_2e/MWh).-See Section 4.2.1 for estimation procedures.

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 B-5

$$\mathbf{CO_2\ Produced_{PP,\,y} = \sum(Fuel_i \times Mass\ Frac_{Carbon,\,i} \times 44/12)}$$

Where,

$\mathbf{CO_2\ Produced_{PP,\,y}}$	=	Gross amount of CO_2 produced from the primary process in each year (tCO_2/yr).
$\mathbf{Fuel_i}$	=	Total volume or mass of fuel, by fuel type i, input into the primary process in year each (e.g., m^3 or kg).
$\mathbf{Mass\ Frac_{Carbon,\,i}}$	=	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 situations where a flare is used to combust gases produced from the formation (e.g., gases that may contain CO_2 that originate from the capture site).

Equation B-6

$$\mathbf{PE_{Flaring,\,y} = \sum(Gas\ Flared_i \times \sum(C_i \times y_i) \times 44.01/23.64) + \sum(Flare\ Fuel_i \times EF\ CO_{2\ Flare\ Fuel\ i}) + \sum[Gas\ Flared_i \times (1\text{-}DE) \times \%CH_4 \times \rho\ CH_4) \times CH_4\text{-}GWP + \sum(Flare\ Fuel_i \times \%CH_4 \times \rho\ CH_4 \times (1 - DE))] \times CH_4\text{-}GWP + \sum(Vol._{Gas\ Flared} \times EF\ N_2O_{Gas\ Flared\ i}) + (Flare\ Fuel_i \times EF\ N_2O_{Flare\ Fuel\ i})] \times N_2O\text{-}GWP}$$

Where,

$\mathbf{PE_{Flaring,\,y}}$	=	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.
$\mathbf{Gas\ Flared_i}$	=	Volume of gas flared at hydrocarbon production facilities at the storage site in year y (m^3/year).
$\mathbf{Flare\ Fuel_i}$	=	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).
$\mathbf{C_i}$	=	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)
$\mathbf{y_i}$	=	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).
ρ CH_4	=	Density of CO_2 at standard conditions = 0.00190 metric ton/ m^3.
EF N_2O 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 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 Flare Fuel I	=	N_2O 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).
CH_4-GWP	=	Global Warming Potential of CH_4.
N_2O-GWP	=	Global Warming Potential of N_2O.

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 B-1 Surface Components as Potential Emissions Sources at Injection Facilities[64]

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

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

APPENDIX C - STANDARDS AND PROCEDURES FOR CLASS II WELLS IN TEXAS

The official rules of the Railroad Commission of Texas are found in the Texas Administrative Code (TAC) Title 16, Part 1, Chapters 1-20.[65] Chapter 3 includes rules of the Oil and Gas Division. Under Statewide Rules 9, 46, 95, 96, and 97, operators of injection and disposal wells associated with oil and gas exploration, production, transportation, or underground storage Class II wells must obtain a permit from the Railroad Commission. Thus, all Class II wells in Texas must be approved by the Commission before injection operations can legally begin. Pursuant to Rules 9, 46, 95, 96, and 97, and the applicable application forms, such permits will be approved only if the applicant satisfies the burden of showing that fresh water will be protected.

Once a permit is granted, the operator is bound by all applicable Commission rules and permit conditions by virtue of accepting the right to operate pursuant to the permit. It is necessary to examine permit conditions, as well as statewide rules, in order to determine what actions are necessary for compliance.

Types of Permits

Permits to dispose of salt water or other oil and gas wastes by injection into porous formations that are **not** productive of oil, gas, or geothermal resources are issued under Statewide Rule 9. Form W-14 is used to apply for this type of permit.

Permits to inject water, steam, gas, oil and gas wastes, or other fluids into porous formations that are productive of oil, gas, or geothermal resources are issued under Statewide Rule 46. Forms H-1 and H-1A are used to apply for this type of permit.

Permits to conduct hydrocarbon storage operations are issued under Statewide Rules 95, 96, or 97. Form H-4 is used to apply for these types of permits.

Commercial Disposal Wells

A commercial disposal well is a well whose owner or operator receives compensation from others for the disposal of oilfield fluids or other oil and gas wastes that are wholly or partially trucked to the well and the primary business purpose of the well is to provide these services for compensation. Permits for commercial disposal wells contain special conditions for surface facilities associated with waste management.

Permitting Process

All permit applications for Class II wells come to the Technical Permitting Section, where they are evaluated and processed. If a hearing is requested or required, the Technical Permitting Section requests that a hearing be scheduled, and the Commission provides notice to all interested persons.

[65] http://www.rrc.state.tx.us/rules/rule.php

After the hearing, the examiners recommend final action to the Commissioners, who decide if the permit will be issued. If no protests are received on an application, the Director of Technical Permitting may administratively approve the application.

See the section titled "Injection and Disposal Well Permitting" for more detail on permitting standards and procedures.

Transfer and Modification of Permit

An injection or disposal well permit may be transferred only after notice to the Commission. Written notice of intent to transfer the permit must be submitted to the Commission on Form P-4 at least 15 days prior to the date the operators plan for the transfer to occur. Permit transfer will not occur until the Form P-4 has been approved by the Commission.

An injection or disposal well permit may be terminated, suspended, or modified for just cause, such as a substantial change in well completion or operation, pollution of fresh water, substantial violations of permit conditions or rules, misrepresentations by the applicant, or the escape of injected fluids from the authorized zone. Notice and opportunity for hearing are provided in the same manner as in the initial permit process.

Geological Requirements

The authorized injection or disposal strata must be isolated from overlying usable quality water by a sufficient thickness of relatively impermeable strata, which is generally considered to be an accumulative total of at least 250 feet of clay or shale. Variances in the total thickness required are considered on the basis of continuity of strata, thickness of individual strata, or the presence of relatively impermeable strata other than clay or shale. No injection or disposal well will be permitted where faults, fractures, structure, or other geologic factors indicate that isolation of the authorized injection or disposal zone is jeopardized. The operator must submit adequate geological information to show compliance with this requirement.

Casing and Cementing

Injection and disposal wells must be cased and cemented in accordance with Statewide Rule 13 to prevent the movement of fluids into sources of fresh water. Rule 13 requires that surface casing be set and cemented to protect fresh water strata, as defined by the Texas Commission on Environmental Quality (TCEQ), formerly the Texas Natural Resource Conservation Commission. Cement is required to be circulated to the surface by the pump and plug method, and the specifications for cement quality and casing integrity set out in the rule must be met.

Injection and disposal wells must also meet UIC criteria for adequacy of cement to confine injected fluids. These criteria are 100 feet of well bonded cement as determined by a bond log, 250 feet of cement as evidenced by a temperature survey, or 400 to 600 feet of cement as determined by a slurry yield calculation. The flexibility in calculated annular footage allows for consideration of the operating conditions, type of cement used, and characteristics of the formation.

Wells that are converted from producers to injection into the same productive formation usually meet UIC cementing requirements if they were completed in compliance with Rule 13.

Area of Review

Statewide rules require that an applicant for an injection or disposal well permit examine the data of record for wells that penetrate the proposed injection zone within a one quarter (1/4) mile radius of the proposed well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids into strata other than the authorized injection or disposal zone. A permit applicant must submit a map showing the location of all wells of public record within 1/4 mile as part of the permit application. For those wells that penetrate the top of the injection or disposal zone, the applicant must attach a tabulation of the wells showing the dates the wells were drilled and the present status of the wells. Alternatively, if the applicant can show, by computation, that a lesser area will be affected by pressure increases, then the lesser area may be used in lieu of the fixed radius. In addition, an applicant may seek a variance from the Area of Review requirements by demonstrating that no significant increase in risk of groundwater contamination will result from the variance. No permit will be issued where the information submitted indicates that fresh water resources will be endangered unless permit conditions require appropriate corrective action in the area (e.g. remedial cementing, re-plugging inadequately plugged area wells, or more frequent testing and monitoring).

Standard Equipment Requirements

All newly drilled or converted injection wells permitted under Rule 46 and all disposal wells permitted under Rule 9 must be equipped with tubing set on a mechanical packer unless an exception is granted by the director for good cause. Pressure observation valves are required on the tubing and each annulus.

Operating Requirements

Maximum injection pressure limitations have been part of the Commission's permitting program for many years and continue to be required as a condition of each injection or disposal well permit. Pressure limitations are established to provide adequate assurance that injection will not initiate fractures in the confining zones. The maximum surface injection pressure may not ordinarily exceed 1/2 psi per foot of depth to the top of the authorized injection or disposal interval. A fracture pressure step-rate test must be performed to justify a higher pressure.

Monitoring and Reporting

The operator of each injection or disposal well is required by the statewide rules to monitor the injection pressure and volume on a monthly basis and to report the results annually on Form H-10. Any downhole problem that indicates the presence of leaks in the well must be reported to the appropriate district office within twenty-four (24) hours.

See the section titled "Injection and Disposal Well Monitoring" for more detail on monitoring requirements.

Mechanical Integrity

All injection and disposal wells must be pressure tested before injection operations begin, after any workover that disturbs the seal between the tubing, packer, and casing, and at least once every five (5)

years to determine if leaks exist in the tubing, packer, or casing. Some permits require more frequent tests, such as annual pressure tests for converted wells with short surface casing. The appropriate district office must be notified before any pressure test to allow a Commission representative to witness the test. The operator must then file a record of the test with the district office (Form H-5) within 30 days of the test. As an alternative to the five-year pressure testing, the operator may monitor the casing-tubing annulus pressure and report the results annually if the reported information demonstrates mechanical integrity and provided that the well is pressure tested at least once every ten (10) years.

Wells not equipped with tubing and packer or with other non-standard completions may require special down hole surveys to demonstrate mechanical integrity. These surveys must be approved in advance for a specific wellbore by Technical Permitting in Austin unless they are expressly required by the injection/disposal well permit.

See the section titled "Injection and Disposal Well Mechanical Integrity Testing" for more detail on mechanical integrity testing requirements.

Completion Reports

A completion report (Form W-2 or G-1) must be filed with the appropriate district office within thirty (30) days of completion or conversion to disposal or injection to reflect the new or current completion.

Exceptions

The statewide rules allow the director to grant exceptions to tubing and packer, packer setting depth, and pressure observation valve requirements of the rules upon proof of good cause. In addition, the district office may grant an exception to the surface casing requirements of Statewide Rule 13 and authorize use of the multistage completion process. Multistage cementing (in lieu of setting surface casing) is not normally authorized as a means to protect fresh water strata for wells drilled expressly as injection or disposal wells.

Plugging and Abandonment

All injection and disposal wells are required to be plugged upon abandonment, in accordance with Statewide Rule 14. A notice of intention to plug and abandon (Form W-3A) must be filed with the appropriate district office and received five (5) days prior to the beginning of plugging operations. Plugging operations may not begin prior to the date shown on the Form W-3A unless authorized by the District Director.

The general requirements of Rule 14 ensure the protection of all formations bearing fresh groundwater, oil, gas, or geothermal resources. Each well is also subject to the specific requirements of Rule 14 that are applicable to the particular well completion situation. Special plugging requirements that are specific to the well, field, or area may apply at the discretion of the District Director.

Within thirty (30) days after a well is plugged, a complete record (Form W-3) must be filed in duplicate with the appropriate district office.

APPENDIX D - STATE LEGISLATIVE ACTIONS[66]

SOUTHERN STATES ENERGY BOARD

Carbon Capture and Sequestration Legislation

In the United States of America

Introduction

At the time of publication, there were 23 states with Carbon Capture and Storage (CCS) related legislation, which are: AZ, MI, NY, PA, CA, IL, KY, MN, OK, VA, CO, FL, IN, KS, LA, MS, MT, ND, NM, TX, WA, WV and WY.

Four states had CCS Bills Pending as of 2011, which are: AZ, MI, NY and PA.

While coal power is associated mainly with the Midwest and Appalachian regions, the states with CCS legislation represent a comprehensive cross section of the country. States differ on their approach to enforcing these bills. Some states, such as Texas, are pushing full steam ahead, yet others, like Montana, awaited an EPA final rule. Some tackle the statute first and regulations second (Wyoming, North Dakota), while others are working to create legislative recommendations (Utah, Illinois, West Virginia). Kansas, among others, has concluded that existing legislative authority is sufficient and is able to move directly to promulgation of final regulations.

This study on state CCS legislation does not include every element addressed by these bills. Instead, it is intended to give an overview of four key areas identified as necessary elements of a broader comprehensive regulatory framework governing CCS activities. The key areas are Project Authority, Pore Space and Carbon Dioxide (CO_2) Ownership, Liability and Financing Sources.

Project Authority: This area addresses which state regulatory agency (SRA) will be charged with developing and administering rules and regulations governing CCS projects. The agency must have the authority to require compulsory joining of all participating interests in the underground storage reservoir and have appropriate permitting authority to require and operator to submit any data necessary to evaluate a proposed CO_2 storage project. Examples of such SRAs are state oil and gas regulatory agencies, state environmental agencies or state public utility commissions.

Pore Space and CO2 Ownership: This area addresses who has the property rights to inject CO_2 into wells and who owns the CO_2 in case of unintended trespass. The right to use reservoirs and associated pore space is considered a private property right in the United States and must be acquired from the owner of those rights. To determine this, states are most likely to follow their traditional common law approach in determining these rights and, in most cases, pore space is deemed to be owned by the surface estate. CO_2, on the other hand, is treated like any other commodity and, in general, is owned by the injector.

Liability: This area addresses what party is liable for the injected CO_2 both during the injection, the closure and the long-term, post closure phase. What party is liable depends, therefore, on the phase of the project. The injection phase is the period of time during active injection. The closure period is the time when the plugging of the well is completed and continues until a future date is reached, usually 10 years after injection activities and the wells are plugged. During these phases, the operator is the liable party. The post closure phase is the period of time beginning when the project is deemed complete, usually marked by the issuance of a Certificate of Completion, and extends for the life of the well. During this phase, liability transfer to the state for monitoring, verification and remediation activities. The injector is then usually released from all liability.

Financing Sources: This area addresses both the costs of the CO_2 injection projects themselves and the long-term costs. For the costs associated with the injection project, many states will give tax incentives in the form of sales tax, income tax or property tax exemptions for qualifying endeavors. Many states have established some type of CCS trust fund to pay for the expense of long-term monitoring, verification and remediation. These trusts tend to be state administered and industry funded on a cost per ton basis.

[66] July 2011 - Southeast Regional Carbon Sequestration Partnership and Southern States Energy Board

State	Bill (year)	Project Authority	Pore Space/CO_2 Ownership	Liability	Financing Source
AZ	SCR 1033 (2011) Pending	Arizona Department of Environmental Quality (ADEQ)			ADEQ is urged to allow the use of commercially available technologies that are designed to be as efficient as is economically practicable, including advanced super-critical pulverized coal, ultra super-critical pulverized coal, and that are designed to be carbon capture and sequestration-compatible, as potential best available control technology.
CA	SB 669 (2011) Pending	State Energy Resources Conservation and Development Commission			Provides for the full recovery in rates of long-term commitments entered into through a contract approved by the commission for electricity generated by zero- or low-carbon generating resources demonstrating new technology, if the commission determines that the commitment would benefit the state's ratepayers, economy, and the environment.
CA	A 1504 (2010) Enacted	Board of Forestry and Fire Protection			Permits fees collected under the Global Warming Solutions Act of 2006 to be used for related studies and analyses.
CO	HJR 1028 (2010) Enacted	U.S. Congress			Urges the United States Congress to pass comprehensive legislation that promotes clean energy jobs and addresses the effects of climate change including CCS technology.
CO	HB 06-1281 (2006) Enacted				Creates a CCS program and provides incentives for IGCC plants.
FL	HB 549 (2007) Enacted Ch. No. 2007-117				Provides incentives for IGCC plants.
IL	SB 1567 (2011) Pending	Carbon Capture and Sequestration Legislation Commission	To be determined by the Commission.	To be determined by the Commission.	
IL	SB 1821 (2011) Enrolled	Illinois Commerce Commission	Pipeline owners	Pipeline owners	Funding is provided by CO_2 pipeline owners.
IL	SB 678 (2010) Enacted P.A. 96-1491	FutureGen Alliance	Title transfers once injected.	FutureGen has limited liability which only arises out of or resulting from the storage, escape, release, or migration of the post-injection sequestered CO_2.	State aided in securing $1billion for FutureGen.
IL	SB 3686 (2010) Sine Die	Illinois Power Agency	"Initial Clean Coal Facility" or the Illinois Power Agency if requested.	Utility and alternative electric suppliers will have limited liability while in commercial operation.	Requires offsetting of excess emissions.
IL	P.A. 92-0012 (2002) P.A. 93-0167 (2004) P.A. 94-65 (2005) P.A. 94-1030 (2006) P.A. 95-18 (2007)				Incentives for IGCC plants.
IL	SB 1987 (2008) Enacted P. A. 95-1027				Illinois power agency may fund or operate sequestration facility.
IL	SB 1592 (2007) Enacted P. A. 95-0481				Incentives for advanced coal plants in locations where geology is suitable for sequestration.
IL	SB 1704 (2007) Enacted P. A. 95-0018		Illinois to take title to injected carbon dioxide from the FutureGen project.	State assumes any liabilities associated with the sequestered gas both during operation and for long-term liability, as well as any current or future environmental benefits, marketing claims, tradable credits, emissions allocations or offsets.	Exempts the FutureGen project from Illinois tax on electrical generating units.

State	Bill (year)	Project Authority	Pore Space/CO_2 Ownership	Liability	Financing Source
IN	P.L. 105-1989 (1989) P.L. 159-2002 (2002) P.L. 174-2005 (2005) P.L. 191-2005 (2005) P.L. 175-2007 (2007)				Incentives for clean coal technology.
KS	HB 2418 (2010) Enacted Ch. No. 2010-63	State Corporation Commission		Exempts the Commission and the state from assuming liability for the underground storage of carbon dioxide or the maintenance of any carbon dioxide injection well or underground storage of carbon dioxide except as permitted by the Kansas tort claims act.	Fees may be collected by the commission and put into the "carbon dioxide injection well and underground storage fund."
KS	HB 2419 (2007) Enacted	State Corporation Commission			Property and income tax incentives for CCS.
KS	SB 303 (2006) Enacted				Incentives for IGCC, such as tax credits and an amortization deduction in an amount equal to 55% of the amortizable costs of such new qualifying pipeline for the first taxable year in which such new qualifying pipeline is in production, and 5% of the amortizable costs of such new qualifying pipeline for each of the next nine taxable years.
KY	SB 50 (2011) Enacted KRS 154.27	Pipeline Company	Grants companies constructing carbon dioxide transmission pipelines eminent domain powers.		
KY	HB 259 (2011) Enacted KRS 353.1-.7	Energy and Environment Cabinet		Liability for stored carbon dioxide will pass to the federal or state government.	
KY	HB 1 (2007) Pending				Tax incentives for advanced coal plants.
LA	HB 495 (2010) Enacted Act 193, R.S. 9:1103		Monetary compensation is provided to the owner unless given by a contract or related to Coastal Protection and Restoration Authority.		
LA	HB 733 (2010) Enacted Act 527, R.S. 3:1221	Office of Soil and Water Conservation			Office is to participate in CCS programs.
LA	HB 661 (2009) Enacted Act 517	Office of Conservation	CO_2 ownership matter of private contract.	Operator is liable during operation; state assumes ownership 10 years after injection is complete; operators and others with interest are released from future liability.	
LA	HB 1117 (2008) Enacted Act 315	State Mineral Board	CO_2 owned by operator.		
LA	HB 1220 (2008) Enacted Act 315			State Mineral Board may operate and assume responsibility for facilities.	
MI	HB 4399 (2011) Pending	Department of Environmental Quality	Owner(s) having a property interest.		Fees will be put into the "Mineral Well Regulatory Fund."
MI	HB 4401 (2011) Pending	Department of Environmental Quality	Owner(s) having a property interest.	Project owner is immune from civil liability.	CCS project funded by the Owner and must be approved by the Department.

State	Bill (year)	Project Authority	Pore Space/CO_2 Ownership	Liability	Financing Source
MI	HB 6522 (2010) Pending	State Tax Commission	CCS equipment is seen as industrial property.		
MI	HB 4016 (2009) Pending	Department of Environmental Quality			Provides a business tax credit for certain costs incurred during carbon dioxide sequestration and capture.
MI	Draft Bill	Department of Environmental Quality	Pore space owned by surface owner.	Operator is liable during operation; state assumes liability upon issuance of Certificate of Completion.	Carbon Dioxide Storage Facility Trust Fund
MI	SB 775 (2009) Pending	Department of Environmental Quality	CO_2 ownership begins with operator and transfers to state 10 years after Notice of Completion.	Operator is liable during operation; state assumes liability 10 years after Notice of Completion.	Carbon Dioxide Storage Facility Trust Fund
MN	HB 1669 (2011) Pending	The State of Minnesota			The state is reserving credits for CCS in current or future state lands.
MN	SF 145 (2007) Enacted Ch. 136				Incentives for IGCC.
MS	SB 2723 (2011) Enacted 53-11-1	State Oil and Gas Board	At least a majority interest in the property rights is required. Sequestration wells, buildings and equipment utilized in geologic sequestration are owned by the storage operator, which includes pipelines. The owner of the carbon dioxide shall have no right to gas, liquid hydrocarbons, salt, or other commercial minerals.	To the Owner(s)	Carbon Dioxide Storage Fund
MS	HB 1459 (2009) Enacted 27-65-19				Income tax of 1.5% on businesses that sell CO_2 for EOR or sequestration.
MT	SB 285 (2011) Enacted 82-11-183	Board of Oil and Gas Conservation in consultation with the Department of Environmental Quality and the Department of Natural Resources and Conservation	The geologic storage operator has title to the geologic storage reservoir and may transfer title of the reservoir and the stored carbon dioxide to the state.	If the title is not transferred to the state, then the Operator accepts liability.	
MT	SB 498 (2009) Enacted	Board of Oil and Gas Conservatory with comments from Department of Environmental Quality	Pore space owned by surface owner. CO_2 owned by operator.	Operator is liable during operation; state assumes long term liability.	
MT	HB 3 (2007) Enacted				Tax incentives for gasification plants that sequester CO_2.
ND	SB 2318 (2011) Enacted	Legislative Management			Legislative Management will look to the possibility of CO_2 storage easements.
ND	SB 2034 (2009) Enacted 57-51.1-03				Tax incentives for Enhanced Oil Recovery (EOR) with CO_2.
ND	SB 2095 (2009) Enacted 38-22 Repealed 38-08-24	Industrial Commission	CO_2 owned by operator.	Operator is liable during operation; state assumes long term liability.	
ND	SB 2139 (2009) Enacted		Pore space owned by surface owner; severance prohibited.		
ND	SB 2221 (2009) Enacted 57-60-01; 57-60-02.1 Amended 57-60-03				Tax incentives for coal plants that capture CO_2.
NM	SB 994 (2007) Enacted Ch.229				Incentives for energy facilities to capture and sequester CO_2.

State	Bill (year)	Project Authority	Pore Space/CO_2 Ownership	Liability	Financing Source
NY	A03182 (2010) Pending	Administered by the Department of Environmental Conservation (DEC)	The operator has ownership of the CO_2 and the landowners have ownership of the pore space.	Default liability is to the Operator unless contracted to the owner.	Relates to a pilot program to enable the capture and storage of carbon dioxide and establishes the carbon capture and sequestration act. This bill would have no significant fiscal impacts on the state.
NY	A05836 (2010) Pending	NY Department of Environmental Conservation	Pore space owned by surface estate owner.	Operator is liable during operation; state assumes long term liability after 10 years.	
NY	A08802 (2010) Pending	NY Department of Environmental Conservation	Pore space owned by surface owner. CO_2 owned by operator.		
NY	Advanced Clean Coal Power Plant Initiative (2006)				Incentive program for advanced coal plants with sequestration.
OK	SB 2024 (2010) Pending	Corporation Commission			
OK	SB 610 (2009) Enacted	Corporation Commission for fossil fuel bearing formations; Department of Environmental Quality for all others	CO_2 owned by operator. Does not alter the incidents of ownership, or other rights, of the owners of the mineral estate or adversely affect enhanced oil or gas recovery efforts in the state. Prohibits the use of eminent domain to be used by a private operator.		The Petroleum Storage Tank Release Environmental Cleanup Indemnity Fund and Program and the Leaking Underground Storage Tank Trust Fund. State water/wastewater loans and grants, revolving fund, and other related financial aid programs including federal funding.
PA	HB 2405 (2010) Pending	Pennsylvania Public Utility Commission	CCS facility owns the Co_2 once transferred. State will allow the lease of state lands for CO_2 pipelines.	CCS facilities receive liability of CO_2, once transferred, and the coal combustion plant will become immune. Operators of CCS facilities have the same rights and subject to the same penalties as the Solid waste Management Act, but Administrative penalties cannot exceed $50,000. Upon Closure of a CCS facility, liability is transferred to the state.	Carbon Dioxide Indemnification Fund
TX	HB 1796 (2009) Enacted Ch. 382	General Land Office and the Bureau of Economic Geology to build and operate a carbon dioxide repository on state-owned, offshore, submerged land.	CO_2 owned by state for offshore sequestration.	School Land Board is liable during operation for offshore sequestration, but liability is not relieved from a producer of CO_2 prior to it being stored.	Permanent School Fund, state grants
TX	SB 1387 (2009) Enacted Section 27.002	Railroad Commission has jurisdiction over the injection of CO_2 into wells for production of oil or gas.	CO_2 owned by operator, unless otherwise agreed.		Anthropogenic Carbon Dioxide Storage Trust Fund
TX	HB 469 (2009) Enacted Ch. 490	Comptroller			Tax incentive for energy projects that capture and sequester CO_2
TX	HB 3732 (2007) Enacted Ch. 447	State Energy Conservation Office			Incentives for advanced energy projects, including advanced coal, such as "The advanced clean energy project grant and loan program."

State	Bill (year)	Project Authority	Pore Space/CO_2 Ownership	Liability	Financing Source
VA	SB 247 (2010) pending	Department of Mines, Minerals and Energy	CO_2 owned by operator, transfer to Commonwealth upon issuance of Certificate of Project Completeness.	Operator liable during operation. Transfers to Commonwealth upon issuance of Certificate of Project Completeness.	Carbon Dioxide Storage Facility Trust Fund
VA	SB 1416/HB 3068 (2007) Enacted Ch.933	State Corporation Commission (SCC)			Incentives for advanced coal plants
WA	SB 6001 (2007) Partially Vetoed Ch. 307	Department of Ecology			
WV	HB 2860/SB 396 (2009) Enacted Ch. 97	Department of Environmental Protection	Will be determined by recommendations from the CCS working group	Civil liability exists for any loss of fish or any other aquatic life.	
WY	HB 17 (2010) Enacted Ch. 52	Water Quality Division of the Department of Environmental Quality		Requires liability insurance policies for geologic sequestration site permittees.	Wyoming geologic sequestration special revenue account, funded by monies collected from entities permitted to operate geologic sequestration sites in Wyoming. Appropriates $200,000 to fund the reclassification of a position within DEQ to help with the rule making and financial assurance duties imposed by this legislation
WY	HB 58 (2009) Enacted Ch. 50		CO_2 owned by operator.	Operator liable during operation. No person is liable for the consequences of injecting carbon dioxide simply because they own the pore space, have the ability to control the pore space or have given consent to the injection.	
WY	SB 1 (2008) Enacted Ch. 48				Funding for sequestration site evaluation and advancement of clean coal and carbon management activities ($1.2 million)
WY	HB 90 (2008) Enacted Ch. 30	Department of Environmental Quality			$250,000 given to the working group for related expenses such as permitting.
WY	HB 89 (2008) Enacted Ch. 29		Owner of the surface estate owns the pore space in all strata below the surface. Pore space owned by surface owner, may be severed.	Legal requirements for notice to real property owners are not required for pore space owners unless the law specifically identifies those owners as being required to be notified.	

The appropriate citation is American Carbon Registry (2015), *Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects,* Version 1.0. Winrock International, Little Rock, Arkansas.

American Carbon Registry
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METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

CAPTURING AND DESTROYING METHANE FROM COAL AND TRONA MINES IN NORTH AMERICA

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

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ACRONYMS

For purposes of this methodology, the following acronyms apply:

AAPG	American Association of Petroleum Geologists
acf	Actual cubic feet
acfm	Actual cubic feet per minute
ACR	American Carbon Registry
AMM	Abandoned Mine Methane
ASTM	American Society of Testing and Materials
atm	Atmosphere in reference to a unit of pressure
Btu	British thermal unit
CBM	Coalbed Methane
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
d	Day
F	Fahrenheit
GHG	Greenhouse gas
GWP	Global Warming Potential
h	Hour
kg	Kilogram
lb	Pound
m	Minute

MG	Mine Gas
MM	Mine Methane
MMBtu	Million British thermal units
MMC	Mine Methane Capture
Mscf	Thousand standard cubic feet
Mscf/d	Thousand standard cubic feet per day
MSHA	Mine Safety and Health Administration
MT	Metric Ton
MWh	Megawatt hour
N_2O	Nitrous Oxide
R	Rankine
scf	Standard cubic foot
scf/d	Standard cubic feet per day
scfm	Standard cubic feet per minute
SMM	Surface Mine Methane
SSR	GHG sources, sinks, and reservoirs
STP	Standard temperature and pressure
QA/QC	Quality Assurance and Quality Control
VA	Ventilation Air
VAM	Ventilation Air Methane

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1 PURPOSE

The purpose of the methodology is to quantify greenhouse gas emission reductions associated with the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations at active underground and surface coal and trona mines and abandoned underground coal mines.

Mine methane refers to methane released from coal or trona and surrounding rock during mining activities, which poses a safety hazard to mine workers and must be managed through engineering controls. In addition, methane continues to desorb from coal and be emitted to the atmosphere long after mines are abandoned. The U.S. Environmental Protection Agency estimates that coal mine methane emissions contribute 9% of global anthropogenic methane emissions.

Mine methane is emitted to the atmosphere from five sources:

1. Ventilation air systems at underground mines
2. Degasification systems at underground mines
3. Earthmoving activities that expose coal at surface mines
4. Abandoned underground mines
5. Fugitive emissions from post-mining transportation, storage, and handling of coal

The methodology addresses mine methane emission reductions from sources 1-4 above, which use a number of technologies readily available to use or destroy methane from active and abandoned mines. The methodology describes separate eligibility requirements and quantification methods for each of the four methane sources – ventilation air methane from underground mines, and drainage gas from underground mines, surface mines, and abandoned mines. Also, the methodology is designed to allow projects to combine methane sources 1 and 2.

2 ELIGIBLE ACTIVITIES – QUANTIFICATION METHODOLOGY

This methodology includes four mine methane capture activities designed to reduce GHG emissions that result from the mining process at active underground mines, active surface mines, and abandoned underground mines. The following types of mine methane capture activities are eligible:

2.1 ACTIVE UNDERGROUND MINE VENTILATION AIR METHANE ACTIVITIES

This methodology applies to MMC projects that install a VAM collection system and a qualifying device to destroy the methane in VA that would otherwise be vented into the atmosphere through the return air shaft(s) as a result of underground coal or trona mining operations.

I. Methane sources eligible for VAM activities include:
   A. Ventilation systems; and
   B. Methane drainage systems from which mine gas is extracted and used to supplement VA. Only the mine methane sent with ventilation air to a destruction device is eligible.

II. In order to be considered a qualifying device for the purpose of this methodology, the device must not have been operational at the mine prior to the project start date unless it was used in a past project located at the mine and was a qualifying device in that project.

III. At active underground mines, a Project Proponent may operate both VAM and methane drainage activities as a single offset project. The mine methane capture and destruction activity that began first shall be used to determine the project start date, per the requirements of Section 3.5. Alternatively, the Project Proponent may elect to operate separate offset projects for each activity with unique start dates.

IV. If a newly constructed ventilation shaft is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or list the addition as a new MMC project.

V. If an existing ventilation shaft that was not connected to a destruction device at time of the project start date is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or as a new MMC project.

VI. If a new qualifying destruction device is added to a ventilation shaft currently connected to an existing qualifying destruction device this addition of the new qualifying destruction device is considered an offset project expansion.

2.2 ACTIVE UNDERGROUND MINE METHANE DRAINAGE ACTIVITIES

This methodology applies to MMC projects that install equipment to capture and destroy methane extracted through a methane drainage system that would otherwise be vented into the atmosphere as a result of underground coal or trona mining operations.

I. Methane drainage systems must consist of one, or a combination of, the following methane sources that drain methane from the mineral seam, surrounding strata, or underground workings of the mine before, during, and/or after mining:
   A. Pre-mining surface wells; and
   B. In-mine boreholes and post-mining wells.
II. In order to be considered a qualifying device for the purpose of this methodology, a methane destruction device for an active underground mine methane drainage activity must not have been operational at the mine prior to the project start date unless it was used in a past project located at the mine and was a qualifying device in that project.
III. At active underground mines, a Project Proponent may operate both VAM and methane drainage activities as a single project. The mine methane capture and destruction activity that began first shall be used to determine the project start date, per the requirements of Section 3.5. Alternatively, the Project Proponent may elect to operate separate projects for each activity with unique start dates.
IV. If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or a new MMC project.
V. If an existing well/borehole that was not connected to a destruction device at the project start date is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or a new MMC project.
VI. If a new qualifying destruction device is connected to a well/borehole currently connected to an existing qualifying destruction device, this addition of the new qualifying destruction device is considered an offset project expansion.
VII. Mine methane from any well or borehole connected to a pre-project destruction device at any point during the 24 months prior to the project start date is not eligible for crediting.
VIII. To be eligible for crediting under this methodology, MMC projects at active underground mines must not:

A. Account for virgin CBM extracted from coal seams outside the extents of the mine according to the mine plan or from outside the methane source boundaries as described in Section 3.4; or
B. Use CO_2, steam, or any other fluid/gas to enhance mine methane drainage.

2.3 ACTIVE SURFACE MINE METHANE DRAINAGE ACTIVITIES

This methodology applies to MMC projects that install equipment to capture and destroy methane extracted through a methane drainage system that would otherwise be vented into the atmosphere as a result of surface coal or trona mining operations.

I. Methane drainage systems must consist of one, or a combination, of the following methane sources that drain methane from the coal seam or surrounding strata before and/or during mining:
   A. Pre-mining surface wells;
   B. Existing CBM wells that would otherwise be shut-in and abandoned as a result of encroaching mining;
   C. Abandoned wells that are reactivated; and
   D. Converted dewatering wells.
II. In order to be considered a qualifying device for the purpose of this methodology, a methane destruction device for an active surface mine methane drainage activity must not have been operational at the mine prior to the project start date unless it was used in a past project located at the mine and was a qualifying device in that project.
III. If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or a new MMC project.
IV. If an existing well/borehole that was not connected to a destruction device at time of the project start date is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or a new MMC project.
V. If a new qualifying destruction device is connected to a well/borehole currently connected to an existing qualifying destruction device, this addition of the new qualifying destruction device is considered an offset project expansion.
VI. To be eligible for crediting under this methodology, MMC projects at active surface mines must not:
   A. Account for CBM produced from wells outside the extents of the mine according to the mine plan or from outside the methane source boundaries as described in Section 3.4;

B. Use CO_2, steam, or any other fluid/gas to enhance mine methane drainage; or

2.4 ABANDONED UNDERGROUND MINE METHANE RECOVERY ACTIVITIES

This methodology applies to MMC projects that install equipment to capture and destroy methane extracted through a methane drainage system that would otherwise be vented into the atmosphere as a result of previous underground coal mining operations.

I. Methane drainage systems must consist of only one methane source:
   A. In-mine boreholes and post-mining wells drilled into the mine during or after mining operations[1];
II. In order to be considered a qualifying device for the purpose of this methodology, a methane destruction device for an abandoned underground mine methane recovery activity must not have been operational at the mine prior to the project start date unless the mine was previously engaged in active underground methane drainage activities and the methane destruction device was considered a qualifying destruction device for those activities or unless it was used in a past project located at the mine and was a qualifying device in that project.
III. Abandoned underground mine methane recovery activities at multiple mines with multiple mine operators may be included in a single project if they meet the following criteria:
   A. A single Project Proponent is identified and emission reductions achieved by the project will be credited to that Project Proponent.
   B. The Project Proponent meets all monitoring and verification requirements in chapters 6, and 7.
   C. Offset project activities at all abandoned mines are in compliance with laws and regulations.
IV. In the event that there are vertically separated mines overlying and underlying other mines, wells completed in one mine can be used to capture methane in overlying or underlying mines provided the wells are within the maximum vertical extent of each mine per Section 3.4(III)(D)(i).
V. If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or a new MMC project.

[1] Please note that in this methodology, in-mine boreholes and post-mining wells, are considered to be the same “methane source”. Projects may include one or more in-mine boreholes and post-mining wells within a project.

VI. If an existing well/borehole that was not connected to a destruction device at the project start date is connected to an existing or new qualifying destruction device after the project start date, the Project Proponent may either classify it as an offset project expansion or a new MMC project.

VII. If a new qualifying destruction device is connected to a well/borehole currently connected to an existing qualifying destruction device, this addition of the new qualifying destruction device is considered an offset project expansion.

VIII. AMM from any well or borehole connected to a pre-project destruction device at any point during the 24 months prior to the project start date is not eligible for crediting.

IX. To be eligible for crediting under this methodology, MMC projects at abandoned underground mines must not:

A. Account for CBM production from wells outside the extents of the mine according to the final mine map(s) or from outside the methane source boundaries described in Section 3.4;

B. Use CO_2, steam, or any other fluid/gas to enhance mine methane drainage; or

C. Voluntarily pump water from the mine for the sole purpose of extracting methane.

3 ELIGIBILITY

MMC offset projects must adhere to the eligibility requirements below as well as general ACR program requirements included in the ACR Standard.

3.1 GENERAL ELIGIBILITY REQUIREMENTS

I. Offset projects that use this methodology must:
   A. Involve the installation and operation of a device, or set of devices, associated with the capture and destruction of mine methane;
   B. Capture mine methane that would otherwise be emitted to the atmosphere; and
   C. Destroy the captured mine methane through an eligible end-use management option per Section 3.4.

II. Project Proponents that use this methodology must:
   A. Monitor SSRs within the offset project boundary as delineated in chapter 4 per the requirements of chapter 6;
   B. Quantify GHG emission reductions per chapter 5;
   C. Prepare and submit a GHG project plan in accordance with ACR Standard requirements; and
   D. Obtain validation and verification services from an ACR-approved validation and verification body.

3.2 LOCATION

I. Projects located in North America are eligible under this methodology.
II. Projects must take place at either:
   A. An active underground or surface mine permitted for coal or trona mining by an appropriate state, provincial, or federal agency and classified by MSHA or other applicable state, provincial, or federal agency as active, intermittent, non-producing or temporarily idle;
   B. An abandoned underground coal mine classified by MSHA or other applicable state, provincial, or federal agency as abandoned.
III. Mines located on federal lands are eligible for implementation of MMC projects.

3.3 ADDITIONALITY

Offset projects must meet the additionality requirements included below. Eligible offsets must be generated by projects that yield additional GHG reductions that exceed any GHG reductions otherwise required by law or regulation or any GHG reduction that would otherwise occur in a conservative business-as-usual scenario. These requirements are assessed through the Legal Requirement Test in Section 3.3.1 and the Performance Standard Evaluation in Section 3.3.2.

3.3.1 Legal Requirement Test

I. Emission reductions achieved by an MMC project must exceed those required by any law, regulation, or legally binding mandate.

II. The following legal requirement test applies to all MMC projects:

   A. If no law, regulation, or legally binding mandate exists requiring the destruction of methane at the mine at which the project is located, all emission reductions resulting from the capture and destruction of mine methane are considered to not be legally required, and therefore eligible for crediting under this methodology.

   B. If any law, regulation, or legally binding mandate exists requiring the destruction of methane at the mine at which the project is located, only emission reductions resulting from the capture and destruction of mine methane which exceeds the mandated requirement to comply with those laws, regulations, and/or legally binding mandates are eligible for crediting under this methodology.

3.3.2 Performance Standard Evaluation

I. Emission reductions achieved by an MMC project must exceed those likely to occur in a conservative business-as-usual scenario.

II. The performance standard evaluation is satisfied if the following requirements are met, on the basis of activity type:

   A. Active Underground Mine VAM Activities

      i. Destruction of VAM automatically satisfies the performance standard evaluation because destruction of VAM is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this methodology.

   B. Active Underground Mine Methane Drainage Activities

      i. Destruction of extracted mine methane automatically satisfies the performance standard evaluation because it is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this methodology.

   C. Active Surface Mine Methane Drainage Activities

i. Destruction of extracted mine methane automatically satisfies the performance standard evaluation because it is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this methodology.

D. Abandoned Underground Mine Methane Recovery Activities

i. Destruction of extracted mine methane automatically satisfies the performance standard evaluation because it is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this methodology.

3.4 METHANE SOURCE BOUNDARIES

I. Methane that would otherwise be emitted into the atmosphere during the normal course of mining activities or as a result of past mining activities is eligible under this methodology.

II. Methane from a mine's ventilation and gas drainage systems must be collected from within the mine extents according to an up-to-date or final mine plan.

III. Additional physical boundaries on the basis of activity type are as follows:

A. Active underground mine ventilation air methane activities may account for:

i. Methane contained in VA collected from a mine ventilation system; and

ii. Mine methane contained in mine gas extracted from a methane drainage system used to supplement VA.

B. To ensure that virgin coalbed methane is excluded from the mine methane accounted for in this methodology, physical boundaries must be placed on methane drainage systems. Active underground mine methane drainage activities may account for:

i. Mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mined seam through pre-mining surface wells and in-mine boreholes; and

ii. Mine methane contained in mine gas extracted through post-mining wells.

C. Active surface mine methane drainage activities may account for surface mine methane contained in mine gas extracted from all strata above and up to 50 meters below a mined seam through pre-mining surface wells, existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining, abandoned wells that are reactivated, and converted dewatering wells.

D. Abandoned underground mine methane recovery activities may account for:

i. Abandoned mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mined seam through existing or newly drilled in-mine boreholes or post-mining wells.

3.5 START DATE

I. An offset project must meet the start date requirements set forth in the ACR Standard.

II. For this methodology, the project start date is defined as the date on which the project's mine methane capture and destruction equipment becomes operational following a start-up period.

3.6 PROJECT CREDITING PERIOD

I. The crediting period for this methodology is ten years.

II. The crediting period begins on the project start date[2].

3.7 REGULATORY COMPLIANCE

I. An offset project must meet the regulatory compliance requirements set forth in the ACR Standard[3].

[2] As an exception, projects located at active underground mines that become abandoned (and therefore will reclassify an existing, operational project as an "abandoned underground mine methane project") shall designate a start date for abandoned underground mine methane project activities no later than 9 months following the date of mine abandonment. The date of mine abandonment shall be determined through MSHA or other state, provincial, or federal regulatory body documentation establishing the date on which the mine became abandoned.

[3] Note that ventilation air methane projects are not typically considered to be part of a mine ventilation plan and, therefore, are not typically subject to MSHA jurisdiction.

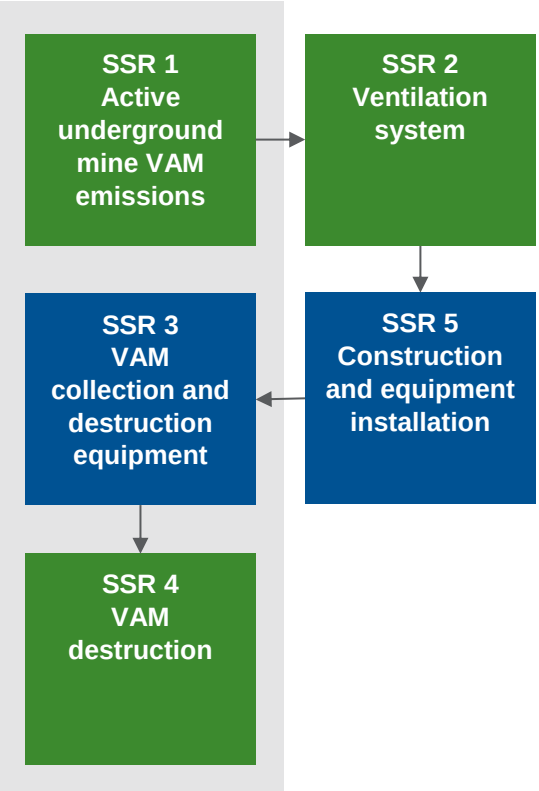
4 OFFSET PROJECT BOUNDARY – QUANTIFICATION METHODOLOGY

The offset project boundary delineates the SSRs that must be included or excluded when quantifying the net change in emissions associated with the installation and operation of a device, or set of devices, associated with the capture and destruction of mine methane. The following offset project boundaries apply to all MMC projects on the basis of activity type:

4.1 ACTIVE UNDERGROUND MINE VAM ACTIVITIES

I. Figure 1 illustrates the offset project boundary for active underground mine VAM activities, indicating which SSRs are included or excluded from the offset project boundary.
   A. All SSRs inside the grey box are included and must be accounted for under this methodology.
   B. SSRs in green boxes are relevant to the baseline and project emissions.
   C. SSRs in blue boxes are relevant only to project emissions.

Figure 1: Offset Project Boundary for Active Underground Mine VAM Activities



II. Table 1 lists the SSRs for active underground mine VAM activities, indicating which gases are included or excluded from the offset project boundary.

Table 1: Greenhouse Gas Sinks, Sources, and Reservoirs for Active Underground Mine VAM Activities

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
1 Active under-ground mine VAM emissions	Emissions from the venting of VAM through mine venti-lation system	CH_4	B, P	Included
		CO_2	n/a	Excluded

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
2 Ventilation system	Emissions resulting from energy consumed to operate mine ventilation system	CH_4	n/a	Excluded
		N_2O	n/a	Excluded
3 VAM collection and destruction equipment	Emissions resulting from energy consumed to operate additional equipment used to capture or destroy VAM	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
4 VAM destruction	Emissions resulting from VAM destruction	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions of uncombusted methane	CH_4	B, P	Included
5 Construction and equipment installation	Emissions from construction and/or installation of new equipment	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from construction	CH_4	n/a	Excluded

4.2 ACTIVE UNDERGROUND MINE METHANE DRAINAGE ACTIVITIES

I. Figure 2 illustrates the offset project boundary for active underground mine methane drainage activities, indicating which SSRs are included or excluded from the offset project boundary.

A. All SSRs inside the grey box are included and must be accounted for under this methodology.

B. SSRs in green boxes are relevant to the baseline and project emissions.

C. SSRs in blue boxes are relevant only to project emissions.

Figure 2: Offset Project Boundary for Active Underground Mine Methane Drainage Activities



II. Table 2 lists the identified SSRs for active underground mine methane drainage activities, indicating which gases are included or excluded from the offset project boundary.

Table 2: Identified Greenhouse Gas Sinks, Sources, and Reservoirs for Active Underground Mine Methane Drainage Activities

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
1 Active underground mine VAM emissions	Emissions from the venting of mine methane extracted through methane drainage system	CH_4	B, P	Included
2 Mine gas collection and destruction equipment	Emissions resulting from energy consumed to operate additional equipment used to capture, treat, or destroy drained mine gas	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of additional equipment used to capture, treat, or destroy drained mine gas	CH_4	n/a	Excluded
3 Transportation of mine gas	Emissions resulting from additional energy consumed to transport mine gas to treatment or destruction equipment	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from the on-site transportation of mine gas	CH_4	n/a	Excluded
4 Liquefaction, compression and storage of CNG/LNG	Emissions resulting from energy consumed to operate additional equipment used to liquefy, compress,	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
	or store methane for vehicle use.			
	Fugitive emissions from operation of additional equipment used to liquefy, compress, or store methane for vehicle use	CH_4	n/a	Excluded
5 Vehicle operation	Emissions resulting from mine methane combustion during vehicle operation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during vehicle operation	CH_4	B, P	Included
6 On-site electricity generation	Emissions resulting from mine methane combustion during on-site electricity generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during on-site electricity generation	CH_4	B, P	Included
7 On-site thermal energy generation	Emissions resulting from mine methane combustion during on-site thermal energy generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during on-site thermal energy generation	CH_4	B, P	Included
8 On-site flaring		CO_2	B, P	Included

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
	Emissions resulting from mine methane combustion during on-site flaring	N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during flaring	CH_4	B, P	Included
9 Pipeline injection	Emissions resulting from mine methane combustion resulting from pipeline injection	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from the incomplete mine methane combustion resulting from pipeline injection	CH_4	B, P	Included
10 Well drilling and gas well completion	Emissions from well drilling and gas well completion	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from well drilling and gas well completion	CH_4	n/a	Excluded
11 Displacement of fossil fuels or electricity	Emission reductions resulting from the displacement of fossil fuels or electricity	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

4.3 ACTIVE SURFACE MINE METHANE DRAINAGE ACTIVITIES

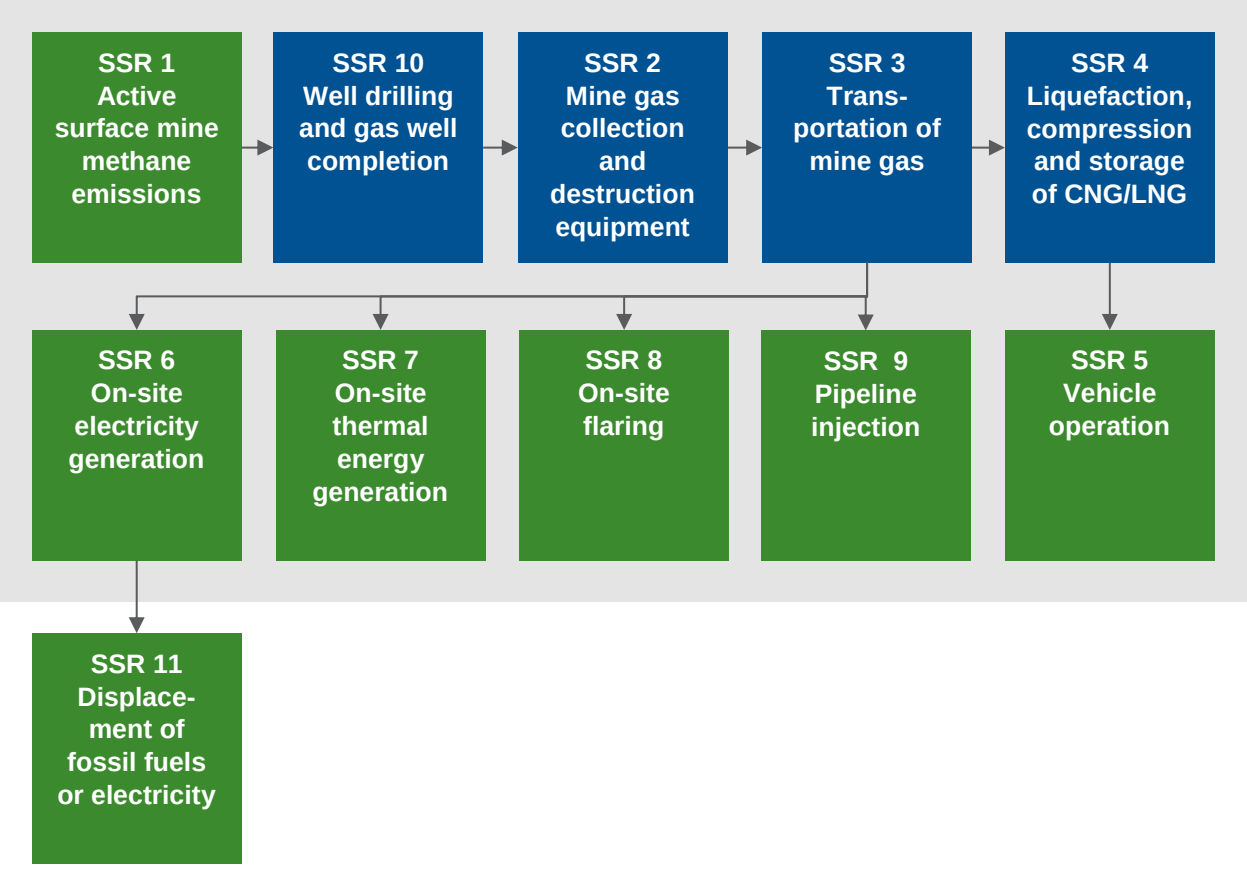
I. Figure 3 illustrates the offset project boundary for active surface mine methane drainage activities, indicating which SSRs are included or excluded from the offset project boundary.

A. All SSRs inside the grey box are included and must be accounted for under this methodology.

B. SSRs in green boxes are relevant to the baseline and project emissions.

C. SSRs in blue boxes are relevant only to project emissions.

Figure 3: Offset Project Boundary for Active Surface Mine Methane Drainage Activities



II. Table 3 lists the SSRs for active surface mine methane drainage activities, indicating which gases are included or excluded from the offset project boundary.

Table 3: Greenhouse Gas Sinks, Sources, and Reservoirs for Active Surface Mine Methane Drainage Activities

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
1 Active surface mine methane emissions	Emissions from the venting of mine methane during the mining process	CH_4	B, P	Included
2 Mine gas collection and destruction equipment	Emissions resulting from energy consumed to operate additional equipment used to capture, treat, or destroy drained mine gas	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of additional equipment used to capture, treat, or destroy drained mine gas	CH_4	n/a	Excluded
3 Transportation of mine gas	Emissions resulting from additional energy consumed to transport mine gas to treatment or destruction equipment	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from the on-site transportation of mine gas	CH_4	n/a	Excluded
4 Liquefaction, compression and storage of CNG/LNG	Emissions resulting from energy consumed to operate additional equipment used to liquefy, compress,	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
	or store methane for vehicle use.			
	Fugitive emissions from operation of additional equipment used to liquefy, compress, or store methane for vehicle use	CH_4	n/a	Excluded
5 Vehicle operation	Emissions resulting from mine methane combustion during vehicle operation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during vehicle operation	CH_4	B, P	Included
6 On-site electricity generation	Emissions resulting from mine methane combustion during on-site electricity generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during on-site electricity generation	CH_4	B, P	Included
7 On-site thermal energy generation	Emissions resulting from mine methane combustion during on-site thermal energy generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during on-site thermal energy generation	CH_4	B, P	Included
8 On-site flaring		CO_2	B, P	Included

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
	Emissions resulting from mine methane combustion during on-site flaring	N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during flaring	CH_4	B, P	Included
9 Pipeline injection	Emissions resulting from mine methane combustion resulting from pipeline injection	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from the incomplete mine methane combustion resulting from pipeline injection	CH_4	B, P	Included
10 Well drilling and gas well completion	Emissions from additional well drilling and well gas completion	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from additional well drilling and gas well completion	CH_4	n/a	Excluded
11 Displacement of fossil fuels or electricity	Emission reductions resulting from the displacement of fossil fuels or electricity	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

4.4 ABANDONED UNDERGROUND MINE METHANE RECOVERY ACTIVITIES

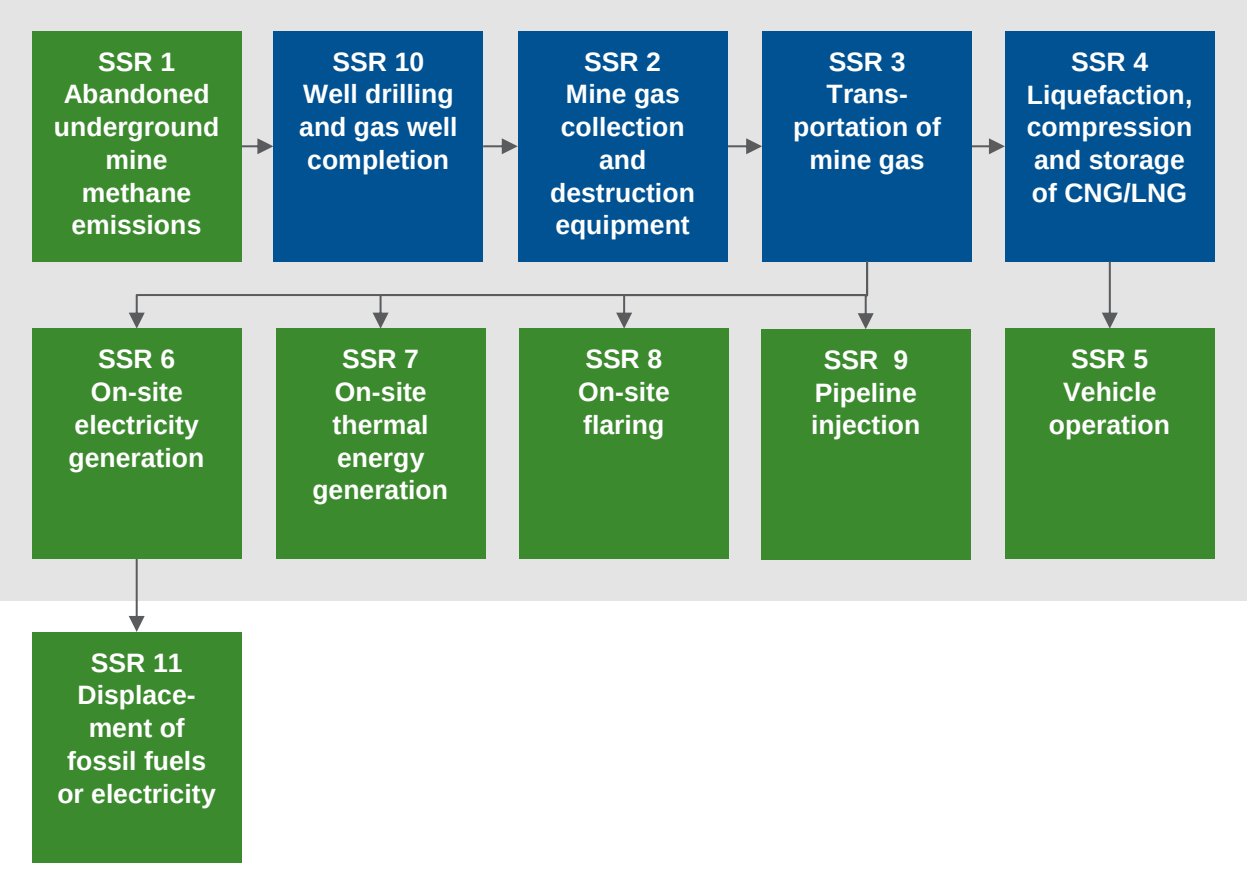
I. Figure 4 illustrates the offset project boundary for abandoned underground mine methane recovery activities, indicating which SSRs are included or excluded from the offset project boundary.

A. All SSRs inside the grey box are included and must be accounted for under this methodology.

B. SSRs in green boxes are relevant to the baseline and project emissions.

C. SSRs in blue boxes are relevant only to project emissions.

Figure 4: Offset Project Boundary for Abandoned Underground Mine Methane Recovery Activities



II. Table 4 lists the SSRs for abandoned underground mine methane recovery activities, indicating which gases are included or excluded from the offset project boundary.

Table 4: Greenhouse Gas Sinks, Sources, and Reservoirs for Abandoned Underground Mine Methane Recovery Activities

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
1 Abandoned underground mine methane emissions	Emissions of mine methane liberated after the conclusion of mining operations	CH_4	B, P	Included
2 Mine gas collection and destruction equipment	Emissions resulting from energy consumed to operate additional equipment used to capture, treat, or destroy drained mine gas	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of additional equipment used to capture, treat, or destroy drained mine gas	CH_4	n/a	Excluded
3 Transportation of mine gas	Emissions resulting from additional energy consumed to transport mine gas to treatment or destruction equipment	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from the on-site transportation of mine gas	CH_4	n/a	Excluded
		CO_2	P	Included

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
4 Liquefaction, compression and storage of CNG/LNG	Emissions resulting from energy consumed to operate equipment used to liquefy, compress, or store methane for vehicle use.	CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of equipment used to liquefy, compress, or store methane for vehicle use	CH_4	n/a	Excluded
5 Vehicle operation	Emissions resulting from mine methane combustion during vehicle operation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during vehicle operation	CH_4	B, P	Included
6 On-site electricity generation	Emissions resulting from mine methane combustion during on-site electricity generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during on-site electricity generation	CH_4	B, P	Included
7 On-site thermal energy generation	Emissions resulting from mine methane combustion during on-site thermal energy generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane	CH_4	B, P	Included

SSR	DESCRIPTION	GHG	BASELINE (B) OR PROJECT (P)	INCLUDED OR EXCLUDED
	combustion during on-site electricity generation			
8 On-site flaring	Emissions resulting from mine methane combustion during on-site flaring	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete mine methane combustion during flaring	CH_4	B, P	Included
9 Pipeline injection	Emissions resulting from mine methane combustion resulting from pipeline injection	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from the incomplete mine methane combustion resulting from pipeline injection	CH_4	B, P	Included
10 Well drilling and gas well completion	Emissions from additional well drilling and well gas completion	CO_2	B, P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from additional well drilling and gas well completion	CH_4	n/a	Excluded
11 Displacement of fossil fuels or electricity	Emission reductions resulting from the displacement of fossil fuels or electricity	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

5 QUANTIFYING GHG EMISSION REDUCTIONS – QUANTIFICATION METHODOLOGY

I. GHG emission reductions from an MMC project are quantified by comparing project emissions to baseline emissions at the mine.
II. Project Proponents must use the activity type-specific calculation methods provided in this methodology to determine baseline and project GHG emissions.
III. Measurements used to quantify GHG emission reductions must be quantified using flow rates and methane densities adjusted to standard conditions of 60°F and 14.7 pounds per square inch (1 atm).
IV. Depending on the methane analyzer technology used, methane concentration readings may or may not need to be adjusted for temperature and pressure. If readings require adjustment, then such adjustments must be performed.
V. Global warming potential values must be determined in accordance with the requirements set forth in the ACR Standard.

5.1 ACTIVE UNDERGROUND MINE VENTILATION AIR METHANE ACTIVITIES

I. GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) using Equation 1.

Equation 1: GHG Emission Reductions

$$ER = BE - PE$$

WHERE

ER	Emission reductions achieved by the project during the reporting period (MT CO_2e)
BE	Baseline emissions during the reporting period (MT CO_2e)

PE	Project emissions during the reporting period (MT CO_2e)

5.1.1 Quantifying Baseline Emissions

I. For active underground mine ventilation air methane projects, baseline emissions equal methane released into the atmosphere during the reporting period.

Equation 2: Baseline Emissions

$$BE = BE_{MR}$$

AND

$$BE_{MR} = \sum_{i} \sum_{t} BE_{MR_{i,t}}$$

WHERE

BE	Baseline emissions during the reporting period (MT CO_2e)
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)
BE_{MR}	Baseline emissions from methane captured and sent to qualifying devices for destruction that would have been released to the atmosphere in the absence of the project (MT CO_2e)
$BE_{MR_{i,t}}$	Baseline emissions from methane captured and sent to qualifying device **i** for destruction during time interval **t** that would have been released to the atmosphere in the absence of the project (MT CO_2e).

II. Baseline emissions from the release of methane ($BE_{MRi,t}$) must be quantified using Equation 3.

III. $BE_{MRi,t}$ must account for the total amount of methane captured and sent to all qualifying devices during the reporting period.

IV. VAM project activities may supplement VA with mine gas (MG) extracted from a methane drainage system to either increase or help balance the methane concentration of VA flowing into the destruction device. If MG is used to supplement VA, the MG destroyed by the project during the reporting period must be accounted for using Equation 3 as $MG_{flow,t}$.

V. Methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions since it is vented in both scenarios.

Equation 3: Baseline Emissions from Release of Methane

$$\mathbf{BE_{MR_{i,t}} = \sum_{t}\left[\left(VA_{flow_t} \times T \times C_{CH4_t}\right) + \left(MG_{flow_t} \times T \times C_{CH4,MG_t}\right)\right] \times 0.0423 \times 0.000454 \times GWP_{CH4}}$$

WHERE

$BE_{MR_{i,t}}$	Baseline emissions from methane captured and sent to qualifying device i for destruction during time interval t that would have been released to the atmosphere in the absence of the project (MT CO_2e)
VA_{flow_t}	Volume flow rate of ventilation air sent to qualifying device i for destruction during time interval t (scfm)
C_{CH4_t}	Measured methane concentration of captured ventilation air sent to qualifying device i for destruction during time interval t (scfm CH_4/scfm)
MG_{flow_t}	Volume flow rate of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying device i for destruction during time interval t (scfm)
C_{CH4,MG_t}	Measured methane concentration of captured mine gas that would have been sent with ventilation air to qualifying device i for destruction during time interval t (scfm CH_4/scfm)
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
0.0423	Standard density of methane (lb CH_4/scf CH_4)

0.000454	MT CH_4/lb CH_4
GWP_{CH4}	Global warming potential of methane (MT CO_2e/MT CH_4)

Methane concentrations and flow rate recordings must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

5.1.2 Quantifying Project Emissions

I. Project emissions must be quantified during the entire reporting period.
II. Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 1 and using Equation 4.
III. VAM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions since it is vented in both scenarios.

Equation 4: Project Emissions

$$\mathbf{PE = PE_{EC} + PE_{MD} + PE_{UM}}$$

WHERE

PE	Project emissions during the reporting period (MT CO_2e)
PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)
PE_{MD}	Project emissions from destruction of methane during the reporting period (MT CO_2e)
PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)

IV. If the project uses fossil fuel or grid electricity to power additional equipment required for project activities (e.g., capturing and destroying ventilation air, transporting ventilation air, etc.), the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 5.

Equation 5: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1,000}$$

WHERE

PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)
$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	CO_2 emission factor of electricity used from Table 10 in Appendix A (MT CO_2e/MWh)
$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{HEAT}	CO_2 emission factor of heat used from Equation 39 in Appendix A (kg CO_2/volume)
$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{FF}	CO_2 emission factor of fossil fuel used from Table 9 in Appendix A (kg CO_2/volume)
$\frac{1}{1,000}$	Conversion of kg to metric tons

V. Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equation 6.

Equation 6: Project Emissions from Destruction of Methane

$$PE_{MD} = \sum_{i} \sum_{t} PE_{MD_{i,t}}$$

AND

$$PE_{MD_{i,t}} = MD_{i,t} \times CEF_{CH4}$$

WHERE

PE_{MD}	Project emissions from destruction of methane by all qualifying devices during the reporting period (MT CO_2e)
$PE_{MD_{i,t}}$	Project emissions from destruction of methane by qualifying device i during time interval t (MT CO_2e)
$MD_{i,t}$	Methane destroyed by qualifying device i during time interval t; calculated separately for each destruction device (MT CH_4)
CEF_{CH4}	CO_2 emission factor for combusted methane (2.744 MT CO_2e/MT CH_4)
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)

VI. The amount of methane destroyed ($MD_{i,t}$) must be quantified using Equation 7.

VII. If MG is used to supplement VA, the MG destroyed by the project during the reporting period must be accounted for using Equation 7 as $MG_{flow,t}$.

VIII. If cooling air was added to the destruction device after the point of metering for VA, this must be accounted for with term $CA_{flow,t}$ in Equations 7 and 8. If no cooling air is added, then $CA_{flow,t} = 0$.

IX. If the flow rate of cooling air was metered, then the metered data flow rate must be used. If the flow rate was not metered, the maximum capacity of the cooling air intake system must be used for the flow rate.

Equation 7: Methane Destroyed

$$\mathbf{MD_{i,t} = \left(MM_{i,t} - PE_{NO_{i,t}}\right)}$$

WHERE

$MD_{i,t}$	Methane destroyed by qualifying device **i** during time interval **t**; calculated separately for each destruction device (MT CH_4)
$MM_{i,t}$	Measured methane sent to qualifying device **i** for destruction during time interval **t** (MT CH_4)
$PE_{NO_{i,t}}$	Project emissions of non-oxidized methane emitted as a result of incomplete oxidation of the ventilation air stream sent to qualifying device **i** for destruction during time interval **t** (MT CH_4)
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)

WITH

$$\mathbf{MM_{i,t} = \sum_{t}\left(VA_{flow_t} \times T \times C_{CH4_t}\right) + \left(MG_{flow_t} \times T \times C_{CH4,MG_t}\right) \times 0.0423 \times 0.000454}$$

WHERE

VA_{flow_t}	Volume flow rate of ventilation air sent to qualifying device **i** for destruction during time interval **t** (scfm)
C_{CH4_t}	Measured methane concentration of captured ventilation air sent to qualifying device **i** for destruction during time interval **t** (scfm CH_4/scfm)
MG_{flow_t}	Volume flow rate of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying device **i** for destruction during time interval **t** (scfm)
C_{CH4,MG_t}	Measured methane concentration of captured mine gas sent with ventilation air to qualifying device **i** for destruction during time interval **t** (scfm CH_4/scfm)

0.0423	Standard density of methane (lb CH_4/scf CH_4)
0.000454	MT CH_4/lb CH_4
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)

WITH

$$\mathbf{PE_{NO_{i,t}} = \sum_{t}\left[\left(VA_{flow_t} \times T\right) + \left(CA_{flow_t} \times T\right)\right] \times C_{CH4_{exhaust_t}} \times 0.0423 \times 0.000454}$$

WHERE

VA_{flow_t}	Volume flow rate of ventilation air sent to qualifying device i for destruction during time interval t (scfm)
CA_{flow_t}	Volume flow rate of cooling air sent to qualifying device i for destruction after the metering point of the ventilation air stream during time interval t (scfm)
$C_{CH4_{exhaust_t}}$	Measured methane concentration of exhaust gas emitted from qualifying device i during time interval t (scfm CH_4/scfm)
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

X. Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 8.

Equation 8: Project Emissions from Uncombusted Methane

$$\mathbf{PE_{UM}} = \sum_{\mathbf{i}} \sum_{\mathbf{t}} \left(\mathbf{PE_{NO_{i,t}}} \times \mathbf{GWP_{CH_4}} \right)$$

WHERE

PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)
$PE_{NO_{i,t}}$	Project emissions of non-oxidized methane emitted as a result of incomplete oxidation of the ventilation air stream sent to qualifying device **i** for destruction during time interval **t**; calculated separately for each destruction device per Equation 7 (MT CH_4)
GWP_{CH_4}	Global warming potential of methane (MT CO_2e/MT CH_4)
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

XI. If gas flow metering equipment provides an actual or non-standardized flow rate instead of a flow rate adjusted to standard conditions, apply Equation 41 in Appendix C to standardize the flow rate of VA entering the destruction device.

5.2 ACTIVE UNDERGROUND MINE METHANE DRAINAGE ACTIVITIES

I. GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) using Equation 9.

Equation 9: GHG Emission Reductions

$$ER = BE - PE$$

WHERE

ER	Emission reductions achieved by the project during the reporting period (MT CO_2e)
BE	Baseline emissions during the reporting period (MT CO_2e)
PE	Project emissions during the reporting period (MT CO_2e)

5.2.1 Quantifying Baseline Emissions

I. For active underground mine methane drainage projects, baseline emissions equal the methane released into the atmosphere during the reporting period.

II. BE_{MR} must account for the total amount of methane captured and sent to all qualifying devices during the reporting period.

Equation 10: Baseline Emissions

$$\mathbf{BE = BE_{MR}}$$

AND

$$\mathbf{BE_{MR} = \sum_{i}\sum_{t} BE_{MR_{i,t}}}$$

WHERE

BE	Baseline emissions during the reporting period (MT CO_2e)
BE_{MR}	Baseline emissions from methane captured and sent to qualifying destruction devices that would have been released to the atmosphere in the absence of the project (MT CO_2e)
$BE_{MR_{i,t}}$	Baseline emissions from methane captured and sent to qualifying destruction device i during time interval t that would have been released to the atmosphere in the absence of the project (MT CO_2e).
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)

III. Baseline emissions from methane that would have been released to the atmosphere but that is captured and sent to qualifying destruction devices ($BE_{MR,i,t}$) must be quantified using Equation 11.

IV. Emissions from the release of methane through a pre-mining surface well is only accounted for in the baseline during the reporting period in which the emissions would have occurred (i.e., when the well is mined through). For the purposes of this methodology, a well at an active underground mine is considered mined through when any of the following occur:

A. The working face intersects the borehole, as long as the endpoint of the borehole is not more than 50 meters below the mined coal seam;

B. The working face passes directly underneath the bottom of the borehole, as long as the endpoint of the borehole is not more than 150 meters above the mined coal seam;

C. The working face passes both underneath (not more than 150 meters below the endpoint of the borehole) and to the side of the borehole if room and pillar mining technique is employed and the endpoint of the borehole lies above a block of coal that will be left unmined as a pillar; or

D. The well produces elevated amounts of atmospheric gases (the percent concentration of nitrogen in MG increases by five compared to baseline levels). A full gas analysis using a gas chromatograph must be completed by an ISO 17025 accredited lab or a lab that has been certified by an accreditation body conformant with ISO 17025 to perform test methods appropriate for atmospheric gas content analysis. To ensure that elevated nitrogen levels are the result of a well being mined through and not the result of a leak in the well, the gas analysis must show that oxygen levels did not increase by the same proportion as the nitrogen levels.

V. If using Section 5.2.1(IV)(A), (B), or (C) to demonstrate that a well is mined through, an up-to-date mine plan must be used to identify which wells were mined through, based on the above criteria, and therefore eligible for baseline quantification in any given reporting period.

VI. If the mine plan calls for mining past rather than through a borehole, MG from that borehole extracted from within the methane source boundaries as described in Section 3.4(III)(B) is eligible for quantification in the baseline when the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum.

VII. If an MMC project at an active underground mine consists of both VAM and methane drainage activities, MG extracted from a methane drainage system ($MG_{flow,t}$) may be used to supplement VA to either increase or help balance the concentration of methane flowing into the destruction device. If MG is used to supplement VA, the MG destroyed by the project during the reporting period must be accounted for using Equation 11 as $MG_{flow,t.}$

VIII. MM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 11: Baseline Emissions from Release of Methane

$$\mathbf{BE_{MR_{i,t}}} = \sum_{t} \left[\mathbf{PSW_{flow_t}} + \left(\mathbf{IBPW_{flow_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right) - \left(\mathbf{MG_{flow_t}} \times \mathbf{T} \times \mathbf{C_{CH4_{MG,t}}}\right)\right] \times \mathbf{0.0423} \times \mathbf{0.000454} \times \mathbf{GWP_{CH4}}$$

WHERE

$BE_{MRi,t}$	Baseline emissions from methane captured and sent to qualifying device **i** for destruction during time interval **t** that would have been released to the atmosphere in the absence of the project (MT CO_2e)

PSW_{flow_t}	Volume flow rate of MG from pre-mining surface wells sent to qualifying device **i** for destruction during time interval **t**. For qualifying devices, only the eligible amount per Equation 12 in accordance with Sections 5.2.1(IV), (V), and (VI) must be quantified (scfm)
$IBPW_{flow_t}$	Volume flow rate of MG from in-mine boreholes and post-mining wells sent to qualifying device **i** for destruction during time interval **t** (scfm)
C_{CH4_t}	Measured methane concentration of mine gas sent to qualifying device **i** for destruction during time interval **t**; calculated separately for each methane source (scfm CH_4/scfm)
MG_{Flow_t}	Volume flow rate of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying device **i** for destruction during time interval **t** (scfm)
$C_{CH4_{MG,t}}$	Measured methane concentration of captured mine gas sent with ventilation air to qualifying devices for destruction during time interval **t** (scfm CH_4/scfm)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
0.0423	Standard density of methane (lb CH_4/scf CH_4)
0.000454	MT CH_4/lb CH_4
GWP_{CH4}	Global warming potential of methane (MT CO_2e/MT CH_4)

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

IX. The eligible amount of MG from pre-mining surface wells destroyed by qualifying devices (PSW_{flow_t}) must be determined by using Equation 12.

Equation 12: Eligible MG from Pre-mining Surface Boreholes

$$\mathbf{PSW_{flow_t}} = \sum_{t} \left(\mathbf{PSW_{pre_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right) + \left(\mathbf{PSW_{post_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right)$$

WHERE

PSW_{flow_t}	Volume flow rate of MG from pre-mining surface wells sent to qualifying device i for destruction during time interval t that is eligible for quantification in the reporting period for use in Equation 11 (scfm)
PSW_{pre_t}	Volume flow rate of MG sent to qualifying device i for destruction during time interval t, from the beginning of the crediting period through the end of the reporting period, captured from pre-mining surface wells that were mined through during the reporting period (scfm)
PSW_{post_t}	Volume flow rate of MG sent to qualifying device i for destruction during time interval t in the reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods (scfm)
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
C_{CH4_t}	Measured methane concentration of mine gas sent to qualifying device i for destruction during time interval t; calculated separately for each methane source (scfm CH_4/scfm)

5.2.2 Quantifying Project Emissions

I. Project emissions must be quantified during the entire reporting period.
II. Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 2 and using Equation 13.
III. Mine methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions since it is vented in both scenarios.

Equation 13: Project Emissions

$$\mathbf{PE} = \mathbf{PE_{EC}} + \mathbf{PE_{MD}} + \mathbf{PE_{UM}}$$

WHERE

PE	Project emissions during the reporting period (MT CO_2e)
PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)
PE_{MD}	Project emissions from destruction of methane during the reporting period (MT CO_2e)
PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)

IV. If the project uses fossil fuel or grid electricity to power additional equipment required for project activities (e.g., capturing and destroying mine gas, transporting mine gas, etc.), the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 14.

V. If the total electricity generated by project activities is greater than the additional electricity consumed for the capture and destruction of methane, then $CONS_{ELEC} = 0$ in Equation 14.

Equation 14: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$\mathbf{PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1,000}}$$

WHERE

PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)
$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	CO_2 emission factor of electricity used from Table 10 in Appendix A (MT CO_2e/MWh)
$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)

CEF_{HEAT}	CO_2 emission factor of heat used from Equation 39 (kg CO_2/volume)
$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{FF}	CO_2 emission factor of fossil fuel used from Table 9 in Appendix A (kg CO_2/volume)
$\frac{1}{1{,}000}$	Conversion of kg to metric tons

VI. Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equation 15.

VII. Project emissions for pre-mining surface wells that are mined through during the reporting period must include the CO_2 emissions resulting from the destruction of all MG from the mined-through wells that took place during and prior to the reporting period.

Equation 15: Project Emissions from Destruction of Captured Methane

$$\mathbf{PE_{MD}} = \sum_{\mathbf{i}} \sum_{\mathbf{t}} \mathbf{PE_{MD_{i,t}}}$$

AND

$$\mathbf{PE_{MD_{i,t}}} = \mathbf{MD_{i,t}} \times \mathbf{CEF_{CH4}}$$

WHERE

PE_{MD}	Project emissions from destruction of methane by all qualifying devices during the reporting period (MT CO_2e)
$PE_{MD_{i,t}}$	Project emissions from destruction of methane by qualifying destruction device i during time interval t (MT CO_2e)
$MD_{i,t}$	Methane destroyed by qualifying device i during time interval t; calculated separately for each destruction device (MT CH_4)
CEF_{CH4}	CO_2 emission factor for combusted methane (2.744 MT CO_2e/MT CH_4)

i	Use of methane (oxidation or alternative end-use) by all qualifying destruction devices
t	Time interval (not exceeding 15 minutes)

VIII. The amount of methane destroyed ($MD_{i,t}$) must be quantified using Equation 16.

Equation 16: Methane Destroyed

$$\mathbf{MD_{i,t} = \left(MM_{i,t} \times DE_i\right)}$$

WHERE

$MD_{i,t}$	Methane destroyed through use **i** by qualifying devices during time interval **t**; calculated separately for each destruction device (MT CH_4)
$MM_{i,t}$	Measured methane sent to qualifying devices for destruction through use **i** during time interval **t** (MT CH_4)
DE_i	Efficiency of methane destruction device **i**, either site-specific or from Table 12 in Appendix B (decimal)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)

WITH

$$\mathbf{MM_{i,t} = \sum_t \left[PSW_{flow_t} + \left(IBPW_{flow_t} \times T \times C_{CH4,t}\right) - \left(MG_{flow_t} \times T \times C_{CH4_{MG,t}}\right)\right] \times 0.0423 \times 0.000454}$$

WHERE

$MM_{i,t}$	Measured methane sent to qualifying devices for destruction through use **i** during time interval **t** (MT CH_4)

PSW_{flow_t}	Volume flow rate of MG from pre-mining surface wells sent to qualifying device **i** for destruction during time interval **t** that is eligible for quantification in the reporting period quantified per Equation 12 (scfm)
$IBPW_{flow_t}$	Volume flow rate of MG from in-mine boreholes and post-mining wells sent to qualifying device **i** for destruction during time interval **t** (scfm)
$C_{CH4,t}$	Measured methane concentration of mine gas sent to qualifying devices for destruction during time interval **t**; calculated separately for each methane source (scfm CH_4/scfm)
MG_{flow_t}	Volume flow rate of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying device **i** for destruction during time interval **t** (scfm)
$C_{CH4\,MG,t}$	Measured methane concentration of captured mine gas sent with ventilation air to qualifying devices for destruction during time interval **t** (scfm CH_4/scfm)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
0.0423	Standard density of methane (lb CH_4/scf CH_4)
0.000454	MT CH_4/lb CH_4

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

IX. Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 17.

X. Project emissions for pre-mining surface wells that are mined through during the reporting period must include the uncombusted methane portion of MG from the mined-through ells that was emitted during and prior to the reporting period.

Equation 17: Project Emissions from Uncombusted Methane

$$\mathbf{PE_{UM}} = \sum_{\mathbf{i}} \sum_{\mathbf{t}} \left[\mathbf{MM_{i,t}} \times (\mathbf{1} - \mathbf{DE_i})\right] \times \mathbf{GWP_{CH_4}}$$

WHERE

PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)
$MM_{i,t}$	Measured methane sent to qualifying device **i** during time period **t**; calculated separately for each destruction device per Equation 16 (MT CH_4)
DE_i	Efficiency of methane destruction device **i**, either site-specific or from Table 12 in Appendix B (decimal)
GWP_{CH_4}	Global warming potential of methane (MT CO_2e/MT CH_4)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline etc.) by qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

XI. If gas flow metering equipment provides an actual or non-standardized flow rate or volume instead of a flow rate or volume adjusted to standard conditions, use Equation 42 in Appendix C to standardize the amount of MG sent to each qualifying and non-qualifying device during the reporting period.

5.3 ACTIVE SURFACE MINE METHANE DRAINAGE ACTIVITIES

I. GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) using Equation 18.

Equation 18: GHG Emission Reductions

$$\mathbf{ER = BE - PE}$$

WHERE

ER	Emission reductions achieved by the project during the reporting period (MT CO_2e)
BE	Baseline emissions during the reporting period (MT CO_2e)
PE	Project emissions during the reporting period (MT CO_2e)

5.3.1 Quantifying Baseline Emissions

I. Baseline emissions for a reporting period (BE) must be estimated by summing the baseline emissions for all SSRs identified as included in the baseline in Table 3 and using Equation 19.

II. For active surface mine methane drainage projects, baseline emissions equal methane released into the atmosphere during the reporting period.

III. BE_{MR} must account for the total amount of methane captured and sent to all qualifying devices during the reporting period.

Equation 19: Baseline Emissions

$$\mathbf{BE = BE_{MR}}$$

AND

$$\mathbf{BE_{MR} = \sum_{i}\sum_{t} BE_{MR_{i,t}}}$$

WHERE

BE	Baseline emissions during the reporting period (MT CO_2e)
BE_{MR}	Total Baseline emissions from methane captured and sent to all qualifying destruction devices that would have been released to the atmosphere in the absence of the project during the Reporting Period (MT CO_2e)
$BE_{MR_{i,t}}$	Baseline emissions from methane captured and sent to qualifying device i for destruction during time interval t that would have been released to the atmosphere in the absence of the project (MT CO_2e)
i	Use of methane (oxidation or alternative end-use) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)

IV. Baseline emissions from methane that would have been released to the atmosphere but that is captured and sent to qualifying destruction devices ($BE_{MR,i,t}$) must be quantified using Equation 20.

V. Emissions from the release of methane are only accounted for in the baseline during the reporting period in which the emissions would have occurred (i.e., when the well is in communication with the mine face or mined through). For the purposes of this methodology, a well at an active surface mine is considered mined through when either of the following occurs:

   A. The well is physically bisected by surface mining activities, such as excavation of overburden, drilling and blasting, and removal of the coal; or

   B. The well is considered in communication with the mine face when it produces elevated amounts of atmospheric gases (the percent concentration of nitrogen in MG increases by five compared to baseline levels). A full gas analysis using a gas chromatograph must be completed by an ISO 17025 accredited lab or a lab that has been certified by an accreditation body conformant with ISO 17025 to perform test methods appropriate for atmospheric gas content analysis. To ensure that elevated nitrogen levels are the result of a well being mined through and not the result of a leak in the well, the gas analysis must show that oxygen levels did not increase by the same proportion as the nitrogen levels.

VI. If using Section 5.3.1(V)(A) to demonstrate that a well is mined through, an up-to-date mine plan must be used to identify which wells were mined through and therefore eligible for baseline quantification in any given reporting period.

VII. SMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 20: Baseline Emissions from Release of Methane

$$BE_{MR_{i,t}} = \sum_{t} \left[PSW_{flow_t} + ECW_{flow_t} + ARW_{flow_t} + CDW_{flow_t} \right] \times 0.0423 \times 0.000454 \times GWP_{CH4}$$

WHERE

$BE_{MR_{i,t}}$	Baseline emissions from methane captured and sent to qualifying devices for destruction that would have been released to the atmosphere in the absence of the project (MT CO_2e)
PSW_{flow_t}	Volume flow rate of MG from pre-mining surface wells sent to qualifying device i for destruction during time interval t. For qualifying devices, only the eligible amount per Equation 21 in accordance with Sections 5.3.1(V) and (VI) must be quantified (scfm)
ECW_{flow_t}	Volume flow rate of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying device i for destruction during time interval t. For qualifying devices, only the eligible amount per Equation 22 in accordance with Sections 5.3.1(V) and (VI) must be quantified (scfm)
ARW_{flow_t}	Volume flow rate of MG from abandoned wells that are reactivated sent to qualifying device i for destruction during time interval t. For qualifying devices, only the eligible amount per Equation 23 in accordance with Sections 5.3.1(V) and (VI) must be quantified (scfm)
CDW_{flow_t}	Volume flow rate of MG from converted dewatering wells sent to qualifying device i for destruction during time interval t. For qualifying devices, only the eligible amount per Equation 24 in accordance with Sections 5.3.1(V) and (VI) must be quantified (scfm)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)

0.0423	Standard density of methane (lb CH_4/scf CH_4)
0.000454	MT CH_4/lb CH_4
GWP_{CH4}	Global warming potential of methane (MT CO_2e/MT CH_4)

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

VIII. The eligible amount of MG destroyed by qualifying devices must be determined by using Equations 21, 22, 23, and 24.

Equation 21: Eligible MG from Pre-mining Surface Wells

$$\mathbf{PSW_{flow_t}} = \sum_{\mathbf{t}} \left(\mathbf{PSW_{pre_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right) + \left(\mathbf{PSW_{post_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right)$$

WHERE

PSW_{flow_t}	Volume flow rate of MG from pre-mining surface wells sent to qualifying device **i** for destruction during time interval **t** that is eligible for quantification in the reporting period for use in Equation 20 (scfm)
PSW_{pre_t}	Volume flow rate of MG sent to qualifying device **i** for destruction during time interval **t**, from the beginning of the crediting period through the end of the reporting period, captured from pre-mining surface wells that were mined through during the reporting period (scfm)
PSW_{post_t}	Volume flow rate of MG sent to qualifying device **i** for destruction during time interval **t** captured from pre-mining surface wells that were mined through during earlier reporting periods (scfm)
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)

C_{CH4_t}	Measured methane concentration of mine gas sent to qualifying device **i** for destruction during time interval **t**; calculated separately for each methane source (scfm CH_4/scfm)

Equation 22: Eligible MG from Existing Coalbed Methane Wells that Would Otherwise Be Shut-in and Abandoned as a Result of Encroaching Mining

$$ECW_{flow_t} = \sum_t \left(ECW_{pre_t} \times T \times C_{CH4_t}\right) + \left(ECW_{post_t} \times T \times C_{CH4_t}\right)$$

WHERE

ECW_{flow_t}	Volume flow rate of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent for destruction to qualifying destruction device **i** during time interval **t** for use in Equation 20 (scfm)
ECW_{pre_t}	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, from the beginning of the crediting period through the end of the reporting period, captured from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during the reporting period (scfm)
ECW_{post_t}	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t** in the reporting period captured from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during earlier reporting periods (scfm)
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
C_{CH4_t}	Measured methane concentration of mine gas sent to qualifying device **i** for destruction during time interval **t**; calculated separately for each methane source (scfm CH_4/scfm)

Equation 23: Eligible MG from Abandoned Wells that are Reactivated

$$\mathbf{AWR_{flow_t}} = \sum_{t} \left(\mathbf{AWR_{pre_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right) + \left(\mathbf{AWR_{post_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right)$$

WHERE

AWR_{flow_t}	Volume flow rate of MG from abandoned wells that are reactivated that is sent for destruction to qualifying destruction device **i** during time interval **t** that is eligible for quantification in the reporting period for use in Equation 20 (scfm)
AWR_{pre_t}	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, from the beginning of the crediting period through the end of the reporting period, captured from abandoned wells that are reactivated that were mined through during the current reporting period (scfm)
AWR_{post_t}	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t** in the reporting period captured from abandoned wells that are reactivated that were mined through during earlier reporting periods (scfm)
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
C_{CH4_t}	Measured methane concentration of mine gas sent to qualifying device **i** for destruction during time interval **t**; calculated separately for each methane source (scfm CH_4/scfm)

Equation 24: Eligible MG from Converted Dewatering Wells that are Reactivated

$$\mathbf{CDW_{flow_t}} = \sum_{t} \left(\mathbf{CDW_{pre_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right) + \left(\mathbf{CDW_{post_t}} \times \mathbf{T} \times \mathbf{C_{CH4_t}}\right)$$

WHERE

CDW_{flow_t}	Volume flow rate of MG from converted dewatering wells sent for destruction to qualifying destruction device **i** during time period **t** for use in Equation 20 (scfm)

CDW_{pre_t}	Volume flow rate of MG sent to for destruction to qualifying destruction device **i**, from the beginning of the crediting period through the end of time period **t**, captured from converted dewatering wells that were mined through during the reporting period (scfm)
CDW_{post_t}	Volume flow rate of MG sent to for destruction to qualifying destruction device **i** during time period **t** captured from converted dewatering wells that were mined through during earlier reporting periods (scfm)
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
C_{CH4_t}	Measured methane concentration of mine gas sent to qualifying device **i** for destruction during time interval **t**; calculated separately for each methane source (scfm CH_4/scfm)

5.3.2 Quantifying Project Emissions

I. Project emissions must be quantified during the entire reporting period.
II. Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 3 and using Equation 25.
III. SMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 25: Project Emissions

$$\mathbf{PE = PE_{EC} + PE_{MD} + PE_{UM}}$$

WHERE

PE	Project emissions during the reporting period (MT CO_2e)
PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)
PE_{MD}	Project emissions from destruction of methane during the reporting period (MT CO_2e)

PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)

IV. If the project uses fossil fuel or grid electricity to power additional equipment required for project activities (e.g., drilling and completing additional wells or boreholes, capturing and destroying mine gas, transporting mine gas, etc.), the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 26.

V. If the total electricity generated by project activities is greater than the additional electricity consumed for the capture and destruction of methane, then $CONS_{ELEC} = 0$ in Equation 26.

Equation 26: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$\mathbf{PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1,000}}$$

WHERE

PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)
$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	CO_2 emission factor of electricity used from Table 10 in Appendix A (MT CO_2e/MWh)
$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{HEAT}	CO_2 emission factor of heat used from Equation 39 (kg CO_2/volume)
$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{FF}	CO_2 emission factor of fossil fuel used from Table 9 in Appendix A (kg CO_2/volume)

$\frac{1}{1{,}000}$	Conversion of kg to metric tons

VI. Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equation 27.

VII. Project emissions for pre-mining surface wells that are mined through during the reporting period must include the CO_2 emissions resulting from the destruction of all MG from the mined-through wells that took place during and prior to the reporting period.

Equation 27: Project Emissions from Destruction of SMM

$$\mathbf{PE_{MD}} = \sum_{\mathbf{i}} \sum_{\mathbf{t}} \mathbf{PE_{MD_{i,t}}}$$

AND

$$\mathbf{PE_{MD_{i,t}}} = \mathbf{MD_{i,t}} \times \mathbf{CEF_{CH4}}$$

WHERE

PE_{MD}	Project emissions from destruction of methane by all qualifying devices during the reporting period (MT CO_2e)
$PE_{MD_{i,t}}$	Project emissions from destruction of methane by qualifying destruction device **i** during time interval **t** (MT CO_2e)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying destruction devices
t	Time interval (not exceeding 15 minutes)
$MD_{i,t}$	Methane destroyed by qualifying device **i** during time interval **t**; calculated separately for each destruction device (MT CH_4)
CEF_{CH4}	CO_2 emission factor for combusted methane (2.744 MT CO_2e/MT CH_4)

VIII. The amount of mine methane destroyed ($MD_{i,t}$) must be quantified using Equation 28.

Equation 28: Methane Destroyed

$$\mathbf{MD_{i,t} = \left(MM_{i,t} \times DE_i\right)}$$

WHERE

$MD_{i,t}$	Methane destroyed through use $\mathbf{i}$ by qualifying devices during time interval $\mathbf{t}$; calculated separately for each destruction device (MT CH_4)
$MM_{i,t}$	Measured methane sent to qualifying devices for destruction through use $\mathbf{i}$ during time interval $\mathbf{t}$ (MT CH_4)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction device $\mathbf{i}$
t	Time interval (not exceeding 15 minutes)
DE_i	Efficiency of methane destruction device $\mathbf{i}$, either site-specific or from Table 12 in Appendix B (decimal)

WITH

$$\mathbf{MM_{i,t} = \sum_t \left[PSW_{flow_t} + ECW_{flow_t} + AWR_{flow_t} + CDW_{flow_t}\right] \times 0.0423 \times 0.000454}$$

WHERE

$MM_{i,t}$	Measured methane sent to qualifying devices for destruction through use $\mathbf{i}$ during time interval $\mathbf{t}$ (MT CH_4); calculated separately for each destruction device (MT CH_4)
PSW_{flow_t}	Volume flow rate of MG from pre-mining surface wells sent to qualifying device $\mathbf{i}$ for destruction during time interval $\mathbf{t}$ that is eligible for quantification in the reporting period quantified per Equation 21 (scfm)
ECW_{flow_t}	Volume flow rate of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent for destruction to qualifying destruction device $\mathbf{i}$ during time interval $\mathbf{t}$ quantified per Equation 22 (scfm)

AWR_{flow_t}	Volume flow rate of MG from abandoned wells that are reactivated that is sent for destruction to qualifying destruction device i during time interval t that is eligible for quantification in the reporting period quantified per Equation 23 (scfm)
CDW_{flow_t}	Volume flow rate of MG from converted dewatering wells sent for destruction to qualifying destruction device i during time period t quantified per Equation 24 (scfm)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction device i
t	Time interval (not exceeding 15 minutes)
0.0423	Standard density of methane (lb CH_4/scf CH_4)
0.000454	MT CH_4/lb CH_4

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

IX. Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 29.

X. Project emissions for pre-mining surface wells that are mined through during the reporting period must include the uncombusted methane portion of MG from the mined-through wells that was emitted during and prior to the reporting period.

Equation 29: Project Emissions from Uncombusted Methane

$$\mathbf{PE_{UM}} = \sum_{i} \sum_{t} \left[\mathbf{MM_{i,t}} \times (\mathbf{1} - \mathbf{DE_i})\right] \times \mathbf{GWP_{CH_4}}$$

WHERE

PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)

$MM_{i,t}$	Measured methane sent to qualifying device **i** during time period **t**; calculated separately for each destruction device per Equation 28 (MT CH_4)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction device **i**
DE_i	Efficiency of methane destruction device **i**, either site-specific or from Table 12 in Appendix B (decimal)
GWP_{CH_4}	Global warming potential of methane (MT CO_2e/MT CH_4)

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

XI. If gas flow metering equipment provides an actual or non-standardized flow rate or volume instead of a flow rate or volume adjusted to standard conditions, use Equation 42 to standardize the amount of MG sent to each qualifying device during the reporting period.

5.4 ABANDONED UNDERGROUND MINE METHANE RECOVERY ACTIVITIES

I. GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) using Equation 30.

Equation 30: GHG Emission Reductions

$$ER = BE - PE$$

WHERE

ER	Emission reductions achieved by the project during the reporting period (MT CO_2e)

BE	Baseline emissions during the reporting period (MT CO_2e)
PE	Project emissions during the reporting period (MT CO_2e)

5.4.1 Quantifying Baseline Emissions

II. Baseline emissions for a reporting period (BE) must be estimated by summing the baseline emissions for all SSRs identified as included in the baseline in Table 4 and using Equation 31.

III. BE_{MR} must account for the total amount of methane captured and sent to all qualifying devices during the reporting period.

IV. For abandoned underground mine methane drainage projects, baseline emissions equal methane released into the atmosphere during the reporting period.

Equation 31: Baseline Emissions

$$\mathbf{BE = BE_{MR}}$$

AND

$$\mathbf{BE_{MR} = \sum_{i}\sum_{t} BE_{MR_{i,t}}}$$

WHERE

BE	Baseline emissions during the reporting period (MT CO_2e)
BE_{MR}	Baseline emissions from methane captured and sent to qualifying destruction devices that would have been released to the atmosphere in the absence of the project (MT CO_2e)
$BE_{MR_{i,t}}$	Baseline emissions from methane captured and sent to qualifying destruction device $\mathbf{i}$ during time interval $\mathbf{t}$ that would have been released to the atmosphere in the absence of the project (MT CO_2e).
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, or alternative end-use) by qualifying destruction device $\mathbf{i}$
t	Time interval (not exceeding 15 minutes)

V. Baseline emissions from methane that would have been released to the atmosphere but that is captured and sent to qualifying destruction devices ($BE_{MR,i,t}$) must be quantified using Equation 32.

VI. AMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 32: Baseline Emissions from Release of Methane

$$\mathbf{BE_{MR_{i,t}} = \sum_{t} MM_{i,t} \times GWP_{CH4}}$$

WHERE

$BE_{MR_{i,t}}$	Baseline emissions from methane captured and sent to qualifying destruction device i during time interval t that would have been released to the atmosphere in the absence of the project (MT CO_2e)
$MM_{i,t}$	Measured methane sent for destruction to qualifying device i during time period t (MT CH_4)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction devices
t	Time interval (not exceeding 15 minutes)
GWP_{CH4}	Global warming potential of methane (MT CO_2e/MT CH_4)

VII. Measured methane sent to a qualifying destruction device ($MM_{i,t}$) is quantified using equation 33.

Equation 33: Baseline Emissions from Release of Methane

$$\mathbf{MM_{i,t} = \sum_{t} \left(IBPW_{flow_t} \times T \times C_{CH4_t}\right) \times 0.0423 \times 0.000454}$$

WHERE

$MM_{i,t}$	Measured methane sent for destruction to qualifying device i during time interval t (MT CH_4)
$IBPW_{flow_t}$	Volume flow rate of MG from in-mine boreholes and post-mining wells sent to qualifying device i during time interval t (scfm)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying destruction devices
t	Time interval (not exceeding 15 minutes)
T	Duration of time interval (minutes)
C_{CH4_t}	Measured methane concentration of mine gas sent to qualifying destruction device i during time interval t (scfm CH_4/scfm)
0.0423	Standard density of methane (lb CH_4/scf CH_4)
0.000454	MT CH_4/lb CH_4

5.4.2 Quantifying Project Emissions

I. Project emissions must be quantified over the entire reporting period.
II. Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 4 and using Equation 34.
III. AMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 34: Project Emissions

$$\mathbf{PE} = \mathbf{PE_{EC}} + \mathbf{PE_{MD}} + \mathbf{PE_{UM}}$$

WHERE

PE	Project emissions during the reporting period (MT CO_2e)
PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)

PE_{MD}	Project emissions from destruction of methane during the reporting period (MT CO_2e)
PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)

IV. If the project uses fossil fuel or grid electricity to power additional equipment required for project activities (e.g., drilling and completing additional wells or boreholes, capturing and destroying mine gas, transporting mine gas, etc.), the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 35.

V. If the total electricity generated by project activities is greater than the additional electricity consumed for the capture and destruction of methane, then $CONS_{ELEC}$ = 0 in Equation 35.

Equation 35: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$\mathbf{PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1,000}}$$

WHERE

PE_{EC}	Project emissions from energy consumed to capture and destroy methane during the reporting period (MT CO_2e)
$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	CO_2 emission factor of electricity used from Table 10 in Appendix A (MT CO_2e/MWh)
$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{HEAT}	CO_2 emission factor of heat used from Equation 39 (kg CO_2/volume)
$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume). Default emission factors from drilling in Appendix A

CEF_{FF}	CO_2 emission factor of fossil fuel used from Table 9 in Appendix A (kg CO_2/volume)
$\frac{1}{1{,}000}$	Conversion of kg to metric tons

VI. Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equation 36.

Equation 36: Project Emissions from Destruction of Captured Methane

$$\mathbf{PE_{MD}} = \sum_{\mathbf{i}} \sum_{\mathbf{t}} \mathbf{PE_{MD_{i,t}}}$$

AND

$$\mathbf{PE_{MD_{i,t}}} = \mathbf{MD_{i,t}} \times \mathbf{CEF_{CH4}}$$

WHERE

PE_{MD}	Project emissions from destruction of methane by all qualifying devices during the reporting period (MT CO_2e)
$PE_{MD_{i,t}}$	Project emissions from destruction of methane by qualifying destruction device $\mathbf{i}$ during time interval $\mathbf{t}$ (MT CO_2e)
$MD_{i,t}$	Methane destroyed by qualifying device $\mathbf{i}$ during time interval $\mathbf{t}$; calculated separately for each destruction device (MT CH_4)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying destruction devices
t	Time interval (not exceeding 15 minutes)
CEF_{CH4}	CO_2 emission factor for combusted methane (2.744 MT CO_2e/MT CH_4)

VII. The amount of methane destroyed ($MD_{i,t}$) must be quantified using Equation 37.

Equation 37: Methane Destroyed

$$\mathbf{MD_{i,t} = \left(MM_{i,t} \times DE_i\right)}$$

WHERE

$MD_{i,t}$	Methane destroyed through use **i** by qualifying devices during time interval **t**; calculated separately for each destruction device (MT CH_4)
$MM_{i,t}$	Measured methane sent to qualifying devices for destruction through use **i** during time interval **t** (MT CH_4)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)
DE_i	Efficiency of methane destruction device **i**, either site-specific or from Table 12 in Appendix B (decimal)

WITH

$$\mathbf{MM_{i,t} = \sum_t \left(IBPW_{flow_t} \times T \times C_{CH4,t}\right) \times 0.0423 \times 0.000454}$$

WHERE

$MM_{i,t}$	Measured methane sent to qualifying devices for destruction through use **i** during time interval **t** (MT CH_4)
$IBPW_{flow_t}$	Volume of MG from in-mine boreholes and post-mining wells sent to qualifying device **i** for destruction during time period **t** (scfm)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying destruction device **i**
t	Time interval (not exceeding 15 minutes)

$C_{CH4,t}$	Measured methane concentration of mine gas sent to qualifying destruction device i during time period t (scfm CH_4/scfm)
0.0423	Standard density of methane (lb CH_4/scf CH_4)
0.000454	MT CH_4/lb CH_4

Methane concentrations and flow rates must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

VIII. Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 38.

Equation 38: Uncombusted Methane Emissions

$$\mathbf{PE_{UM}} = \sum_{i} \sum_{t} \left[\mathbf{MM_{i,t}} \times (\mathbf{1} - \mathbf{DE_i})\right] \times \mathbf{GWP_{CH_4}}$$

WHERE

PE_{UM}	Project emissions from uncombusted methane during the reporting period (MT CO_2e)
$MM_{i,t}$	Measured methane sent for destruction to qualifying device i during time period t; calculated separately for each destruction device per Equation 37 (MT CH_4)
i	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline etc.) by all qualifying destruction device i
DE_i	Efficiency of methane destruction device i, either site-specific or from Table 12 in Appendix B (decimal)
GWP_{CH_4}	Global warming potential of methane (MT CO_2e/MT CH_4)

Methane concentrations and flow rate recordings must not exceed fifteen-minute intervals.

If a mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

IX. If gas flow metering equipment provides an actual or non-standardized flow rate or volume instead of a flow rate or volume adjusted to standard conditions, use Equation 42 to standardize the amount of MG sent to each qualifying device during the reporting period.

6 MONITORING – QUANTIFICATION METHODOLOGY

6.1 GENERAL MONITORING REQUIREMENTS

I. The Project Proponent is responsible for monitoring the performance of the offset project and operating each component of the collection and destruction system(s) in a manner consistent with the manufacturer's specifications.

II. Operational activity of the methane drainage and ventilation systems and the destruction devices must be the same as time interval t to ensure actual methane destruction. GHG reductions will not be accounted for during periods in which the destruction device is not operational.

   A. For flares, operation is defined as thermocouple readings above 500°F.

   B. For all other destruction devices, the Project Proponent must demonstrate the destruction device was operational. This demonstration is subject to the review and verification of the verification body.

III. If gas flow metering equipment does not internally adjust for temperature and pressure, flow data must be adjusted according to the appropriate quantification methodologies in chapter 5.

IV. If a project uses elevated amounts of atmospheric gases in extracted MG as evidence of a pre-mining well being mined through, nitrogen and oxygen concentrations must be determined for each well at the time of the project start date and when the Project Proponent reports a pre-mining well as eligible. Gas samples must be collected by a third-party technician and amounts of nitrogen and oxygen concentrations determined by a full gas analysis using a chromatograph at an ISO 17025 accredited lab or a lab that has been certified by an accreditation body conformant with ISO 17025 to perform test methods appropriate for atmospheric gas content analysis.

V. Data substitution is allowed for limited circumstances where a project encounters flow rate or methane concentration data gaps. Project Proponents may apply the data substitution methodology provided in Appendix D. No data substitution is permissible for data gaps resulting from inoperable equipment that monitors the proper functioning of destruction devices and no emission reductions will be credited under such circumstances.

6.2 INSTRUMENT QA/QC

Instruments and equipment used to monitor the destruction of mine methane or the temperature and pressure used to adjust data measurements to STP must be inspected, maintained, checked and calibrated according to the following:

I. All instruments must be:
   A. Inspected and maintained on a quarterly basis, with the activities performed and "as found/as left condition" of the equipment documented;
   B. Checked per manufacturer specifications by a trained professional for calibration accuracy (the project proponent may conduct this check) with the percent drift documented, with the check occurring no more than two months before the end date of the reporting period; and
   C. Calibrated by the manufacturer or a certified calibration service per manufacturer's specifications. Instruments are exempted from calibration requirements if the manufacturer's specifications state that no calibration is required.

II. A check must be performed before any corrective action (e.g., instrument calibration or repositioning) is applied.

III. If a portable instrument is used (such as a handheld methane analyzer), the portable instrument must be calibrated according to manufacturer's specifications prior to each use.

IV. For active underground VAM activities, the methane concentration of the reference gas used to check methane analyzers must be below or equal to 2% methane.

V. Flow meter and methane analyzer calibrations must be documented to show that the calibration was carried out to the range of conditions corresponding to the range of conditions as measured at the mine.

VI. If a check on a piece of equipment reveals accuracy beyond a +/- 5% threshold, all data from that piece of equipment must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful check until such time as corrective action is taken and a subsequent check demonstrates the equipment to again be within the +/-5% accuracy threshold.
   A. For each check that indicates the piece of equipment was beyond the +/- 5% accuracy threshold, the project developer shall calculate total emission reductions using:
      i. The monitored values without correction; and
      ii. The monitored values adjusted based on the calibration drift recorded at the time of the check.
   B. The lower of the two emission reduction estimates shall be reported as the scaled emission reduction estimate.

6.3 DOCUMENT RETENTION

I. The Project Proponent is required to keep all documentation and information outlined in this methodology. Record retention requirements are set forth in the ACR Standard.

II. Information that must be retained by the Project Proponent must include:

A. All data inputs for the calculation of the project baseline emissions and project emission reductions;

B. Emission reduction calculations;

C. NOVs, and any administrative or legal consent orders related to project activities dating back at least three years prior to the project start date and for each year of project operation;

D. Gas flow meter information (model number, serial number, manufacturer's calibration procedures);

E. Methane analyzer information (model number, serial number, manufacturer's calibration procedures);

F. Cleaning and inspection records for all gas meters;

G. Field check results for all gas meters and methane analyzers;

H. Calibration results for all gas meters and methane analyzers;

I. Corrective measures taken if meter does not meet performance specifications;

J. Gas flow data (for each flow meter);

K. Methane concentration monitoring data;

L. Gas temperature and pressure readings (only if flow meter does not adjust for temperature and pressure automatically);

M. Destruction device information (model numbers, serial numbers, installation date, operation dates);

N. Destruction device monitoring data (for each destruction device);

O. All maintenance records relevant to the methane collection and/or destruction device(s) and monitoring equipment;

P. For any portable instrument used in the project, the following records must be maintained:

i. Measurement instrument information (model number and serial number);

ii. Date, time, and results of instrument calibration; and

iii. Corrective measures taken if instrument does not meet performance specifications.

Q. If using a calibrated portable gas analyzer for CH_4 content measurement the following records must be retained:

i. Date, time, and location of methane measurement;

ii. Methane content of gas (% by volume or mass) for each measurement;
iii. Methane measurement instrument information (model number and serial number);
iv. Date, time, and results of instrument calibration; and
v. Corrective measures taken if instrument does not meet performance specifications.

6.4 ACTIVE UNDERGROUND MINE VENTILATION AIR METHANE ACTIVITIES

I. The flow rate of ventilation air entering the destruction device must be measured continuously, recordings must not exceed fifteen-minute intervals, and adjusted for temperature and pressure, if applicable.
II. The methane concentration of the ventilation air entering the destruction device and of the exhaust gas leaving the destruction device must be measured continuously, and recordings must not exceed fifteen-minute intervals to calculate methane concentrations.
III. If required in order to standardize the flow rate, volume, or mass of ventilation air, the temperature and pressure in the vicinity of the flow meter must be measured continuously and recorded at the same interval as time interval t.
IV. Project Proponents must monitor the parameters prescribed in Table 5. Data measurements may be recorded in an alternative unit, but must be appropriately converted to specified unit for use in equations provided in chapter 5.

Table 5: Active Underground Mine VAM Activity Monitoring Parameters

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
37	$C_{CH4,t}$	Measured methane concentration of ventilation air sent to a qualifying destruction device **i** for time interval **t**	scfm CH_4/scfm	Continuously	M, C	Selected time interval cannot exceed fifteen minutes

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
37 8	$VA_{flow,t}$	Flow rate of ventilation air sent to a qualifying device for destruction through use **i** during the time interval **t**	scfm	Continuously	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 41
7 8	$CA_{flow,t}$	Flow rate of cooling air sent to a destruction device after the metering point of the ventilation air stream during the reporting period	scfm	Continuously	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable using Equation 41. If the flow of cooling air is not metered, the maximum capacity of the air intake system must be used for the flow
3 7	$MG_{flow,t}$	Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; Adjusted to standard con-

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		device i for destruction during time interval t				ditions, if applicable, using Equation 42
37	$C_{CH4,MG,,t}$	Measured methane concentration of mine gas sent with ventilation air to destruction device i during time interval t	scfm CH_4/scfm	Continuously	M, C	Selected time interval cannot exceed fifteen minutes
5	$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period	MWh	Every reporting period	O	From electricity use records
5	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From heat use records
5	$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From fuel use records
41	$VA_{actual,t}$	Measured flow rate or total volume of ventilation air sent to a	acfm or acf	Continuously	M, C	Readings not exceeding fifteen minutes to calculate

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		qualifying destruction device i during tome interval **t**				temperature for time interval **t**
41	$T_{VAinflow,t}$	Measured absolute temperature of ventilation air sent to a destruction device for the time interval **t**, °R=°F + 459.67	°R	Continuously	M, C	Readings taken the same as time interval **t** to calculate temperature for
41	$P_{VAinflow,t}$	Measured absolute pressure of ventilation air sent to a destruction device for the time interval **t**	atm	Continuously	M, C	Readings taken the same as time interval **t** to calculate pressure

6.5 ACTIVE UNDERGROUND MINE METHANE DRAINAGE ACTIVITIES

I. Mine gas from each methane source (i.e., pre-mining surface wells, and in-mine boreholes and post-mining wells) must be monitored separately prior to interconnection with other MG sources. The volumetric or mass gas flow, methane concentration, temperature, and pressure must be monitored and recorded separately for each methane source.

II. The flow rate of MG sent to a destruction device must be measured continuously, recordings must not exceed 15-minute intervals, and adjusted for temperature and pressure, if applicable, to calculate daily volume of MG sent to a destruction device. The flow of mine gas to a destruction device must be monitored separately for each destruction device, unless:

A. A project consists of destruction devices that are of identical efficiency and verified to be operational throughout the reporting period; then a single flow meter may be used to monitor gas flow to all destruction devices; or

B. A project consists of destruction devices that are not of identical efficiency, in which case the methane destruction efficiency of the least efficient destruction device must be used as the methane destruction efficiency for all destruction devices monitored by that meter.

III. If a project using a single meter to monitor gas flow to multiple destruction devices has any periods of time when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods of time will only be eligible provided that the offset verifier can confirm all of the following requirements and conditions are met:

A. The methane destruction efficiency of the least efficient downstream destruction device in operation must be used as the methane destruction efficiency for all destruction devices downstream of the single meter;

B. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and

C. For any period of time during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

IV. The methane concentration of the mine gas extracted from each methane source must be measured continuously, and recordings must not exceed 15-minute intervals to calculate methane concentration.

V. If required in order to adjust the flow rate, volume, or mass of mine gas, the temperature and pressure of the mine gas from each methane source must be measured continuously and recorded at the same interval as time interval t to calculate temperature and pressure.

VI. Project Proponents must monitor the parameters prescribed in Table 6. Data measurements may be recorded in an alternative unit, but must be appropriately converted to specified unit for use in equations provided in chapter 5.

Table 6: Active Underground Mine Methane Drainage Activity Monitoring Parameters

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
11 12 16 17	$C_{CH4,t}$	Measured methane concentration of mine gas sent to qualifying destruction devices **i** during time interval **t**	scfm CH_4/scfm	Continuously	M, C	Selected time interval cannot exceed fifteen minutes
11 16 17	$IBPW_{flow,t}$	Volume flow rate of MG from in-mine boreholes and post-mining wells sent to qualifying devices **i** during time interval **t**	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
11 16 17	$MG_{flow,t}$	Volume flow rate of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying device **i** for destruction during time interval **t**	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
12	$PSW_{pre,t}$	Volume flow rate of MG sent	scfm	Every reporting period	M, C	Selected time interval cannot exceed

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		to qualifying destruction devices i during time interval t, from the beginning of the crediting period through the end of the reporting period, captured from pre-mining surface wells that were mined through during the reporting period				fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
12	$PSW_{post,t}$	Volume flow rate of MG sent to qualifying destruction device i during time period t in the reporting period; captured from pre-mining surface wells that were mined through during earlier reporting periods	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
14	$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period	MWh	Every reporting period	O	From electricity use records

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
14	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From heat use records
14	$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From fuel use records
16 17	$PSW_{flow,t}$	Volume flow rate of MG from pre-mining surface wells sent to qualifying device $\mathbf{i}$ during time interval $\mathbf{t}$	scfm	Continuously	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
16 17	DE_i	Efficiency of methane destruction device $\mathbf{i}$	%	Each reporting period	R or M	Default methane destruction efficiencies provided in Appendix B or site-specific methane destruction efficiencies approved by validation and

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
						verification body
42	$MG_{actual,t}$	Measured flow rate or total volume of MG sent to a qualifying destruction device **i** during time interval **t**	acfm or acf	Continuously	M	Readings not exceeding fifteen minutes to calculate temperature for time interval **t**
42	$T_{MG,t}$	Measured absolute temperature of MG for the time interval **t**, °R=°F + 459.67	°R	Continuously	M, C	Readings taken the same as time interval t to calculate temperature
42	$P_{MG,t}$	Measured absolute pressure of MG for the time interval **t**	atm	Continuously	M, C	Readings taken the same as time interval t to calculate pressure

6.6 ACTIVE SURFACE MINE METHANE DRAINAGE ACTIVITIES

I. Mine gas from each methane source (i.e., pre-mining surface wells, , existing CBM wells that would otherwise be shut-in and abandoned as a result of encroaching mining, abandoned wells that reactivated, and converted dewatering wells) must be monitored separately prior to interconnection with other MG sources. The volumetric or mass gas flow, methane concentration, temperature, and pressure must be monitored and recorded separately for each methane source.

II. The flow rate of MG sent to a destruction device must be measured continuously, recordings must not exceed 15-minute intervals, and adjusted for temperature and pressure, if

applicable, to calculate daily volume of MG sent to a destruction device. The flow of gas to a destruction device must be monitored separately for each destruction device, unless:

A. A project consists of destruction devices that are of identical efficiency and verified to be operational throughout the reporting period; then a single flow meter may be used to monitor gas flow to all destruction devices; or

B. A project consists of destruction devices that are not of identical efficiency, in which case the methane destruction efficiency of the least efficient methane destruction device must be used as the methane destruction efficiency for all destruction devices monitored by that meter.

III. If a project using a single meter to monitor gas flow to multiple destruction devices has any periods of time when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods of time will only be eligible provided that the offset verifier can confirm all of the following requirements and conditions are met:

A. The methane destruction efficiency of the least efficient downstream destruction device in operation must be used as the methane destruction efficiency for all destruction devices downstream of the single meter;

B. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and

C. For any period of time during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

IV. The methane concentration of the SMM extracted from each methane source must be measured continuously, and recordings must not exceed 15-minute intervals to calculate methane concentration.

V. If required in order to adjust the flow rate, volume, or mass of mine gas, the temperature and pressure of the SMM must be measured continuously and recorded at the same interval as time interval t to calculate temperature and pressure.

VI. Project Proponents must monitor the parameters prescribed in Table 7. Data measurements may be recorded in an alternative unit, but must be appropriately converted to specified unit for use in equations provided in chapter 5.

Table 7: Active Surface Mine Methane Drainage Activity Monitoring Parameters

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
20 28 29	$C_{CH4,t}$	Measured methane concentration of mine gas sent to a qualifying destruction device **i** during time interval t	scfm CH_4/scfm	Continuously	M, C	Selected time interval cannot exceed fifteen minutes; calculated separately for each methane source
21	$PSW_{pre,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, from the beginning of the crediting period through the end of the reporting period, captured from pre-mining surface wells that were mined through during the reporting period	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
21	$PSW_{post,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**; in the reporting period captured from pre-mining surface wells that were mined	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		through during earlier reporting periods				
22	$ECW_{pre,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, from the beginning of the crediting period through the end of the reporting period, captured from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during the reporting period	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
22	$ECW_{post,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, in the reporting period captured from existing coalbed methane wells that would otherwise be shut-	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		in and abandoned as a result of encroaching mining that were mined through during earlier reporting periods				
23	$AWR_{pre,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, from the beginning of the crediting period through the end of the reporting period, captured from abandoned wells that are reactivated that were mined through during the reporting period	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
23	$AWR_{post,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, in the reporting period captured from abandoned wells that are reactivated that were mined	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		through during earlier reporting periods				
24	$CDW_{pre,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t**, from the beginning of the crediting period through the end of the reporting period, captured from converted dewatering wells that were mined through during the reporting period	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
24	$CDW_{post,t}$	Volume flow rate of MG sent to qualifying destruction device **i** during time interval **t** in the reporting period captured from converted dewatering wells that were mined through during earlier reporting periods	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
26	$CONS_{ELEC}$	Additional electricity consumption for the cap-	MWh	Every reporting period	O	From electricity use records

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		ture and destruction of methane during the reporting period				
26	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From heat use records
26	$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From fuel use records
28 29	$PSW_{flow,t}$	Volume flow rate of MG from pre-mining surface wells sent to qualifying destruction device **i** during time interval **t**	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
28 29	$ECW_{flow,t}$	Volume flow rate of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a re-	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard con-

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
		sult of encroaching mining sent to qualifying device **i** during time interval **t**				ditions, if applicable, using Equation 42
28 29	$AWR_{flow,t}$	Volume flow rate of MG from abandoned wells that are reactivated sent to qualifying device **i** during time period **t**	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
28 29	$CDW_{flow,t}$	Volume of MG from converted dewatering wells sent to qualifying device **i** for destruction during time period **t**	scfm	Every reporting period	M, C	Selected time interval cannot exceed fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
28 29	DE_i	Efficiency of methane destruction device **i**	%	Each reporting period	R or M	Default methane destruction efficiencies provided in Appendix B or site-specific methane destruction efficiencies approved by the validation and

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
						verification body
42	$MG_{actual,t}$	Measured flow rate or total volume of MG sent to a destruction device **i** during time interval **t**	acfm or acf	Continuously	M	Readings not exceeding fifteen minutes to calculate temperature for time interval **t**
42	$T_{MG,t}$	Measured absolute temperature of MG for the time interval **t**, °R=°F +459.67	°R	Continuously	M, C	Readings taken the same as time interval **t** to calculate temperature
42	$P_{MG,t}$	Measured absolute pressure of MG for the time interval **t**	atm	Continuously	M, C	Readings taken the same as time interval **t** to calculate pressure

6.7 ABANDONED UNDERGROUND MINE METHANE RECOVERY ACTIVITIES

I. Mine gas from the methane source (i.e., in-mine boreholes and post-mining wells drilled into the mine during or after active mining operations) can be monitored in at a single location, but abandoned mine MG must be monitored separately prior to interconnection with any active mine MG sources. The volumetric or mass gas flow, methane concentration, temperature, and pressure must be monitored and recorded separately for each methane source.

II. The flow rate of MG sent to a destruction device must be measured continuously, recordings must not exceed 15-minute intervals, and adjusted for temperature and pressure, if applicable, to calculate daily volume of MG sent to a destruction device. The flow of gas to a destruction device must be monitored separately for each destruction device, unless:
   A. A project consists of destruction devices that are of identical efficiency and verified to be operational throughout the reporting period; then a single flow meter may be used to monitor gas flow to all destruction devices; or
   B. A project consists of destruction devices that are not of identical efficiency, in which case the methane destruction efficiency of the least efficient destruction device must be used as the methane destruction efficiency for all destruction devices monitored by that meter.

III. If a project using a single meter to monitor gas flow to multiple destruction devices has any periods of time when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods of time will only be eligible provided that the offset verifier can confirm all of the following requirements and conditions are met:
   A. The methane destruction efficiency of the least efficient downstream destruction device in operation must be used as the methane destruction efficiency for all destruction devices downstream of the single meter;
   B. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and
   C. For any period of time during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

IV. The methane concentration of the MG must be measured continuously, and recordings must not exceed 15-minute intervals to calculate methane concentration.

V. If required in order to adjust the flow rate, volume, or mass of AMM, the temperature and pressure of the AMM must be measured continuously and recorded at the same time interval as time interval t to calculate temperature and pressure.

VI. Project Proponents must monitor the parameters prescribed in Table 8. Data measurements may be recorded in an alternative unit, but must be appropriately converted to specified unit for use in equations provided in chapter 5.

Table 8: Abandoned Underground Mine Methane Recovery Activity Monitoring Parameters

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
33 37 38	$IBPW_{flow,t}$	Volume flow rate of MG from in-mine boreholes and post-mining wells sent to qualifying device i during time interval t	scfm	Every reporting period	M, C	Readings not exceeding fifteen minutes; adjusted to standard conditions, if applicable, using Equation 42
33 37 38	$C_{CH4,}$	Measured methane concentration of mine gas sent to a destruction device i during time interval t	scfm CH_4/scfm	Continuously	M, C	Readings not exceeding fifteen minutes;
35	$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period	MWh	Every reporting period	O	From electricity use records
35	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From heat use records

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
35	$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	O	From fuel use records
37 38	DE_i	Efficiency of methane destruction device **i**	%	Each reporting period	R or M	Default methane destruction efficiencies provided in Appendix B or site-specific methane destruction efficiencies approved by the validation and verification body
42	$MG_{actual,t}$	Measured flow rate or total volume of MG sent to a destruction device **i** during time interval **t**	acfm or acf	Continuously	M	Readings not exceeding fifteen minutes to calculate temperature for time interval **t**
42	$T_{MG,t}$	Measured absolute temperature of MG for the time interval **t**, °R=°F + 459.67	°R	Continuously	M, C	Readings taken the same as time interval **t** to calculate temperature

EQUATION #	PARAMETER	DESCRIPTION	DATA UNIT	MEASUREMENT FREQUENCY	CALCULATED (C) MEASURED (M) REFERENCE (R) OPERATING RECORDS (O)	COMMENT
42	$P_{MG,t}$	Measured absolute pressure of MG for the time interval **t**	atm	Continuously	M, C	Readings taken the same as time interval **t** to calculate pressure

7 VERIFICATION REQUIREMENTS

I. See the ACR Standard for guidance on project validation and verification requirements.

II. Project Proponents are responsible for producing mine and project records requested by the validation and verification body, which could include, but is not limited to, the following:

A. Mine plans;

B. Mine ventilation plans;

C. Mine maps;

D. Mine operating permits, leases (if applicable), and air, water, and land use permits;

E. Inspection, cleaning, and calibration records for metering equipment; and

F. Source testing records for destruction devices that use site-specific methane destruction efficiencies.

DEFINITIONS

For the purposes of this methodology, the following definitions apply:

Abandoned Mine Methane (AMM)	Methane released from an abandoned mine.
Abandoned Underground Mine	A mine where all mining activity including mine development and mineral production has ceased, mine personnel are not present in the mine workings, and mine ventilation fans are no longer operative. A mine must provide evidence to demonstrate it to be abandoned by the Mine Safety and Health Administration (MSHA) or other applicable state, provincial, or federal agencies to be eligible for an abandoned mine methane recovery activity.
Abandoned Wells that are Reactivated	Wells drilled for producing natural gas, dewatering, or providing a conduit to the mine workings that are retrofitted to recover methane gas from the mine workings.
Active Surface Mine	A permitted mine in which the mineral lies near the surface and can be extracted by removing the covering layers of rock and soil. A mine must be classified by the Mine Safety and Health Administration (MSHA) or other applicable state, provincial, or federal agencies as active, intermittent, non-producing or temporarily idle in order to be eligible for an active surface mine methane drainage activity.
Active Underground Mine	A permitted mine most of which is located below the earth's surface. A mine must be classified by the Mine Safety and Health Administration (MSHA) or other applicable state, provincial, or federal agencies as active, intermittent, non-producing, or temporarily idle in order to be eligible for an active underground mine methane drainage or ventilation air methane activity.
Borehole	A hole made with a drill, augur, or other tool into a coal seam, mine void, or surrounding strata from which mine gas can be extracted. This includes boreholes designated as methane extraction boreholes as well as other utility boreholes from which methane can be extracted.
Coal	Solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite

Coal Bed Methane (CBM or Virgin Coal Bed Methane)	Methane-rich natural gas drained from coal seams and surrounding strata not disturbed by mining.
Coalbed Methane (CBM) Wells	Wells drilled to recover and produce coalbed methane. CBM wells can be considered pre-mining CMM wells, however the extraction, capture, and destruction of virgin coalbed methane unrelated to mining activities is not eligible under this methodology.
Converted Dewatering Wells	Wells originally drilled and used with pumping equipment to remove groundwater from areas near mining activities that are retrofitted to recover methane gas.
Emission Factor	See ACR Standard for definition
Enclosed Flare	A flare that is situated in an enclosure for the purposes of safety, efficiency and accurate measurement of gas combustion. For purposes of this methodology, an enclosed flare is considered a flare.
End-use Option	A method of methane destruction deemed either eligible or ineligible for the purpose crediting under this methodology.
Flare	A combustion device that with a flame used to burn gas when mixed with combustion air; may be classified as “open” or “enclosed”.
Flow Meter	Device used to measure the amount of gas flowing through a pipe as measured at a specific point(s).
Gas Treatment	Applying techniques to extracted mine gas such as dehydration, gas separation, and the removal of non-methane components to prepare the mine gas for an end-use management option, including pipeline injection.
Gob	The part of the mine from which the mineral and artificial supports have been removed and the roof allowed to fall in. Gob is also known as “Goaf.” Generally regarded as the area behind the supports of a longwall mining machine.
In-mine Boreholes	A borehole or well drilled into an unmined seam from within the mine to drain methane from the seam ahead of the advancement of mining.

Longwall	A method of underground mining where a mechanical shearer is pulled back and forth across a coal face and loosened coal falls onto a conveyor for removal from the mine.
Methane Drainage System (Drainage System)	A system that drains methane from coal or trona seams and/or surrounding rock strata and transports it to a common collection point. This includes drainage systems within the mine workings or on the surface. Methane drainage systems may comprise multiple methane sources.
Methane Source	A methane source type from the following categories in the aggregate: • Ventilation shafts • Pre-mining surface wells • In-mine boreholes and post-mining wells • Existing coalbed methane wells that would otherwise be shut-in and abandoned • Abandoned wells that are reactivated • Converted dewatering wells
Mine Gas (MG)	The untreated gas extracted from within a mine through a methane drainage system that often contains various levels of other components (e.g., nitrogen, oxygen, carbon dioxide, hydrogen sulfide, and nonmethane hydrocarbons) in addition to methane.
Mine Methane (MM)	Methane contained in mineral deposits and surrounding strata that is released as a result of mining operations; the methane portion of mine gas.
Mine Operator	Any owner, lessee, or other person who operates, controls, or supervises a coal or other mine or any independent contractor performing services or construction at such mine. For purposes of this methodology, the Mine Operator is the operating entity listed on the state, provincial, or federal mining permit.
Mine Safety and Health Administration (MSHA)	The U.S. federal agency that regulates mine health and safety.
Mining Activities	Activities related to mineral extraction from active surface or underground coal or trona mine.

Natural Gas Pipeline (Pipeline)	A high-pressure pipeline transporting saleable quality natural gas offsite to gathering or distribution systems, or directly to customers.
Offset Project Expansion	The addition of a new methane source or new destruction device to an existing MMC project. A methane source is deemed new if it is either drilled after the project start date or connected to a destruction device after the project start date. A destruction device is deemed new if it becomes operational after the project start date. Under certain circumstances, described in chapter 2, the addition of new methane sources or new destruction devices may qualify as a new MMC project or an offset project expansion. In those cases, a Project Proponent may choose how to define the addition. Offset project expansion, unlike the establishment of a new MMC project, will not result in a new project start date or crediting period. Offset project expansion, unlike the establishment of a new MMC project, allows the Project Proponent to submit a single monitoring report and undergo a single verification for the reporting period.
Open Flare	A flare in which the main flame is atop a stack and visible. For purposes of this methodology, an open flare is considered a flare.
Pre-Project Destruction Device (Pre-Project Device)	A destruction device that is operational at the mine prior to the project start date, except as specified in Section 2.4(II). A destruction device that is operational at the mine prior to the project start date is considered a non-qualifying destruction device even if retrofitted thereafter.
Post-mining Well	A well or borehole used to extract or vent methane from the underground mine workings or gob area. Post-mining wells may be drilled from the surface or within the mine during or after mining activities. This includes gob wells.
Pre-mining Surface Wells	A well or borehole drilled into an unmined seam from the surface to drain methane from the seam and surrounding strata, often months or years in advance of mining. This is also known as surface pre-mining boreholes, surface-to-seam boreholes, and surface-drilled directional boreholes.
Qualifying Destruction Device (Qualifying Device)	A destruction device that was not operational at the mine prior to the project start date, except as specified in Section 2.4(II). Methane destroyed by a qualifying device must be monitored for quantification of both the baseline and project scenarios.

Room and Pillar	A method of underground mining in which approximately half of the coal is left in place as “pillars” to support the roof of the active mining area while "rooms" of coal are extracted. Also known as pillar and stall or board and pillar method.
Shut-in	To close, temporarily, a well capable of production.
Standard Conditions (Standard Temperature and Pressure or STP)	For the purposes of this methodology, 60 degrees Fahrenheit and 14.7 pounds per square inch absolute (1 atm).
Standard Cubic Foot (scf)	For the purposes of this methodology, a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and 14.7 pounds per square inch (1 atm) of pressure.
Start-up period	The period between qualifying destruction device installation and the project start date. After the installation of the qualifying destruction device, the Project Proponent may run, tune, and test the system to ensure its operational quality. A start-up period must not exceed 9 months.
Strata	Plural of stratum, the layers of sedimentary rock surrounding a coal seam.
Surface Mine Methane (SMM)	Methane contained in mineral deposits and surrounding strata that is released as a result of surface mining operations.
Thermal Energy	The thermal output produced by a combustion source used directly as part of a manufacturing process, industrial/commercial process, or heating/cooling application, but not used to produce electricity.
Trona	A water-bearing sodium carbonate compound mineral that is mined and processed into soda ash or bicarbonate of soda.
Ventilation Air (VA)	The gas emitted from the ventilation system of a mine.
Ventilation Air Methane (VAM)	Methane contained in ventilation air.
Ventilation Air Methane Collection System	A system that captures all or a portion of the ventilation air methane from the ventilation system.

(VAM Collection System)	
Ventilation Shaft	A large diameter borehole used to supply fresh air underground or to remove contaminated air (methane and other gases) from an underground mine.
Ventilation System	A system of fans and barriers that provides a flow of air to underground workings of a mine for the purpose of sufficiently diluting and removing methane and other noxious gases in order to provide a safe working environment.
Well	A well drilled for exploration or extraction of natural gas from a coal seam, surrounding strata, or mine.

APPENDIX A: EMISSION FACTORS – QUANTIFICATION METHODOLOGY

Table 9: CO_2 Emission Factors for Fossil Fuel Use

FUEL TYPE	DEFAULT HIGH HEAT VALUE	DEFAULT CO_2 EMISSION FACTOR	DEFAULT CO_2 EMISSION FACTOR
COAL AND COKE	**MMBTU / SHORT TON**	**KG CO_2 / MMBTU**	**KG CO_2 / SHORT TON**
Anthracite	25.09	103.54	2597.819
Bituminous	24.93	93.40	2328.462
Subbituminous	17.25	97.02	1673.595
Lignite	14.21	96.36	1369.276
Coke	24.80	102.04	2530.592
Mixed (Commercial sector)	21.39	95.26	2037.611
Mixed (Industrial coking)	26.28	93.65	2461.122
Mixed (Electric Power sector)	19.73	94.38	1862.117
NATURAL GAS	**MMBTU / SCF**	**KG CO_2 / MMBTU**	**KG CO_2 / SCF**
(Weighted U.S. Average)	1.028×10^{-3}	53.02	0.055

FUEL TYPE	DEFAULT HIGH HEAT VALUE	DEFAULT CO_2 EMISSION FACTOR	DEFAULT CO_2 EMISSION FACTOR
PETROLEUM PRODUCTS	**MMBTU / GALLON**	**KG CO_2 / MMBTU**	**KG CO_2 / GALLON**
Distillate Fuel Oil No. 1	0.139	73.25	10.182
Distillate Fuel Oil No. 2	0.138	73.96	10.206
Distillate Fuel Oil No. 4	0.146	75.04	10.956
Distillate Fuel Oil No. 5	0.140	72.93	10.210
Residual Fuel Oil No. 6	0.150	75.10	11.265
Used Oil	0.135	74.00	9.990
Kerosene	0.135	75.20	10.152
Liquefied petroleum gases (LPG)	0.092	62.98	5.794
Propane	0.091	61.46	5.593
Propylene	0.091	65.95	6.001
Ethane	0.069	62.64	4.322
Ethanol	0.084	68.44	5.749
Ethylene	0.100	67.43	6.743
Isobutane	0.097	64.91	6.296
Isobutylene	0.103	67.74	6.977

FUEL TYPE	DEFAULT HIGH HEAT VALUE	DEFAULT CO_2 EMISSION FACTOR	DEFAULT CO_2 EMISSION FACTOR
PETROLEUM PRODUCTS	**MMBTU / GALLON**	**KG CO_2 / MMBTU**	**KG CO_2 / GALLON**
Butane	0.101	65.15	6.580
Butylene	0.103	67.73	6.976
Naphtha (<401 deg F)	0.125	68.02	8.503
Natural Gasoline	0.110	66.83	7.351
Other Oil (>401 deg F)	0.139	76.22	10.595
Pentanes Plus	0.110	70.02	7.702
Petrochemical Feedstocks	0.129	70.97	9.155
Petroleum Coke	0.143	102.41	14.645
Special Naphtha	0.125	72.34	9.043
Unfinished Oils	0.139	74.49	10.354
Heavy Gas Oils	0.148	74.92	11.088
Lubricants	0.144	74.27	10.695
Motor Gasoline	0.125	70.22	8.778
Aviation Gasoline	0.120	69.25	8.310
Kerosene-Type Jet Fuel	0.135	72.22	9.750
Asphalt and Road Oil	0.158	75.36	11.907
Crude Oil	0.138	74.49	10.280

FUEL TYPE	DEFAULT HIGH HEAT VALUE	DEFAULT CO_2 EMISSION FACTOR	DEFAULT CO_2 EMISSION FACTOR
OTHER FUELS (SOLID)	**MMBTU / SHORT TON**	**KG CO_2 / MMBTU**	**KG CO_2 / SHORT TON**
Municipal SolidWaste	9.95	90.7	902.465
Tires	26.87	85.97	2310.014
Plastics	38.00	75.00	2850.000
Petroleum Coke	30.00	102.41	3072.300
OTHER FUELS (GASEOUS)	**MMBTU / SCF**	**KG CO_2 / MMBTU**	**KG CO_2 / SCF**
Blast Furnace Gas	0.092×10^{-3}	274.32	0.025
Coke Oven Gas	0.599×10^{-3}	46.85	0.028
Propane Gas	2.516×10^{-3}	61.46	0.155
Fuel Gas	1.388×10^{-3}	59.00	0.082
BIOMASS FUELS (SOLID)	**MMBTU / SHORT TON**	**KG CO_2 / MMBTU KG**	**CO_2 / SHORT TON**
Wood and Wood Residuals	15.38	93.80	1442.644
Agricultural Byproducts	8.25	118.17	974.903
Peat	8.00	111.84	894.720
Solid Byproducts	25.83	105.51	2725.323
BIOMASS FUELS (GASEOUS)	**MMBTU / SCF**	**KG CO_2 / MMBTU**	**KG CO_2 / SCF**
Biogas (Captured methane)	0.841×10^{-3}	52.07	0.044

FUEL TYPE	DEFAULT HIGH HEAT VALUE	DEFAULT CO_2 EMISSION FACTOR	DEFAULT CO_2 EMISSION FACTOR
BIOMASS FUELS (GASEOUS)	**MMBTU / SCF**	**KG CO_2 / MMBTU**	**KG CO_2 / SCF**
Biogas (Captured methane)	0.841×10^{-3}	52.07	0.044
BIOMASS FUELS (LIQUID)	**MMBTU / GALLON**	**KG CO_2 / MMBTU**	**KG CO_2 / GALLON**
Ethanol	0.084	68.44	5.749
Biodiesel	0.128	73.84	9.452
Rendered Animal Fat	0.125	71.06	8.883
Vegetable Oil	0.120	81.55	9.786

Source: United States Environmental Protection Agency Mandatory Reporting of Greenhouse Gases (Title 40, Code of Federal Regulations, Part 98, Subpart C, Table C-1) (2013) http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/subpart_c_rule_part98.pdf.

Table 10: Emissions & Generation Resource Integrated Database (eGRID2016)

		ANNUAL OUTPUT EMISSION RATES	
EGRID SUBREGION ACRONYM	**EGRID SUBREGION NAME**	**(LB CO_2/MWh)**	**(METRIC TON CO_2/MWh)**
AKGD	ASCC Alaska Grid	1,072.3	0.486
AKMS	ASCC Miscellaneous	503.1	0.228
AZNM	WECC Southwest	1,043.6	0.473
CAMX	WECC California	527.9	0.239
ERCT	ERCOT All	1,009.2	0.458

FRCC	FRCC All	1,011.7	0.459
HIMS	HICC Miscellaneous	1,152.0	0.523
HIOA	HICC Oahu	1,662.9	0.754
MORE	MRO East	1,668.2	0.757
MROW	MRO West	1,238.8	0.562
NEWE	NPCC New England	558.2	0.253
NWPP	WECC Northwest	651.2	0.295
NYCW	NPCC NYC/Westchester	635.8	0.288
NYLI	NPCC Long Island	1,178.3	0.534
NYUP	NPCC Upstate NY	294.7	0.134
RFCE	RFC East	758.2	0.344
RFCM	RFC Michigan	1,272.0	0.577
RFCW	RFC West	1,243.4	0.564
RMPA	WECC Rockies	1,367.8	0.620
SPNO	SPP North	1,412.4	0.641
SPSO	SPP South	1,248.3	0.566
SRMV	SERC Mississippi Valley	838.9	0.381
SRMW	SERC Midwest	1,612.6	0.731
SRSO	SERC South	1,089.4	0.494
SRTV	SERC Tennessee Valley	1,185.4	0.538
SRVC	SERC Virginia/Carolina	805.3	0.365

U.S.	**998.4**	**0.453**

Source: U.S. EPA eGRID2016, Version 1.0 Year 2016 GHG Annual Output Emission Rates (Created February 2018) https://www.epa.gov/sites/production/files/2018-02/documents/egrid2016_summarytables.pdf.

Table 11: Default Emission Factors for Fuel Combustion During Gas Well Drilling

Diesel usage rate — as a function of drilling footage	1.55 gallons/ft

Source: California Air Resources Board, Emissions Inventory Technical Support Studies, Attachment L: Fuel Combustion for Oil and Gas Production (January 2003)

Equation 39: Calculating Heat Generation Emission Factor

$$\mathbf{CEF_{HEAT}} = \frac{\mathbf{CEF_{CO_{2i}}}}{\mathbf{Eff_{HEAT}}} \times \frac{\mathbf{44}}{\mathbf{12}}$$

WHERE

$\mathrm{CEF_{HEAT}}$	CO_2 emission factor for heat generation
$\mathrm{CEF_{CO_{2i}}}$	CO_2 emission factor of fuel used in heat generation (see Table 10)
$\mathrm{Eff_{HEAT}}$	Boiler efficiency of the heat generation (either measured efficiency, manufacturer nameplate data for efficiency, or 100%)
$\frac{44}{12}$	Carbon to carbon dioxide conversion factor

Equation 40: Converting from lbs CO_2/MWh to metric tons CO_2/MW

$$\mathbf{Metric\ Tons_{CO_2}} = \frac{\mathbf{lbs_{CO_2}}}{\mathbf{2204.62}}$$

APPENDIX B: DEVICE DESTRUCTION EFFICIENCIES – QUANTIFICATION METHODOLOGY

Table 12: Default Methane Destruction Efficiencies by Destruction Device

Open Flare	0.960
Enclosed Flare	0.995
Lean-burn Internal Combustion Engine	0.936
Rich-burn Internal Combustion Engine	0.995
Boiler	0.980
Microturbine or large gas turbine	0.995
Upgrade and use of gas as CNG/LNG fuel	0.950
Upgrade and injection into natural gas transmission and distribution pipeline	0.981

APPENDIX C: STANDARDIZED FLOW RATE ENTERING DESTRUCTION DEVICES

Equation 41: VA Flow Rate or Volume Adjusted for Temperature and Pressure

$$\mathbf{VA_{adjusted_t}} = \mathbf{VA_{actual_t}} \times \frac{\mathbf{519.67}}{\mathbf{T_{VA_{inflow_t}}}} \times \frac{\mathbf{P_{VA_{inflow_t}}}}{\mathbf{1}}$$

WHERE

$VA_{adjusted_t}$	Flow rate or total volume of ventilation air sent to a destruction device during time interval t, adjusted to standard conditions (scfm or scf)
VA_{actual_t}	Measured flow rate or total volume of ventilation air sent to a destruction device during time interval t (acfm or acf)
$T_{VA_{inflow_t}}$	Measured absolute temperature of ventilation air sent to a destruction device for the time interval t, °R = °F + 459.67 (°R)
$P_{VA_{inflow_t}}$	Measured absolute pressure of ventilation air sent to a destruction device for the time interval t (atm)

Equation 42: MG Flow Rate or Volume Adjusted for Temperature and Pressure

$$\mathbf{MG_{adjusted_t}} = \mathbf{MG_{actual_t}} \times \frac{\mathbf{519.67}}{\mathbf{T_{MG_t}}} \times \frac{\mathbf{P_{MG_t}}}{\mathbf{1}}$$

WHERE

$MG_{adjusted_t}$	Flow rate or total volume of MG sent to a destruction device during time interval t, adjusted to standard conditions (scfm or scf)
MG_{actual_t}	Measured flow rate or total volume of MG sent to a destruction device during time interval t (acfm or acf)

T_{MG_t}	Measured absolute temperature of MG for the time interval **y**, °R=°F + 459.67 (°R)
P_{MG_t}	Measured absolute pressure of ventilation air sent to a destruction device for the time interval **y** (atm)

APPENDIX D: DATA SUBSTITUTION METHODOLOGY – QUANTIFICATION METHODOLOGY

I. ACR expects that MMC projects will have continuous, uninterrupted data for the entire reporting period. However, ACR recognizes that unexpected events or occurrences may result in brief data gaps.

II. This Appendix provides a quantification methodology to be applied to the calculation of GHG emission reductions for MMC projects when data integrity has been compromised due to missing data points.

III. This methodology is applicable to monitored parameters used to quantify emission reductions such as gas flow metering and methane concentration parameters. Data substitution is not allowed for equipment that monitors the proper functioning of destruction devices such as thermocouples.

IV. This methodology may be used for missing temperature and pressure data used to adjust flow rates to standard conditions.

V. The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances.

VI. Substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

   A. Proper functioning can be evidenced by thermocouple readings for flares or engines, energy output for engines, etc.

   B. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.

   C. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

VII. If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology may be applied:

Table 13: Data Substitution Duration and Methodology

Less than six hours	Use the average of the four hours of normal operation immediately before and following the outage or a more conservative value.
Six to 24 hours	Use the 90% upper or lower confidence limit (whichever is more conservative) of the 24 hours of normal operation prior to and after the outage or a more conservative value.
One to seven days	Use the 95% upper or lower confidence limit (whichever is more conservative) of the 72 hours of normal operation prior to and after the outage or a more conservative value.
Greater than one week	No data may be substituted, and no credits may be generated

APPENDIX E: PERFORMANCE STANDARD FOR CANADA AND MÉXICO

The predominant mine methane methodology in use in the United States is the compliance offset methodology from the California Air Resources Board. In that methodology, only projects located in the United States are eligible. In this methodology, projects located in Canada and México are also eligible as presented in this Appendix.

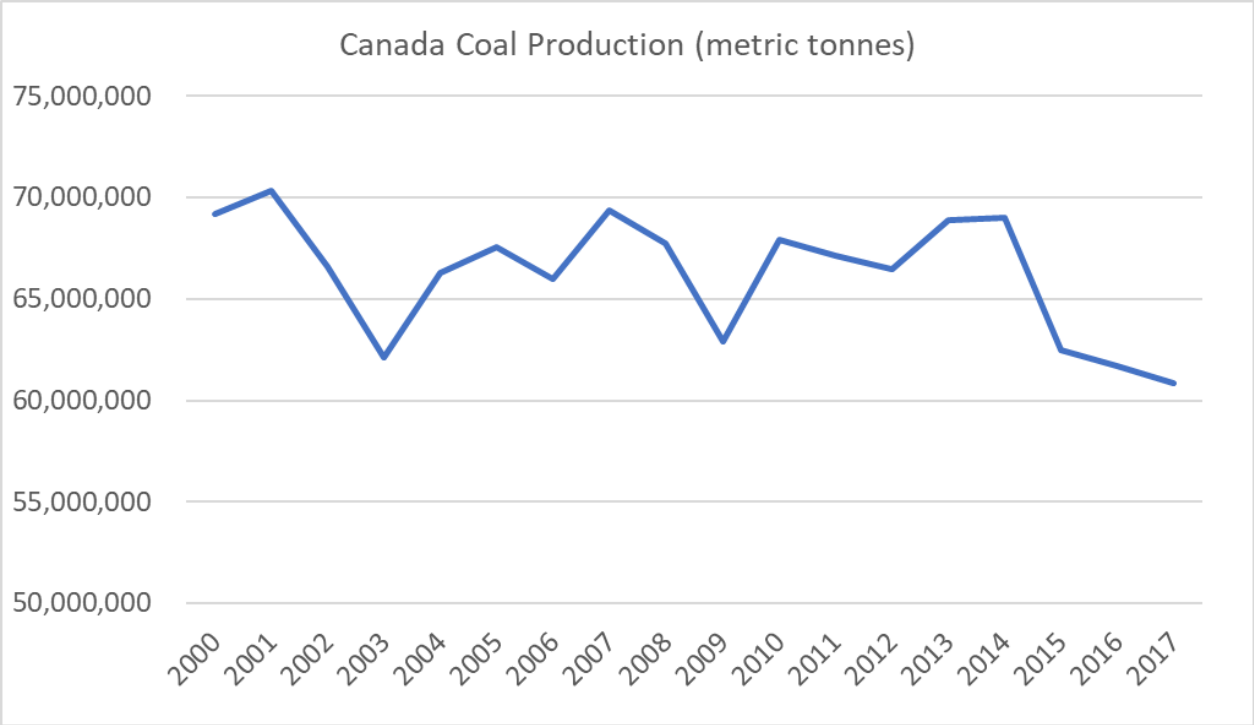
E.1 COAL INDUSTRY IN CANADA

Canada's coal resources extend across the country, but coal is actively mined only in Alberta, British Columbia, Saskatchewan, and Nova Scotia. Alberta and British Columbia produce 85% of Canada's coal. The country's coal production peaked in 1997 at 78 million tonnes, and since then, coal production has remained flat or has generally declined; it fell to an estimated 30-year low in 2016 at 60.4 million tonnes.

In recent years, just over half of Canada's coal production was metallurgical coal used for steel manufacturing and the rest was thermal coal used for electricity. The Government of Canada plans to eliminate the use of traditional coal-fired electricity in Canada by 2030; coal is still being mined but an increasing amount is exported. Canada exported 31 million tonnes of coal in 2017, primarily to Asian markets.

Most coal (97%) mined in Canada is from surface mines. In the last ten years there have only been two operating underground mines in Canada—the Grande Cache mine in Alberta and the Quinsam mine on Vancouver Island in British Columbia. A third underground mine, the Donkin mine in Cape Breton, Nova Scotia operated intermittently in 2017, 2018, and into 2019 because of safety concerns. Approximately 20 surface coal mines operated during the same time period. There are plans for additional underground operations—such as the Murray River Project in British Columbia—which may increase the contribution from underground mines in the future.

Figure 5. Coal Production in Canada



Source: Energy Statistics Canada

E.2 CMM EMISSIONS IN CANADA

Canada is home to 24 permitted coal mines, 19 of which operated in 2017. CMM emissions are limited to these locations as well as several abandoned underground mines. Environment and Climate Change Canada (ECCC) publishes annual fugitive methane emissions from coal mining in its National Inventory Reports (NIRs) and releases annual emissions data for individual coal mines in Canada gathered through its GHG Reporting Program. Emissions from active underground coal mines were estimated to be 90,000 tCO_2e in 2013, 108,000 tCO_2e in 2014, and 84,000 tCO_2e in 2015. Emissions from abandoned coal mines were estimated to be 100,000 tCO_2e in 2013, 54,000 tCO_2e in 2014, and 53,000 tCO_2e in 2015. During the same time period, emissions from surface mine activities were estimated to be about 900,000 tCO_2e annually.

The most recent NIR data is for 2016 when emissions were estimated to be 69,000 tCO_2e from abandoned coal mines and 0 tCO_2e from active underground coal mines because there were no producing underground mines. Surface mine emissions remained constant at 900,000 tCO_2e.

Two provinces, Alberta and British Columbia, also publish emissions data for individual mines gathered through their provincial-level GHG reporting programs. The data is somewhat inconsistent between British Columbia's provincial level data and ECCC's data, which is also inconsistent with NIR data, but this is likely the result of differences in methods for estimating emissions. ECCC and Alberta use IPCC Tier 2 equations to calculate emissions which include the application of an average emission rate; emissions estimates in British Columbia use measurements from the underground mines to calculate emissions.

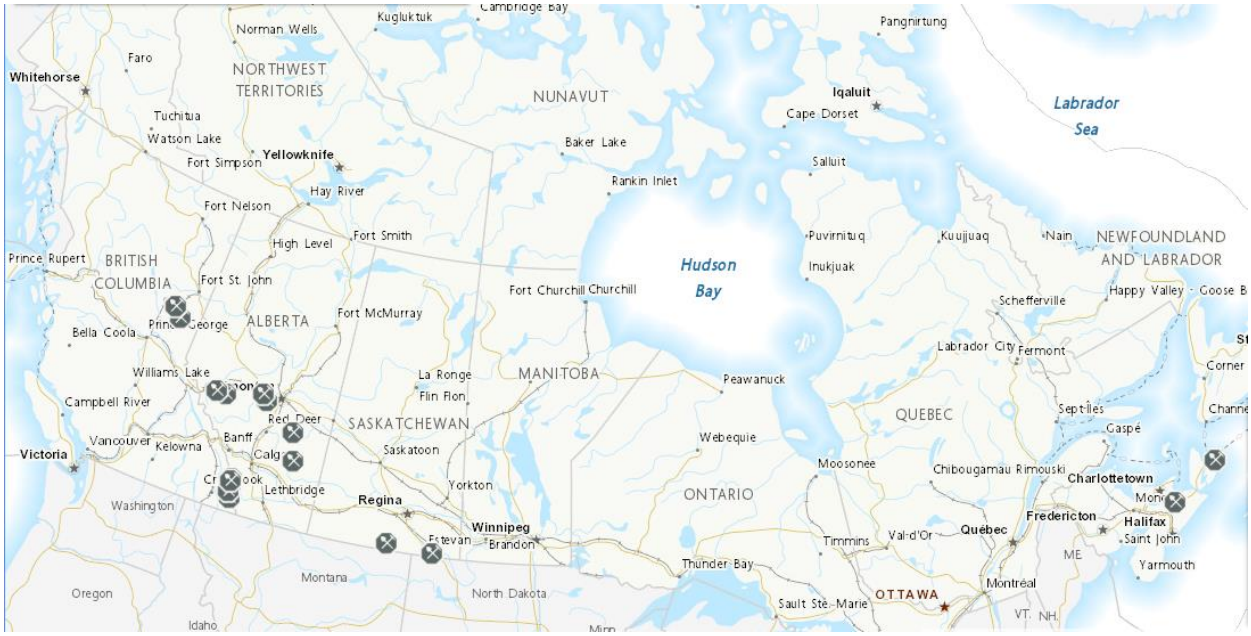
E.3 PROJECT OPPORTUNITIES IN CANADA

Opportunities for CMM recovery in Canada are limited. The total annual CMM emissions reported in Canada's NIRs over the past five years are about 1 million tCO_2e. There have not been any CMM utilization projects developed in the past, and there are currently no CMM utilization projects operating in Canada. As of 2018, underground coal mine methane project opportunity was limited to one gassy mine operating intermittently in Nova Scotia, while the largest source of CMM emissions is from surface mines operating in western Canada coalfields with coalbed methane potential.

Environment Canada estimates there to be over 1,400 abandoned underground coal mines in Canada; however, the number of those mines with high CMM emissions is unknown and could be less than 10%. The gassiest underground coal mines with the greatest methane potential are located in Nova Scotia, but Nova Scotia Environment confirmed that all mines were flooded as of 2013. The best remaining abandoned mine opportunities are located at non-flooded mines in Alberta and British Columbia.

Currently, no law, regulation, or legal mandate exists in Canada requiring the destruction of methane at coal mines. All emission reductions resulting from the recovery and destruction of mine methane are considered eligible for crediting under this performance standard.

Figure 6: Atlas of Coal Mines in Canada



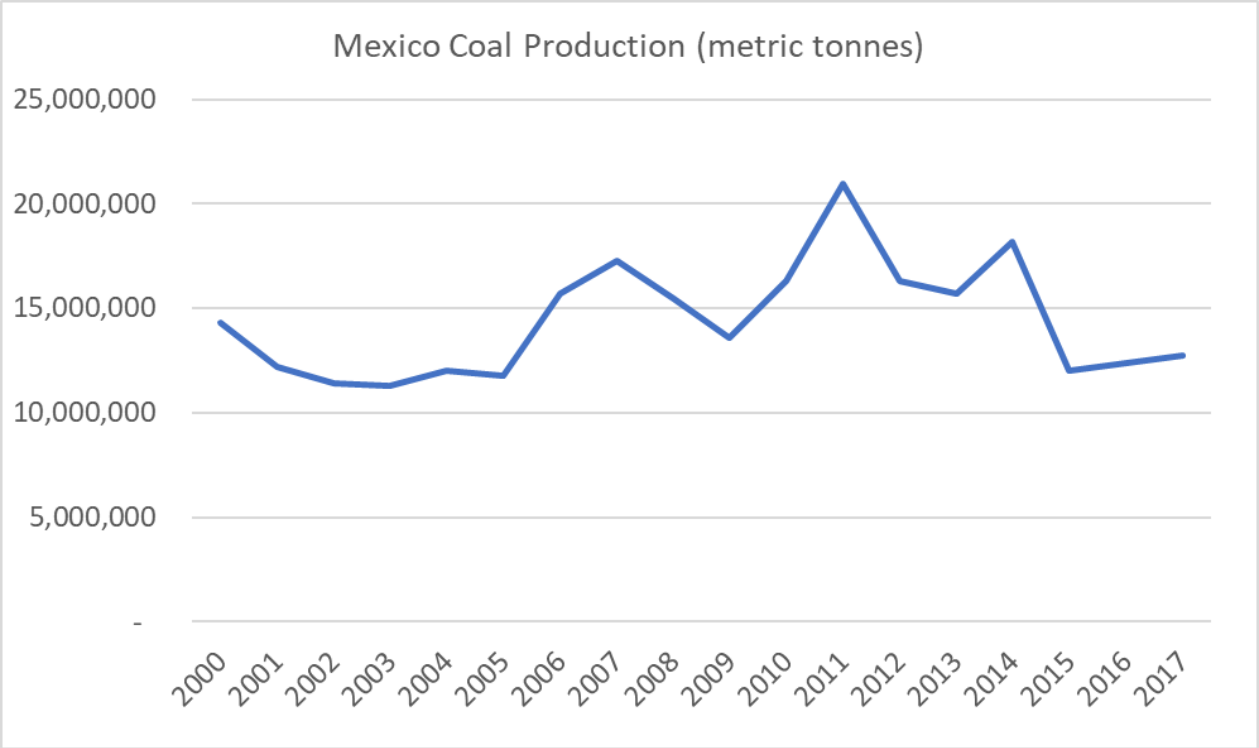
Source: Natural Resources Canada http://atlas.gc.ca/mins/en/index.html

E.4 COAL INDUSTRY IN MÉXICO

Approximately 95% of México's coal resources are located in northeast México in the State of Coahuila. According to the Mexican Geologic Service (Servicio Geológico Mexicano) there were at least 9 active mines operating in the state of Coahulia which represents 100% of coal production in México. Around 60% of the coal is used to generate electrical energy while the remainder is used to produce iron and steel (Geologia Económica de México).

Coal production peaked in México at about 21 million tons in 2011 when as many as 32 coal mines were operating. From 2015 to 2017, coal production was down to approximately 12-13 million tons/yr. with fewer mines operating. Five of the large active mines are gassy underground coal mines operated by Minera del Norte S.A. de C.V. (MIMOSA Unit). These mines produce most of México's coal. MIMOSA plans to develop a new area, the Conchas Mine Complex, with three underground mines (Minas IX, X, XI) in the southern Sabinas Basin.

Figure 7: Coal Production in México



Source: Mexican Mining Statistic Yearbook (Sistema Geológico Mexicano)

E.5 COAL MINE METHANE EMISSIONS IN MÉXICO

México's coal mine methane (CMM) emissions are estimated using IPCC Tier I default emission factors and are not reported based on methane measurements. Project feasibility studies have shown México coal mines to have higher methane emission rates than the IPCC defaults. Also, uncertainty exists with the coal production activity data used to estimate emissions. As a result, the applied Tier I method uncertainty for CMM emissions is a factor of 2. México's National Inventory Report for 2015 estimated CMM emissions to be greater than 7 million tCO_2e (with 98% from underground mines); however, the U.S. EPA estimated CMM emissions in México to be about 3 million tCO_2e in 2015, which was based on lower coal production numbers.

Between September 2011 and April 2014, MIMOSA developed a CMM destruction project by installing three enclosed flares – one at each of three mines: Mine V (Esmeralda), Mine VI, and Mine VII. The project destroys a portion of the methane recovered from the underground mines' gas drainage systems. The project was successfully registered as a CDM project in October

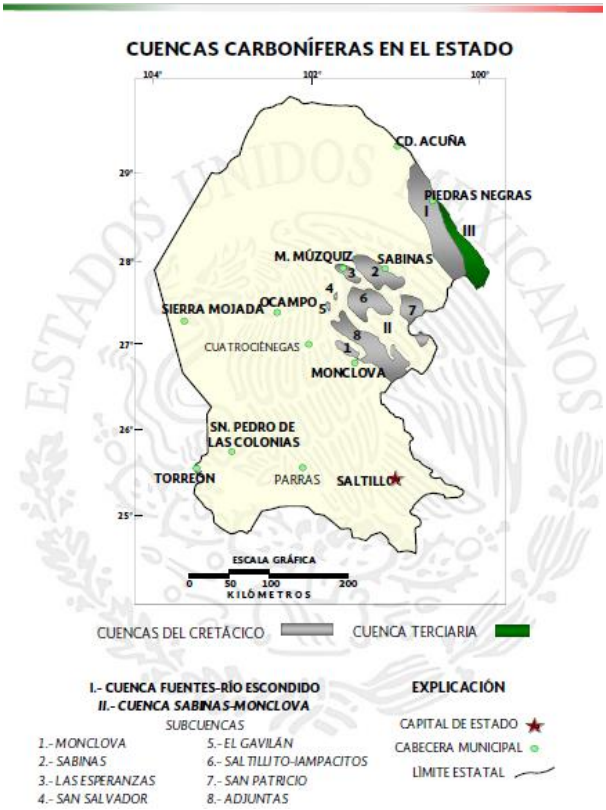
2013 with a fixed crediting period until October 2023. However, only the first monitoring period from October 2013 to October 2014 was verified with 85,865 tCO_2e (about 20% of the ex-ante estimate). The operational status of the project over the past four years is unknown as of 2018.

E.6 PROJECT OPPORTUNITIES IN MÉXICO

All CMM project opportunities (surface mines, underground mines, and abandoned underground mines) in México are located in the State of Coahuila. The largest opportunities reside with MIMOSA's underground mines (between 3-6 mines), which represent a large portion of total CMM emissions in México. Most emissions are from ventilation air methane (VAM) at vent shafts, but a significant amount of useable methane is recovered from gas drainage systems. MIMOSA also controls four abandoned underground mines with methane recovery opportunity.

Currently, no law, regulation, or legal mandate exists in México requiring the destruction of methane at coal mines. All emission reductions resulting from the recovery and destruction of mine methane are considered eligible for crediting under this performance standard.

Figure 8: Coal Basins in the State of Coahuila



Source: Panorama Minero del Estado de Coahulia del Servicio Geológico Mexicano

APPENDIX F: REFERENCES

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American Carbon Registry
AT WINROCK INTERNATIONAL

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RE-REFINING USED LUBRICATING OILS

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ACKNOWLEDGEMENTS

Support for the development of this methodology was provided by:

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ACRONYMS

API	American Petroleum Institute
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
Offsets	Carbon offset credits
SSR	GHG Source, Sink, or Reservoir
GWP	Global Warming Potential
VOC	Volatile Organic Compound

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1 BACKGROUND AND APPLICABILITY

1.1 SUMMARY DESCRIPTION OF THE METHODOLOGY

Lubricating oils are used to minimize friction and wear between mechanical parts in contact with each other and are essential to a wide variety of automotive, industrial, and marine applications. The lifecycle of lubricating oils is associated with environmental impacts including greenhouse gas emissions. The manufacture of lubricating oil is the most energy-intensive process in a crude oil refinery, and used lubricating oils are often burned in industrial or commercial boilers, releasing multiple pollutants including carbon dioxide.[1]

An alternative option exists for used lubricating oil: collection and re-refining. Used oil management programs have been developed throughout North America to reduce the amount of practical loss[2] of used oil and to encourage the recycle and reuse of used oil. Lubricating oil must be taken out of service when it no longer performs to expected specifications. This occurs when additive packages become depleted and the lubricant becomes contaminated. The base oil portion of the lubricant, however, does not break down during use. As a result, used engine oil and other lubricating oils can be re-refined to remove water, contaminants and additives to produce base oil of the same quality as the virgin base oil. Lubricants formulated using re-refined base oils in turn can meet the same performance standards as those using virgin base stocks.

The purpose of the Methodology is to quantify greenhouse gas (GHG) emission reductions associated with the re-refining of used lubricating oils. Re-refining used lubricating oils avoids GHG emissions associated with combustion of used oil. This Methodology provides the quantifi-

[1] Used lubricating oil is often improperly disposed, for example dumped into storm sewers or garbage bins, or burned in unregulated boilers. Burning used oil without proper controls releases harmful compounds into the atmosphere including Polycyclic Aromatic Hydrocarbons (PAHs) and heavy metals. Dumping used oil can impact both the environment and human health as contaminated oil migrates downward through soil and possibly impacting surface water, groundwater and causing soil contamination.

[2] Practical loss is the amount of used oil that is improperly disposed, discarded or burned for energy recovery prior to being collected as defined in the Kline/CalRecycle Report “Lubricant Consumption and Used Oil Generation in California: A Segmented Market Analysis”)

cation and accounting frameworks, including eligibility and monitoring requirements, for the creation of carbon offset credits from the reductions in GHG emissions resulting from the re-refining of used lubricating oils.

1.2 APPLICABILITY CONDITIONS

Finished lubricants are produced by blending base oil with additives to control viscosity and achieve specific quality and performance targets. Under a project scenario, used lubricating oil is collected and re-refined into base oil that meets the same rigid quality assurance/quality control standards referenced in API Standard Publication 1509 (Fifteenth Edition). Base oils derived from crude oil refining, chemical synthesis, and the re-refining of used lubricating oil must meet the American Petroleum Institute (API) standards or equivalent standards to deliver the same performance.

This Methodology defines a set of activities designed to reduce GHG emissions through the re-refining of used lubricating oils. This methodology is applicable under the following conditions:

- The re-refined lubricating oils produced by the project activity in a re-refinery (hereafter referred to as "Project Site") are of the same quality as virgin lubricating oils, as evidenced by the fact that they can be used for the same purpose and meet all relevant product specifications.
- The Project Site is in North America.
- Used lubricating oils eligible under this protocol are those included in the definition of used lubricating oils in the Definitions section.
- The Project complies with all local or national regulations related to proper treatment and disposal of contaminants.

1.3 START DATE

The project start date is the date on which the Project Site began to reduce GHG emissions against its baseline.

1.4 REPORTING PERIODS

- Projects may define the length of each reporting period taking into consideration ACR's requirements for validation and verification intervals[3].
- Emission reductions shall be quantified for the duration of the chosen reporting period based on the total amount of re-refined lubricating oil produced during the reporting period and the

[3] See the ACR Standard

subsequent sale, title transfer or return of the re-refined lubricating oil to a re-refined lubricating oil distributor, wholesaler, or end-user.

- A project's first reporting period may begin on the project start date or thereafter taking into consideration the timeframe during which project validation must be achieved following the project start date[4].

1.5 CREDITING PERIOD

- The crediting period begins on the first day of the first reporting period.
- The crediting period shall be ten years.

1.6 PERIODIC REVIEWS AND REVISIONS

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project's activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the Methodology.

[4] See the ACR Standard

2 PROJECT BOUNDARIES

2.1 GEOGRAPHIC BOUNDARY

The GHG assessment boundary, or offset project boundary, delineates the SSRs that must be included or excluded when quantifying the net changes in emissions associated with the re-refining of used lubricating oils.

The project boundary, depicted by the light grey box in Figure 1, include the physical and geographical sites where used lubricating oil is either burned as heating fuel, or re-refined for further use.

For purposes of this assessment, the extraction, transport, and refining of crude oil, and the collection, aggregation, and transport of used lubricating oil to locations where it is either burned as fuel or re-refined, and any associated GHG emissions, are not included in the project boundaries. The extraction, transport, and refining of crude oil has been excluded based on the assumption that extracted crude will most likely continue to be refined into other products despite adoption of lubricant re-refining processes. Avoided GHG emissions from displaced base oil production are also not included in this Methodology to prevent potential double-counting in jurisdictions with a GHG emission control program (either carbon tax or a cap-and-trade program). Also, the production of additives which are added to base oil to create finished lubricant products is not included. Lastly, the transportation and distribution emissions associated with re-refined lubricating oil are outside the project boundary and are excluded from project emissions.

Figure 1: Project Boundary Diagram for Re-refining Used Lubricating Oils

Illustration of the GHG assessment boundary for re-refining of used lubricating oils. SSRs inside the grey box are included and must be accounted for under this Methodology.

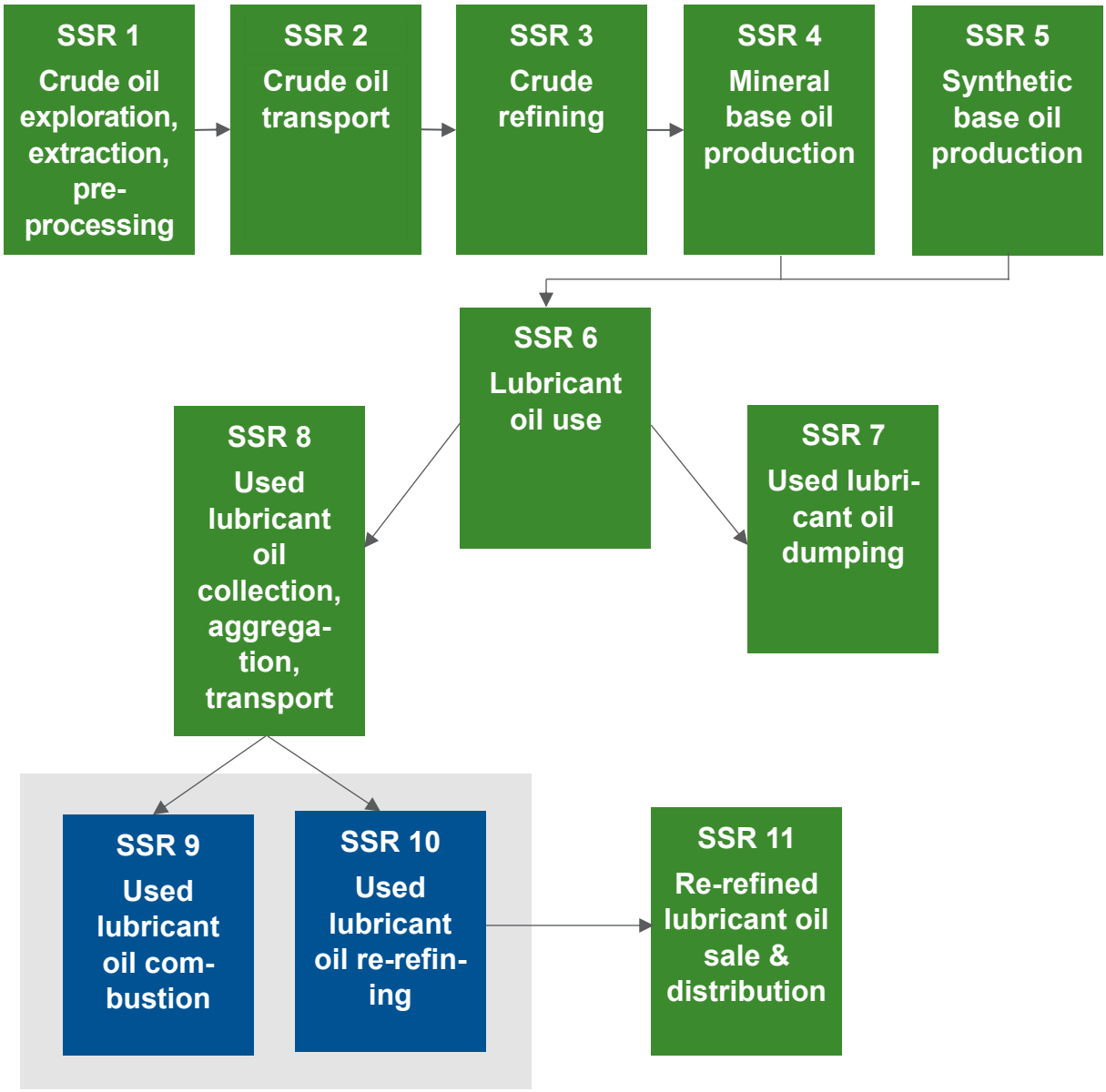


Table 1: Greenhouse Gases and Sources, Sinks and Reservoirs

List of the GHG sources included and excluded in the quantification under this Methodology, depending on whether the sources are within or outside project boundaries.

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFICATION METHOD
1	Crude Oil Exploration, Extraction, Processing	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
2	Crude Oil Transport	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
3	Crude Refining	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
4	Mineral Base Oil Production	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
5	Synthetic Base Oil Production	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
6	Lubricant Oil Use	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A

SSR	SOURCE DESCRIPTION	GAS	INCLUDED (I) OR EXCLUDED (E)	QUANTIFICATION METHOD
7	Used Lubricant Oil Dumping	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
8	Used Oil Collection, Aggregation, Transport	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A
9	Used Lubricant Oil Combustion	CO_2	I	Equations 1 and 5
		CH_4	E	N/A
		N_2O	E	N/A
10	Used Lubricant Oil Re-Refining	CO_2	I	Equations 3 and 4
		CH_4	E	N/A
		N_2O	E	N/A
11	Re-Refined Lubricant Oil Sale and Distribution	CO_2	E	N/A
		CH_4	E	N/A
		N_2O	E	N/A

3 BASELINE DETERMINATION

The baseline scenario considers:

- the baseline rates of used lubricant collection, re-refining and combustion for energy recovery;
- emission factors for combustion of used lubricating oil.

3.1 BASELINE RATES OF RE-REFINING AND COMBUSTION

The current rates by which lubricants are re-refined in North America are accounted for in determining the baseline scenario. An industry survey conducted in 2015 provides the most recent data on lubricant re-refining in North America[5] (Kline & Company, 2016).

Based on the Kline and Company survey, it is assumed that for the baseline scenario, of the used lubricant oil generated across North America that is collected or that could be collected (6,134 kt.), 13.6% (833 kt.) is re-refined into base oil (See Appendix A).

3.2 GHG EMISSIONS FROM COMBUSTION OF USED LUBRICATING OIL

GHG emissions from combustion of used lubricating oil are assessed in this Methodology. Burning used lubricating oil for heat recovery results in direct CO_2 emissions. Most lubricating oils are made from heavier, thicker, petroleum-base stock, and are designed for lubrication rather than as fuel. The hydrocarbon composition of lubricating oil varies, especially for used oil that is frequently mixed with heavy oils to improve the quality of the fuel. As such, a wide range of values are reported in the literature for the energy content of lubricating oils and resulting CO_2 emissions from combustion. This Methodology uses default factors from the IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 2006).

[5] Kline Report "Global Used Oil Markets and Re-Refined Lubricants 2015: Market Analysis and Opportunities – North America"), Kline &Company (2016).

4 ADDITIONALITY ASSESSMENT

Emission reductions from the project must be additional or deemed not to occur in the "business-as-usual" scenario. Assessment of the additionality of a project will be made based on passing the two tests cited below. These two tests require the project proponent to demonstrate that the project activity is surplus to regulations and reduces emissions below the level established in the Methodology.

1. Regulatory Surplus Test, and
2. Practice-Based Performance Standard

4.1 REGULATORY SURPLUS TEST

In order to pass the regulatory surplus test a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect as of the project start date that directly or indirectly affect the credited GHG emissions associated with a project. The project proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated re-refining used lubricating oil.

Currently, there are no such requirements in the U.S. or elsewhere in North America. Consumers are free to use virgin lubricating oil or re-refined lubricating oil in any amount. Likewise, there are no restrictions in North America on the quantities of re-refined lubricating oil that can be produced, imported, or used for any application.

4.2 PRACTICE-BASED PERFORMANCE STANDARD

The second test is whether used lubricating oil is routinely re-refined under common business practice, instead of being combusted. The most recent available industry data indicate that 13.6% of collected used oil in North America is re-refined to base oil. Given the low adoption rate for used oil re-refining, a project activity meeting the requirements of this methodology is deemed additional.

5 QUANTIFICATION OF GHG EMISSION REDUCTIONS

Quantification of emission reductions requires calculation of baseline emissions and project emissions.

5.1 BASELINE EMISSIONS

Baseline emissions (BE) must be estimated by using Equation 1 and by summing the baseline emissions for all SSRs identified as included in the baseline in Table 1. Baseline emissions are from the combustion of used lubricating oil that would be avoided by additional production of re-refined used lubricating oil.

Default values for the parameters needed to calculate baseline emissions are listed in Table 2.

Table 2: Default Values for Baseline Emissions

PARAMETER (EQUATION #)	VALUE	SOURCE
Volumetric Heat Content of Lubricant Oil (Eq 1) HC_v	0.0402 GJ/L	IPCC (2006)[6], Table 1. 2
Carbon content of lubricant oil on heating value basis (Eq 1) CC_{LO}	20 kg/GJ	IPCC (2006), Table 1.3

The GHG emissions from combustion of used lubricating oil that would be avoided by additional production of re-refined lubricating oil can be calculated in the following equation:

Equation 1: Total Baseline Emissions

$$BE_t = (HC_{LO_t} \times \frac{CC_{LO}}{1,000}) \times (\frac{44}{12})$$

WHERE

[6] IPCC (2006) Guidelines for National Greenhouse Gas Inventories, Volumes 1 (Introduction) and 2 (Energy)

BE_t	Baseline emissions from the combustion of used lubricating oil that are avoided through re-refining during the reporting period, t (tCO_2)
HC_{LO_t}	Heat content of lubricant that would have been combusted in the baseline during reporting period, t (GJ)
CC_{LO}	Carbon content of lubricant oil on heating value basis – see Table 3 (kg/GJ)
$1,000$	Conversion from kilograms to metric tons
$\frac{44}{12}$	Ratio of molecular weight of CO_2 to carbon

WITH

$$HC_{LO_t} = (HC_v \times (Q_{LO_t} - HBP_{LO}) \times 3.78541)$$

WHERE

HC_{LO_t}	Heat content of lubricant that would have been combusted in the baseline during reporting period, t (GJ)
Q_{LO_t}	Total quantity of used lubricating oil that is re-refined to base oil[7] in reporting period, t (Gallons)
HBP_{LO}	Historic baseline production of used lubricating oil that is re-refined to base oil (Gallons)[8]
HC_v	Volumetric heat content of lubricant oil – see Table 3 (GJ/L)
3.78541	Conversion from gallons to liters

5.2 PROJECT EMISSIONS

Project emissions are determined from energy requirements and emissions from the Project Site (i.e., the facility conducting re-refining).

[7] This quantity shall only include the gallons of re-refined base oil and not the volume of other re-refined products that may be produced in the re-refining process.

[8] See Table 3 for applicability

Equation 2: Total Project Emissions

$$PE_t = PE_{elec,t} + PE_{ff,t}$$

WHERE

PE_t	Project emissions in reporting period, t (tCO_2)
$PE_{elec,t}$	Project emissions from the use of electricity at the refining facility during reporting period, t (tCO_2)
$PE_{ff,t}$	Project emissions from the combustion of fossil fuels used at the refining facility during reporting period, t (tCO_2)

Equation 3: Project Emissions from the Use of Electricity at the Refining Facility

$$PE_{elec,t} = Q_{elec_t} \times \frac{EF_{EL}}{2,204.62}$$

WHERE

$PE_{elec,t}$	Project emissions from the use of electricity at the refining facility during reporting period, t (tCO_2)
Q_{elec_t}	Quantity of electricity used by the refining facility in reporting period, t (MWh)
EF_{EL}	Carbon emission factor for grid electricity[9] ($lbCO_2$/MWh)
$2,204.62$	$lbCO_2/tCO_2$

Equation 4: Project Emissions from the Combustion of Fossil Fuels Used at the Refining Facility

$$PE_{ff,t} = \sum_y \frac{(FF_{y_t} \times EF_y)}{1,000}$$

WHERE

[9] Project proponents shall use the current version of the U.S. Environmental Protection Agency's Power Profiler (http://oaspub.epa.gov/powpro/ept_pack.charts) to determine what regional emission factor should be used in accordance with the Emissions & Generation Resource Integrated Database (eGRID) for EF_{EL}. eGRID emission factors are available at http://www.epa.gov/energy/egrid.

$PE_{ff,t}$	Project emissions from the combustion of fossil fuels used for the refining facility during reporting period, t (tCO_2)
FF_{y_t}	Total quantity of fossil fuel, y, consumed in reporting period, t (Volume/mass of fuel)
EF_y	Fuel specific emission factor for fuel, y[10] (kg CO_2/volume or mass of fuel)
$1,000$	Conversion from kilograms to metric tons

5.3 LEAKAGE

In GHG project literature, leakage is a term that refers to secondary effects where the GHG emission reductions of a project may be negated by shifts in market activity or shifts in materials, infrastructure, or other physical assets associated with the project. In cases where leakage occurs, it must be accounted for and subtracted from the reported net GHG emission reductions for the reporting period.

5.3.1 Market Shifting Leakage Emissions

GHG emissions from the fossil fuel sources required to provide heat and power in place of the used lubricating oil which is re-refined as part of the project must be quantified. This is due to the fact that the heat and power previously produced through the combustion of lubricating oils continues to be produced in the project scenario. However, due to increased re-refining, lubricating oils are not available to produce the heat and power in the same supply in the project scenario as they are in the baseline scenario. Given the smaller supply of lubricating oils, alternative fuels are combusted to produce heat and power and therefore market shifting leakage emissions need to be considered.

5.3.2 Activity Shifting Leakage Emissions

It is not expected that the production of re-refined oils will result in increased emissions due to activity shifting outside of the project boundary and, therefore, activity shifting leakage emissions can be disregarded.

Equation 5: Market Shifting Leakage Emissions

[10] See Table 4 - Appendix C.

$$\mathbf{LE_t = \frac{HC_{LO_t} \times CC_{FF}}{1,000} \times \frac{44}{12}}$$

WHERE

$\mathbf{LE_t}$	Leakage emissions from the combustion of fossil fuels burned to produce heat previously produced with used lubricating oil, in reporting period, $\mathbf{t}$ (tCO_2)
$\mathbf{HC_{LO_t}}$	Heat content of lubricant that would have been combusted in the baseline during reporting period, $\mathbf{t}$ (GJ)
$\mathbf{CC_{FF}}$	Integrated carbon content of replacement fossil fuels on heating value basis[11] (18.867 kg/GJ)
$\mathbf{1,000}$	Conversion from kilograms to metric tons
$\mathbf{\frac{44}{12}}$	Ratio of molecular weight of CO_2 to carbon

5.4 TOTAL EMISSION REDUCTIONS

GHG emission reductions (ER) from a used lubricating oil re-refining project are quantified by subtracting the project emissions (PE_t) and leakage emissions (LE_t) from the baseline emissions (BE_t) as shown in Equation 6.

Equation 6: Total Emission Reductions

$$\mathbf{ER_t = BE_t - PE_t - LE_t}$$

WHERE

$\mathbf{ER_t}$	Total quantity of GHG emission reductions during the reporting period, $\mathbf{t}$ (tCO_2)
$\mathbf{BE_t}$	Total quantity of baseline emissions during the reporting period, $\mathbf{t}$ (tCO_2)
$\mathbf{PE_t}$	Total quantity of project emissions during the reporting period, $\mathbf{t}$ (tCO_2)
$\mathbf{LE_t}$	Leakage emissions from the combustion of fossil fuels burned to produce heat and power previously produced with used lubricating oil, in reporting period, $\mathbf{t}$ (tCO_2)

[11] See Appendix C for derivation of the integrated carbon content factor.

6 MONITORING AND DATA COLLECTION

Each project shall include a monitoring, reporting and verification plan sufficient to meet the requirements of the ACR Standard. The plan shall collect all data required to be monitored in a manner that meets the requirements for accuracy and precision of this Methodology.

6.1 DESCRIPTION OF THE MONITORING PLAN

The project proponent must prepare a monitoring plan describing (for each separately) the following: a) project implementation; b) technical description of the monitoring task; c) data to be monitored and collected; d) overview of data collection procedure; e) frequency of the monitoring; f) quality control and quality assurance procedure; g) data archiving; and h) organization and responsibilities of the parties involved in all the above.

The rationale of monitoring project implementation is to document all project activities implemented by the project that could cause an increase in GHG emissions compared to the baseline scenario.

6.2 DATA COLLECTION AND PARAMETERS TO BE MONITORED

For a specific quantity of used lubricating oil that is re-refined, the process for monitoring the emission reduction parameters includes:

- Documentation of the point of origin of the used lubricating oil including location, volume, and date of collection;
- Documentation of the delivery of used lubricating oil to the re-refining facility, including location, volume, and date of delivery;
- Documentation demonstrating that the used lubricating oil collected and delivered to the Project Site is well-mixed prior to entering the re-refining process to ensure uniform composition;
- Documentation demonstrating that the used lubricating oil received at the Project Site to undergo the re-refining process is tested and meets all required specifications of used lubricating oil suitable for reprocessing based on the technical capabilities of the Project Site;
- Documentation on the volume of re-refined lubricating oil that is produced;

- Documentation of the annual yield of re-refined lubricating oil[12];
- Documentation of the location where the re-refined lubricating oil is produced;
- Documentation demonstrating the Project Proponent's license to operate as a re-refiner;
- In regions where used oil is considered to be hazardous waste, documentation must be maintained to prove proper handling, processing, and disposal of contaminants and waste.

Table 3: Parameters to be Monitored

PARA-METER	DESCRIPTION	DATA UNIT	CALCU-LATED (C), MEASURED (M), REFER-ENCE (R), OPERATING RECORDS (O)	MEASUREMENT FREQUENCY	COMMENT
$Q_{LO,t}$,	Total quantity of lubricating oil that is re-refined to base oil in report-ing period, t	Gallons	M, O	Continuous and per reporting period	On-site pro-duction records
HBP_{LO}	Historic baseline production of used lubricating oil that is re-re-fined to base oil (Gallons)	Gallons	M, O	Determined once and rec-orded	This value shall only be applied by Project Sites that have been produc-ing re-refined lubricating oil for greater than 10 years (at the time of the Project Start Date) and while the methodology

[12] As stated above, this volume only includes the volume of re-refined base oil and not volumes of other re-refined products that may be produced.

PARA-METER	DESCRIPTION	DATA UNIT	CALCU-LATED (C), MEASURED (M), REFER-ENCE (R), OPERATING RECORDS (O)	MEASUREMENT FREQUENCY	COMMENT
					is considered "newly ap-proved"[13]. This value shall be the highest an-nual produc-tion of re-re-fined base oil selected from one of the 3 years preced-ing the Pro-ject Start date.
$Q_{elec,t}$	Quantity of elec-tricity used by the refining facility in reporting period, t	MWh	M, O	Continuous	On-site records from utility bills
EF_{EL}	Carbon emission factor for grid electricity	$lbCO_2$/ MWh	R	Annual value determined once and recorded	See footnote 8
$FF_{y,t}$	Total quantity of fossil fuel, y, consumed in re-porting period, t	Volume or mass	M, O	Continuous or as delivered	On-site records from utility bills or fuel purchase records

[13] See ACR standard for definition of "newly approved"

PARA-METER	DESCRIPTION	DATA UNIT	CALCU-LATED (C), MEASURED (M), REFER-ENCE (R), OPERATING RECORDS (O)	MEASUREMENT FREQUENCY	COMMENT
EF_y	Fuel specific emission factor for fuel, y	kg CO_2/ volume or mass of fuel	R	Annual value determined once and recorded	See Table 4 - Appendix C

7 VERIFICATION

See the ACR Standard for guidance on project validation and verification requirements.

DEFINITIONS

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry (ACR) Standard apply.

American Petroleum Institute	Organization which sets quality and performance standards for base oil and finished lubricants.
Base oil	A lubrication-grade hydrocarbon initially produced from refining crude oil or chemical synthesis that is then mixed with additive packages to produce finished lubricant products. The API grades base oils based on the oil characteristics, including: Group I base stocks contain less than 90 percent saturates and/or greater than .03 percent sulfur and have viscosity index greater than or equal to 80 and less than 120; Group II has base stock that contains greater than or equal to 90 percent saturates and less than or equal to .03 percent sulfur and have viscosity index greater than or equal to 80 and less than 120; Group III base stocks contain greater than or equal to 90 percent saturates and less than or equal to .03 percent sulfur and have viscosity index greater than or equal to 120; Group IV base stocks are polyalphaolefins (PAO) – true synthetic lubricants, made through a process called synthesizing. They have a much broader temperature range, a higher shear strength, and are less prone to oxidation at higher operating temperatures; Group V base stocks include all other base stocks not included in the I, II, III, IV API base oil groups. These include silicone, phosphate ester, polyalkylene glycol (PAG), polyolester, biolubes, etc.
Contaminants	Heavy metals, solvents, and particulate matter which are collected throughout the use phase of a lubricating oil.
GHG Source, Sink, or Reservoir	• **GHG Source:** Physical unit or process that releases a GHG into the atmosphere. • **GHG Sink:** Physical unit or process that removes a GHG from the atmosphere. • **GHG Reservoir:** Physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store or accumulate a GHG removed from the atmosphere by a GHG sink or captured from a GHG source.

Lubricating oil	A petroleum-derived or synthetic crankcase oil, engine oil, hydraulic fluid, transmission fluid, gear oil, heat transfer fluid, or other oil or fluid used for lubricating machinery or equipment.
Mineral base oil	Base oil produced from the refining of crude oil.
Project Site/ Re-refinery	A facility capable of re-processing used lubricating oil and producing base oil that will meet the same rigid quality assurance/quality control standards required as referenced in API Standard Publication 1509 (Fifteenth Edition).
Re-refined lubricating oil	Lubricating oil that is completely treated to the point that it has the same characteristics, functionality and life span as virgin lubricating oil. Re-refined oil meets the quality and technical performance standards for base oil per API standards.
Synthetic base oil	Base oil that is produced from chemical synthesis. Group III base oils are mineral-based but are sometimes classified as synthetic based on additional chemical processing steps. Group IV base oils are produced from the synthesis of polymers.
Used lubricating oil	Lubricating oil which has been used in various applications including automotive, manufacturing, etc. and is collected; the input to the re-refining process.
Virgin base oil	Base oil that is newly produced from either crude refining or chemical synthesis – as opposed to being re-refined – and that has not yet been combined with additives to formulate finished lubricant products.
Virgin lubricating oil	Finished lubricant products that are formulated using virgin base oil and additives.
Volatile Organic Compound	An organic chemical compound whose composition makes it possible for it to evaporate under normal indoor atmospheric conditions of temperature and pressure.

APPENDIX A: BASELINE DATA INPUTS AND CONVERSIONS

In calculating baseline emissions, default values for the volumetric heat content of lubricants and the carbon content of lubricants on a heating value basis are used in Equation 1 and listed in Table 2. The default values in this Methodology for these two parameters are derived or taken from values listed in the IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 2006) as follows:

A.1 VOLUMETRIC HEAT CONTENT FOR LUBRICANTS

IPCC Default Value: 40.2 TJ/Gg (Table 1.2; IPCC, 2006)

Converted into .0402 GJ/L using the following standard conversion factor:

- 1.0 kg lubricant per liter lubricant (Default value for average density of lubricant at room temperature and standard atmospheric pressure, from Table 2, CDP Guidelines for Conversion of Fuel Data (CDP, 2014))

A.2 DEFAULT CARBON CONTENT OF LUBRICATING OIL ON A HEATING VALUE BASIS

IPCC Default Value: 20 kg /GJ (Table 1.3; IPCC, 2006)

APPENDIX B: CALCULATION OF USED OIL AND RE-REFINED LUBRICANTS IN NORTH AMERICA[14]

USED OIL AVAILABLE FOR COLLECTION = Used Oil Generated × Collectable Used Oil

= 9,295 kt. × 0.66%

= 6,134 kt.

$$\textbf{BASE OIL RE-REFINED AS \% OF TOTAL USED OIL AVAILABLE} = \frac{\text{Re-refined Base Stock}}{\text{Used Oil Available for Collection}}$$

= 833 kt. / 6,134 kt.

= 13.6%

[14] All data is from Figure 3E-7 of Kline Report "Global Used Oil Markets and Re-Refined Lubricants 2015: Market Analysis and Opportunities – North America"), Kline &Company (2016), and the 2012 Kline/CalRecycle Report "Lubricant Consumption and Used Oil Generation in California: A Segmented Market Analysis"), Kline & Company (2012).

APPENDIX C: PROJECT AND LEAKAGE EMISSION DATA INPUTS

C.1 PROJECT EMISSIONS FROM COMBUSTION OF FOSSIL FUELS FOR RE-REFINING USED LUBRICATING OIL

To calculate PE_{ff}, project proponents shall use the below emission factors for EF_y which will be revised periodically based on updated information.

Table 4: Fossil Fuel Emission Factors

	CO_2 EF_y	
FOSSIL FUEL TYPE	KILOGRAMS (KG) CO_2	PER UNIT
Propane	5.76	Gallon
Butane	6.71	Gallon
Butane/Propane Mix	6.21	Gallon
Home Heating and Diesel Fuel	10.16	Gallon
Kerosene	9.75	Gallon
Coal (All types)	2,100.82	Short ton
Natural Gas	53.12	Thousand cubic feet
Gasoline	8.89	Gallon
Residual Heating Fuel (Businesses only)	11.79	Gallon
Flared natural gas	54.75	Thousand cubic feet
Petroleum coke	14.70	Gallon

	CO_2 EF_y	
Other petroleum & miscellaneous	10.02	Gallon
Source: U.S. Energy Information Administration, published February 2, 2016.		

C.2 MARKET-SHIFTING LEAKAGE: INTEGRATED CARBON CONTENT OF REPLACEMENT FOSSIL FUELS DEFAULT VALUE

Based on a lifecycle assessment done for CalRecycle by the University of California at Santa Barbara (UCSB) (2013)[15], this Methodology assumes that an even mix of three primary fuels will replace used lubricating oil — No. 2 distillate, No. 6 residual oil, and natural gas. Given this mix, it was necessary to derive a default integrated carbon content for these replacement fuels. Per the UCSB life cycle analysis, each of these fuels should be weighted equally for replacement purposes. The carbon content of each fuel was taken from Table 1.3 of IPCC 2006. The integrated carbon content factor is a simple weighted average of the carbon content of each fuel.

Table 5: Integrated Carbon Content of Replacement Fossil Fuels

FUEL	DISPLACEMENT RATE*	CARBON CONTENT ON HEATING VALUE BASIS $KGCO_2/GJ$
No. 2 Distillate	0.33	20.20
No. 6 Residual Oil	0.33	21.10
Natural Gas	0.33	15.30
Integrated Carbon Content of Replacement Fossil Fuels		18.867

[15] Life Cycle Assessment of Used Oil Management in California. Pursuant to Senate Bill 546 (Lowenthal), R. Geyer et al. CalRecycle, July 29, 2013

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LANDFILL GAS DESTRUCTION AND BENEFICIAL USE PROJECTS

VERSION 1.0

March 2017

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

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ACKNOWLEDGEMENTS

The Methodology was developed by ACR with technical support from the US EPA's Landfill Methane Outreach Program (LMOP).

ACRONYMS

CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
Offsets	Carbon Offset Credits
CAA	Clean Air Act
CNG	Compressed Natural Gas
ERT	Emission Reduction Tonne
GCCS	Gas Collection and Control System
SSR	GHG Source, Sink, or Reservoir
GWP	Global Warming Potential
LFG	Landfill Gas
LFGTE	Landfill Gas-to-Energy
LNG	Liquefied Natural Gas
CH_4	Methane
MSW	Municipal Solid Waste Landfill
NMOC	Non-Methane Organic Compound
NSPS	New Source Performance Standard
RCRA	Resource Conservation & Recovery Act
WIP	Waste in Place

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1. BACKGROUND AND APPLICABILITY

1.1 SUMMARY DESCRIPTION OF THE METHODOLOGY

Table 1: Eligible LFG Activities

Project Activity	Description
Destruction in a flare	Burning LFG onsite in an open or an enclosed flare.
Landfill gas to energy	Converting LFG in an engine, turbine or boiler to energy to be used on- or off-site.
Natural gas pipeline injection	Processing of LFG for injection into a natural gas pipeline.

The collection and combustion of landfill gas (LFG) is an effective method for decreasing the greenhouse gas (GHG) emissions from landfills that would have otherwise been vented to the atmosphere. This Methodology provides the quantification and accounting frameworks, including eligibility and monitoring requirements, for the creation of carbon offset credits from the reductions in GHG emissions resulting from the destruction or utilization of landfill gas at eligible landfills. The Methodology is intended to be used as an incentive to increase these activities and utilizes a flexible additionality framework which is based on either a performance standard or ACR's three-prong additionality test, as stipulated in Section 3.

1.2 APPLICABILITY CONDITIONS

Projects that reduce methane emissions as a result of the combustion or beneficial use of landfill gas in any of the following activities are considered a "project activity" under this Methodology:

- The destruction of landfill gas in an open or closed flare;
- The conversion of landfill gas in a turbine, boiler or generator to energy;
- The enhancement of landfill gas for injection into a natural gas pipeline; and
- The enhancement of landfill gas for use in fleet vehicles, trucks and cars.

In addition to satisfying the latest ACR program eligibility requirements as found in the *ACR Standard*, project activities must satisfy the following conditions for this Methodology to be applicable:

- The project is located in the United States; and
- The project is not required by any regulatory agency.

1.3 START DATE

The Start Date is the date that the landfill gas project became operational. For purposes of this Methodology, a project is considered to be operational when methane is continuously destroyed following a start-up period which may be a maximum of 6 months after the date of project commissioning. Project commissioning is the first day which the GCCS and respective destruction device(s) are fully operational and either destroying or enhancing landfill gas.

1.4 CREDITING PERIOD

A Crediting Period is the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. The crediting period for a project activity shall be ten years.

Projects that have previously generated carbon offsets in a GHG Program other than ACR and whose crediting period has expired may apply for a new crediting period under the ACR program. As with all projects, the requirements of this Methodology must be met and the project must receive a positive validation opinion.

1.5 REPORTING PERIOD

A Reporting Period is the portion of time during the crediting period for which the project is reporting emission reductions to be verified and issued. Reporting periods shall not exceed five (5) years.

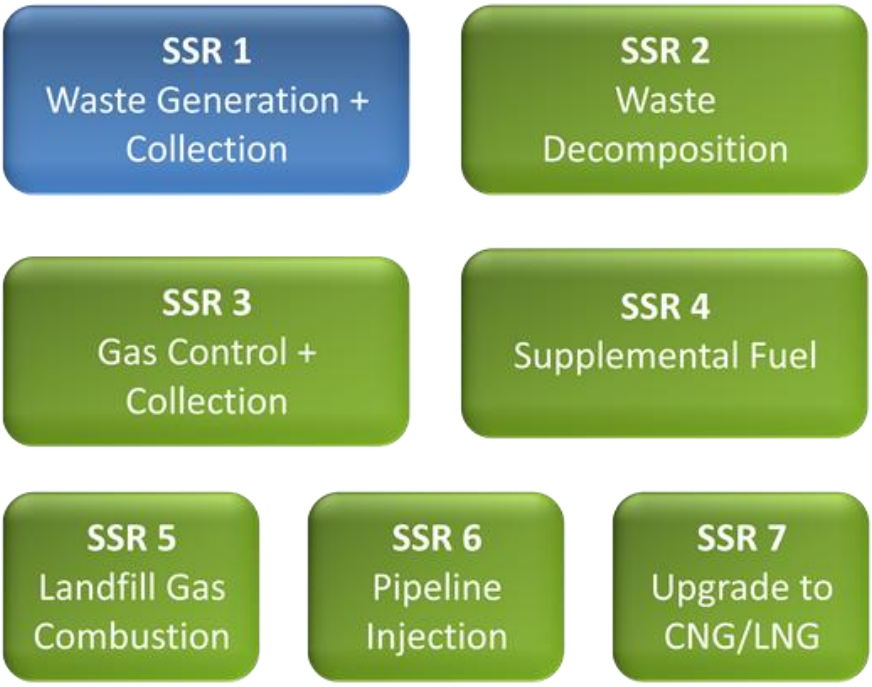
1.6 PERIODIC REVIEWS AND REVISIONS

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project's activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the Methodology.

2. PROJECT BOUNDARIES

2.1 GEOGRAPHIC BOUNDARY

Figure 1: Project Boundary Diagram for Landfill Gas Projects



The Blue SSR represents emission sources outside of the project boundary while the green SSRs are those included in the project boundary. Within the boundaries, the sources of GHG emissions and removals are from the waste decomposition, landfill gas collection and control system, the maintenance or operations of the destruction or combustion device(s), and any emissions associated with the enhancement of LFG. Table 2 lists the GHG sources included and excluded depending on whether the sources are within or outside project boundaries.

Table 2: Greenhouse Gases and Sources

SSR		Source Description	Gas	Included (I) Or Excluded (E)	Comments
1	Waste Generation & Collection	Emissions from the generation and hauling of waste to the landfill	CO_2	E	Emissions resulting from this SSR should be equivalent in both the project and baseline scenarios.
			CH_4	E	
			N_2O	E	
2	Waste Decomposition	Emissions from the decomposition of waste at the landfill	CO_2	E	Emissions are assumed to be de minimis.
			CH_4	I	Primary GHG affected by the project.
			N_2O	E	Emissions are assumed to be de minimis.
3	Gas Collection & Control	Emissions associated with the energy consumed to collect and process LFG	CO_2	I	Emissions resulting from the GCCS shall be included.
			CH_4	E	Emissions are assumed to be de minimis.
			N_2O	E	
4	Supplemental fuel	Combustion of fossil fuels to supplement the destruction or use of LFG	CO_2	I	Emissions resulting from the use of supplemental fuel shall be included.
			CH_4	I	
			N_2O	E	Emissions are assumed to be de minimis.
5	Landfill Gas Combustion	The combustion of LFG in an eligible destruction device	CO_2	E	Emissions are assumed to be de minimis.
			CH_4	I	Emissions resulting from the incomplete combustion of LFG shall be included.
			N_2O	E	Emissions are assumed to be de minimis.
6	Pipeline Injection	The enhancement of LFG to be injected into a natural gas pipeline	CO_2	I	Emissions resulting from the enhancement of LFG shall be included.
			CH_4	I	
			N_2O	E	Emissions are assumed to be de minimis.
7	CNG/LNG Upgrade	The enhancement of LFG to be used in fleet vehicles, trucks or cars.	CO_2	I	Emissions resulting from the enhancement of LFG shall be included.
			CH_4	E	Emissions are assumed to be de minimis.
			N_2O	E	

3. BASELINE DETERMINATION AND ADDITIONALITY

3.1 BASELINE DETERMINATION

The baseline for a project activity is determined utilizing industry standards and represents the most commonly used practices and technologies. Landfill gas destruction and beneficial use projects are not eligible to generate Emission Reduction Tons (ERT) in instances where the collection and destruction of landfill gas can be considered a standard business practice or is required by law or as a result of any other legally binding framework. The baseline determination shall be consistent with the pre-project activity prior to the start date.

For projects that are or have previously employed ineligible project activities, such as a passive flare, or have an eligible project activity that was implemented prior to the specified start date, emission reductions associated with these activities shall be accounted for in the baseline emission calculations. Project proponents shall submit a proposed method for quantifying pre-project emission reductions to ACR for approval. Emission reductions resulting from ineligible project activities shall be accounted for in Equation 2 as NE_{device}.

3.2 ADDITIONALITY ASSESSMENT

Emission reductions from the project must be additional, or deemed not to occur in the "business-as usual" scenario. Assessment of the additionality of a project will be made based on passing a practice-based performance standard and a regulatory surplus test OR ACR's three-prong additionality test (which, as a first step, includes a regulatory surplus test).

Projects shall demonstrate conformance with the full requirements found in Section 3.2.1 OR 3.2.2 only once at the beginning of a crediting period. However, projects shall demonstrate regulatory surplus during verification activities for each reporting period. For more information on the development of the practice-based performance standard, please see Appendix A.

3.2.1 Practice-Based Performance Standard

Projects with the characteristics described below may apply the practice-based performance standard to demonstrate that the project activity is not common practice and is therefore considered additional pending the outcome of the regulatory surplus test:

- Project activities located in non-arid counties (defined as counties with more than 25 inches of precipitation historically) implemented at landfills with equal to or less than 500,000 tons of waste in place; or

- Project activities located in arid counties (defined as counties with less than 25 inches of precipitation historically) implemented at landfills with equal to or less than 1,500,000 tons of waste in place.

Appendix A shall be used to determine if a project is located in a non-arid or arid county.

3.2.1.1 Regulatory Surplus Test

For projects applying the performance standard discussed in Section 3.2.1, a regulatory surplus test shall also be applied. To pass the regulatory surplus test, a project must not be mandated by existing laws, regulations, statutes, legal rulings, or any other regulatory frameworks that directly or indirectly affect the GHG emissions associated with a project such as the CAA or RCRA. The project proponent must demonstrate that there is no existing law, regulation, statute, legal ruling, or other regulatory framework that mandates the project or effectively requires the GHG emission reductions associated with the installation of a destruction device or the infrastructure necessary for enhancing the landfill gas.

The project proponent shall provide evidence including all supporting documentation necessary to prove that landfill gas destruction, abatement or mitigation is not required.

3.2.2 ACR's Three-Prong Additionality Test

For project activities that do not automatically qualify under the practice-based performance standard outlined in Section 3.2.1, ACR's Three-Prong additionality test shall be applied. The first step in the Three-Prong additionality test, as stated above, is the application of a regulatory surplus test which is followed by a common practice assessment and description of implementation barriers. Landfill gas projects may only demonstrate a financial implementation barrier(s) and may not apply technological or institutional barriers. For a complete description of the ACR Three-Prong Additionality Test, please refer to the ACR Standard.

4. QUANTIFICATION OF GHG EMISSION REDUCTIONS

Quantification of project emission reductions requires calculation of baseline emissions and project emissions.

4.1 BASELINE EMISSIONS

Equation 1: Volume of CH_4 Combusted

This is the amount of GHG emissions that would take place without the destruction or beneficial use of the landfill gas. Records of continuous landfill gas flows (in standard cubic feet per minute) shall be matched with continuous methane content data using Equation 1:

$$\mathbf{CH_{4combusted}} = [(\mathbf{LFG_{captured}} * \%\mathbf{CH_{4,continuous}}) + (\mathbf{LFG_{captured}} * \%\mathbf{CH_{4,weekly}} * (\mathbf{1} - \mathbf{DF_{weekly}}))] * (\mathbf{1} - \mathbf{OF})$$

WHERE

$\mathbf{CH_{4combusted}}$	Total volume of methane combusted (scf)
$\mathbf{LFG_{captured}}$	LFG captured (scf)
$\mathbf{\%CH_{4,\ continuous}}$	Methane content of LFG for continuous methane monitoring (%)
$\mathbf{\%CH_{4,\ weekly}}$	Methane content LFG for duration weekly methane monitoring (%)
$\mathbf{DF_{weekly}}$	Discount factor for weekly methane content monitoring (a value of 0.1 shall be applied only when weekly readings occurred)
$\mathbf{OF}$	Oxidation factor

The oxidation factor is based on the recommended oxidation rates by the U.S. EPA. The following values shall be applied based on the type of landfill cover and methane flux within the project boundary:

- A value of 0.0 shall be applied to landfills with a synthetic cover;
- A value of 0.10 shall be applied to landfills without a synthetic cover that are not required to determine methane flux or for landfills that do not have a soil cover of at least 24 inches for the majority of landfill area containing waste;

- A value of 0.35 shall be applied to landfills have a soil cover of at least 24 inches for a majority of the landfill area containing waste and for which the methane flux rate is less than 10 grams per square meter per day ($g/m^2/d$);
- A value of 0.25 shall be applied to landfills have a soil cover of at least 24 inches for a majority of the landfill area containing waste and for which the methane flux rate is 10 - 70 grams per square meter per day ($g/m^2/d$); or
- A value of 0.10 shall be applied to landfills have a soil cover of at least 24 inches for a majority of the landfill area containing waste and for which the methane flux rate is greater than 70 grams per square meter per day ($g/m^2/d$).

Equation 2: Net Mass of CH_4 Destroyed

In order to estimate the amount of methane combusted in metric tons, methane combusted needs to be converted to weight using Equation 2:

$$\mathbf{CH_{4total}} = \left(\left((\mathbf{CH_{4combusted}} * \mathbf{CF}) * \mathbf{16.04} * \left[\frac{1}{10^6}\right] * \left[\frac{1}{24.04}\right] * \mathbf{28.32}\right) * \mathbf{95\%}\right) - \mathbf{NE_{device}}$$

WHERE

$\mathbf{CH_{4total}}$	Total methane combusted (metric tons)
$\mathbf{CH_{4combusted}}$	Methane combusted (scf – as calculated in Equation 1)
CF	Correction factor – calculated per Equation 3[1]
16.04	Molecular weight of CH_4
$\mathbf{1/10^6}$	Conversion to metric tons (MT/g)
1/24.04	Gas constant (mol/L – measured at standard temperature and pressure – defined as 68ºF and 14.7psi)
28.32	Conversion factor (L/cf)
95%	Destruction efficiency of the destruction device[2]
$\mathbf{NE_{device}}$	Emissions from a pre-project, non-eligible device

[1] The correction factor shall only be applied in instances where the project flow meter does not use a standard temperature of 68ºF. Where project flow meters do apply a standard temperature of 68ºF, CF = 1.

[2] In lieu of the default 95% destruction efficiency, project proponents may apply the results of a third-party source test conducted by an organization meeting or exceeding the U.S. Environmental Protection Agency's *Minimum Competency Requirements for Air Emission Testing* rule to determine the actual destruction efficiency of the device.

Equation 3: Correcting LFG Flow Temperature

If the monitoring equipment is set to record landfill gas flow at a temperature other than that defined in Equation 2 (68ºF), the project proponent must normalize the landfill gas flow by using the correction factor calculated in Equation 3:

$$CF = \frac{527.67}{T + 459.67}$$

WHERE

CF	Correction factor
T	Temperature as measured by project flow meters

4.2 PROJECT EMISSIONS

Depending on project-specific circumstances, certain emissions sources shall be subtracted from total project emission reductions using the equations below.

Equation 4a: CO_2 Emissions from Fossil Fuel Combustion

$$\mathbf{Dest_{CO2}} = \sum \mathbf{y} \left(\mathbf{FF_y} * \mathbf{EF_y} \right)$$

WHERE

$\mathbf{Dest_{CO2}}$	CO_2 emissions from fossil fuel used in methane destruction process (tCO_2)
$\mathbf{FF_y}$	Total quantity of fossil fuel,y, consumed (volume of fuel)
$\mathbf{EF_y}$	Fuel specific emission factor for fuel, y (tCO_2/fuel quantity) – See Appendix B

Equation 4b: CO_2 Emissions from Project Specific Electricity Consumption

$$\mathbf{Elec_{CO2}} = \frac{\mathbf{EL_{total}} * \mathbf{EF_{EL}}}{2204.62}$$

WHERE

$\mathbf{Elec_{CO2}}$	Project specific electricity emissions (tCO_2)
$\mathbf{EL_{total}}$	Total grid connected electricity consumption (MWh)
$\mathbf{EF_{EL}}$	Carbon emission factor for grid electricity ($lbCO_2$/MWh) - See Appendix B
2204.62	$lbCO_2/tCO_2$

Equation 5: Project Emissions

$$\mathbf{PE} = \mathbf{Elec_{CO2}} + \mathbf{Dest_{CO2}}$$

WHERE

PE	Project emissions (tCO_2)
$Elec_{CO2}$	Project specific electricity emissions (tCO_2)
$Dest_{CO2}$	CO_2 emissions from fossil fuel used in methane destruction or transportation process (tCO_2)

4.3 LEAKAGE

Leakage is a term that refers to secondary effects where the GHG emission reductions of a project may be negated by shifts in market activity or shifts in materials, infrastructure, or other physical assets associated with the project. ACR does not expect landfill methane projects to result in any additional activities that would augment GHG emissions outside of the project boundary and, therefore, no leakage assessment is required.

4.4 EMISSION REDUCTIONS

Equation 6: GHG Emission Reductions

$$\boldsymbol{ER = [CH_{4total} * GWP_{CH4}] - PE}$$

WHERE

ER	Total Emission Reductions (tCO_2e)
CH_{4total}	Methane combusted (MT)
GWP_{CH4}	Global warming potential of methane[3]
PE	Project emissions (tCO_2)

[3] Project proponents shall refer to the ACR Program Standard for the approved IPCC GWP for methane value, which will be updated periodically as new information becomes available.

5. MONITORING AND DATA COLLECTION

Each project shall include a GHG project plan sufficient to meet the requirements of the ACR Standard. The plan shall collect all data required to be monitored and in a manner which meets the requirements for accuracy and precision of this Methodology. Project Proponents shall use the template for GHG project plans available at www.americancarbonregistry.org. Additionally, projects are required to submit a GHG monitoring report for each reporting period. Project Proponents shall use the template for GHG monitoring reports available at http://americancarbonregistry.org/carbon-accounting/tools-templates.

5.1 DESCRIPTION OF THE GHG PROJECT PLAN

These are expanded upon in the sections below. The project proponent must prepare a GHG project plan describing (for each separately) the following: a) project implementation; b) technical description of the monitoring task; c) data to be monitored and collected; d) overview of data collection procedures; e) frequency of the monitoring; f) quality control and quality assurance procedures; g) data archiving; and h) organization and responsibilities of the parties involved in all the above.

The rationale of monitoring project implementation is to document all project activities implemented by the project that could cause an increase in GHG emissions compared to the baseline scenario.

5.2 DATA COLLECTION AND PARAMETERS TO BE MONITORED

Project monitoring and recording shall include the following parameters:

- Continuous monitoring of landfill gas flow to each destruction device,
- Methane content analysis using a continuous gas analyzer,
- Electricity production records, if applicable,
- Quantity of transport fuel or pipeline quality gas generated, if applicable,
- Destruction device operating hours, if applicable,
- Before and after results of field checks,
- Project-related emission data (grid electricity consumed and/or fossil fuels used by the project), and
- A GCCS downtime log that includes the duration and cause of a GCCS shutdown or malfunction.

5.2.1 Flow Monitoring

Landfill gas flow shall be continuously monitored using an adequate flow meter. Continuous monitoring is defined as one data point recorded at least every 15 minutes. The flow meter shall be installed along the header pipe at a location that provides a straight section of pipe sufficient to establish laminar gas flow, in order to mitigate any turbulence resulting from bends, obstructions, or constrictions in the pipe. This turbulence may result in inaccurate flow measurements. The flow meter shall be located downstream of the blower and upstream of the destruction device. All flow data used to calculate emission reductions must be corrected for standard temperature (68ºF) and standard pressure (14.7psi).

5.2.2 Methane Content Analysis

The methane fraction in the landfill gas shall be continuously monitored using a methane analyzer. Continuous monitoring is defined as one data point at least every 15 minutes.

Weekly readings may be taken using a handheld gas analyzer for no more than two (2) months with a 10% discount for the duration of the weekly readings if the continuous methane analyzer fails or is being serviced. The discount shall be applied in Equation 1 only for the period in which weekly readings were taken in place of continuous readings. Handheld gas analyzers shall meet the calibration and maintenance requirements of Section 5.2.3.

5.2.3 Monitoring Equipment Calibration/Quality Assurance

The following information regarding flow meter and gas analyzer performance shall be maintained:

- Proof of initial calibration for flow meters and gas analyzers;
- Capability to record flow or methane concentration every 15 minutes;
- Means to correct for temperature and pressure (for flow meter, if necessary); and
- Manufacturer's recommended factory calibration frequency.

It is essential that flow meters and gas analyzers operate properly in order to accurately quantify GHG emission reductions. To ensure proper equipment function, annual field checks for flow meter and methane analyzer accuracy shall be performed by a qualified third-party. Annual field checks must meet the following conditions[4]:

[4] Annual field checks must be separated by an elapsed time frame of a minimum of 10 months from the date of the preceding field check but must not exceed 12 months.

- Field checks must be performed in accordance with manufacturer's specifications and methodologies;
- Field checks must be performed by the manufacturer or other appropriately trained third-party personnel;
- All field checks must be documented and made available for review during the validation and verification process. Documentation must include specific results of the field checks including the percent error demonstrated by the instrumentation capturing the before (as-found) and after (as-left) status;
- Should the instrumentation demonstrate an error in the reading or output of either landfill gas flow or methane content that is greater than or equal to 5%, written documentation must be provided as to the correction applied during the field check and the resulting accuracy of the instrumentation. In situations where the flow meter or methane analyzer percent error is greater than or equal to 5%, all data from the previous field check through to the most recent field check shall be scaled by the percent error documented in the most recent field check.

Projects may choose to conduct more than one field check to ensure that the monitoring equipment continuously meets the requirements of Section 5.2.3. If a project elects to conduct more frequent field checks, they must adhere to the requirements of Section 5.2.3. Additionally, manufacturer specifications regarding instrument calibration shall be followed. No ERTs will be granted for periods where the flow meter or gas analyzer have not been maintained in accordance with manufacturer calibration requirements.

5.2.4 Destruction Device Operating Hours

The operating hours for each destruction device must be monitored to ensure that landfill gas destruction is claimed for landfill gas destroyed only during periods when the device(s) was/were operational. Emission reductions may not be claimed for time periods where the destruction device(s) is not operating or thermocouple readings are below 500 degrees Fahrenheit. Operating hours must be continuously monitored and recorded except for non-flare destruction devices (e.g. boilers or engines) that are equipped with an operable safety shut off valve and that impede the flow of landfill gas to the device when it is not in operation. In general, operating hours for a flare are tracked through the use of a thermocouple which monitors the presence and temperature of the flame. Operating hours for other destruction devices such as engines should be tracked through operator logs, electricity production records, or other verifiable means.

Projects that treat landfill gas and inject it into a natural gas pipeline shall only provide evidence of the quantity of gas delivered to the pipeline and are not required to provide evidence of landfill methane destruction.

5.2.5 Project-Related Emissions

Project-related emissions may result from the used of imported electricity or from the use of fossil fuels. Information related to electricity usage and relevant fossil fuel consumption may be obtained from sources such as on-site electricity meters, utility invoices, and fuel purchase records.

5.2.6 Parameters Monitored

Parameter	CH_4%
Units	Percentage
Description	Percent of methane monitored by the gas analyzer.
Relevant Section	4.1
Relevant Equation(s)	1
Source of Data	Gas analyzer/data acquisition device
Measurement Frequency	Continuous or using a handheld analyzer during calibration.

Parameter	$LFG_{captured}$
Units	scfm
Description	Landfill gas flow as measured by the flow meter.
Relevant Section	4.1
Relevant Equation(s)	1
Source of Data	Flow meter/data acquisition device
Measurement Frequency	Continuous

Parameter	Flare Operating Hours
Units	Degrees Fahrenheit
Description	Monitoring of operational activity of destruction device to ensure destruction of landfill gas. Not applicable for pipeline injection projects.
Relevant Section	4.1
Relevant Equation(s)	1
Source of Data	Thermocouple/data acquisition device
Measurement Frequency	Continuous

Parameter	Flare Temperature
Units	Degrees Fahrenheit
Description	Monitoring of temperature of destruction device to ensure destruction of landfill gas. Not applicable for pipeline injection projects.
Relevant Section	4.1
Relevant Equation(s)	1
Source of Data	Thermocouple/data acquisition device
Measurement Frequency	Continuous

Parameter	FF_y
Units	Volume of fuel
Description	Total quantity of fossil fuel,y, consumed.
Relevant Section	4.1.2
Relevant Equation(s)	4a
Source of Data	Utility or fuel Invoices
Measurement Frequency	Collected annually

Parameter	EL_{total}
Units	MWh
Description	Total grid connected electricity consumption.
Relevant Section	4.1.2
Relevant Equation(s)	4b
Source of Data	Electricity Invoices
Measurement Frequency	Collected annually

DEFINITIONS

If not explicitly defined here, the definitions in the latest version of the American Carbon Registry (ACR) Standard apply.

Clean Air Act	A comprehensive federal law designed to regulate both stationary and mobile air emissions in order to improve air quality and human health.
Compressed Natural Gas	Natural gas under pressure, typically used a fuel substitute.
Gas Collection and Control System	A system of wells and pipes designed to collect landfill gas that can be conveyed under vacuum to a combustion device such as a flare or engine.
Landfill Gas	Landfill gas is a product of the decomposition of organic material contained in municipal solid waste landfills.[5]
Landfill Gas-to-Energy	The process of converting landfill gas to electricity, steam or natural gas for fuel.
Liquefied Natural Gas	Natural gas in a liquid state for ease of use or storage.
Municipal Solid Waste Landfill	A designation for landfills that accept household trash.
Non-Methane Organic Compound	Non-methane organic compounds consist of hazardous air pollutants and volatile organic compounds, which when exposed to sunlight may form ground-level ozone or smog.
New Source Performance Standard	Federal rules for U.S. landfills, codified in 40 CFR Subpart WWW, that govern emissions from existing landfills with a design capacity greater than 2.5 million megagrams that began receiving waste or began construction or made modifications after May 30, 1991.

[5] As defined by the U.S. EPA's Landfill Methane Outreach Project. Found at http://www3.epa.gov/lmop/faq/landfill-gas.html.

APPENDIX A: DEVELOPMENT OF PRACTICE-BASED PERFORMANCE STANDARD

While the total number of landfills in the U.S. has declined over time, the amount of waste sent to landfills has increased. As of 2015, landfills accounted for approximately 18% [6]of anthropogenic methane emissions in the U.S. The Environmental Protection Agency's (EPA) Landfill Methane Outreach Program (LMOP) maintains a database of the 2,434 landfills in the U.S. of which there are approximately 1,000 municipal solid waste (MSW) landfills that are subject to the existing New Source Performance Standards (NSPS). Of the 1,000 MSW landfills subject to NSPS, 574 have installed gas collection and control systems (GCCS) as a result of the regulatory requirement, while the remainder are only required to report their annual emissions to the EPA[7]. Only landfills that have a design capacity of 2.5 million metric tons and 2.5 million cubic meters of waste are subject to federal NSPS requirements and landfills are only required to abate emissions if they are found to reach or surpass the 50 megagrams per year of non-methane organic compounds (NMOC) emission threshold or 34 megagrams per year beginning in 2025.

For landfills that have reached or have exceeded the allowable NMOC emission threshold, no credits may be claimed once the landfill is required to install a GCCS. However, landfills that are not subject to NSPS regulations or have not reached the allowable NMOC threshold may participate in a voluntary carbon offset program.

While past landfill gas carbon offset protocols have been predicated upon a low adoption rate for LFG GCCS *nationally* the number of voluntary landfill gas projects has steadily increased to the point where a national, practice-based performance standard is no longer applicable. However, based on analysis of the LMOP database along with assistance from several state or local permitting authorities, ACR has identified that there are still criteria that define landfills with low penetration rates for voluntary landfill gas projects. ACR began by identifying candidate landfills which consisted of the following criteria:

- Landfills that were currently open or had closed within in the last 5 years;
- Landfills that are currently under the waste in place (WIP) threshold for the region (i.e. arid versus non-arid locations, see Table A1; and
- Landfills that are not subject to NSPS or other state/local requirements to install a GCCS.

[6] EPA's Air Rules for Municipal Solid Waste Landfills, Proposed Emission Guidelines for Existing Landfills: Fact Sheet. Found at http://www3.epa.gov/ttn/atw/landfill/20150814egfs.pdf.

[7] EPA's Air Rules for Municipal Solid Waste Landfills, Proposed Emission Guidelines for Existing Landfills: Fact Sheet. Found at http://www3.epa.gov/ttn/atw/landfill/20150814egfs.pdf.

It should be noted that recently closed landfills may generate enough landfill gas to facilitate a project which is why candidate landfills closed in the last 5 years were included.

Given the above criteria, ACR has calculated that voluntary projects at landfills in non-arid regions (regions with more than 25 inches of rain in the last five years) and less than 500,000 tons of WIP, and at landfills in arid regions (regions with less than or equal to 25 inches of rain in the last five years) with less than 1,500,000 tons of WIP, account for less than 15% of candidate landfills in each region (Table A1)[8]. As these adoption rates are low, landfills that meet the criteria stipulated in Section 3.2.1 automatically qualify under the practice-based performance standard. The historical precipitation map in Figure 2 below shall be used to determine if a project is located in an arid or non-arid region.

Table A1: Penetration Rate of Candidate Landfills

	Non-Arid	Arid
WIP Limit	**500,000**	**1,500,000**
Candidate Landfills	90	92
Candidates Landfills with a Voluntary GCCS	13	12
Percent Adoption	14.44%	13.04%

[8] Precipitation zones defined by the EPA (Section 2.4.4.1). Found at https://www3.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf.

Figure A1: U.S. Historic Precipitation Map

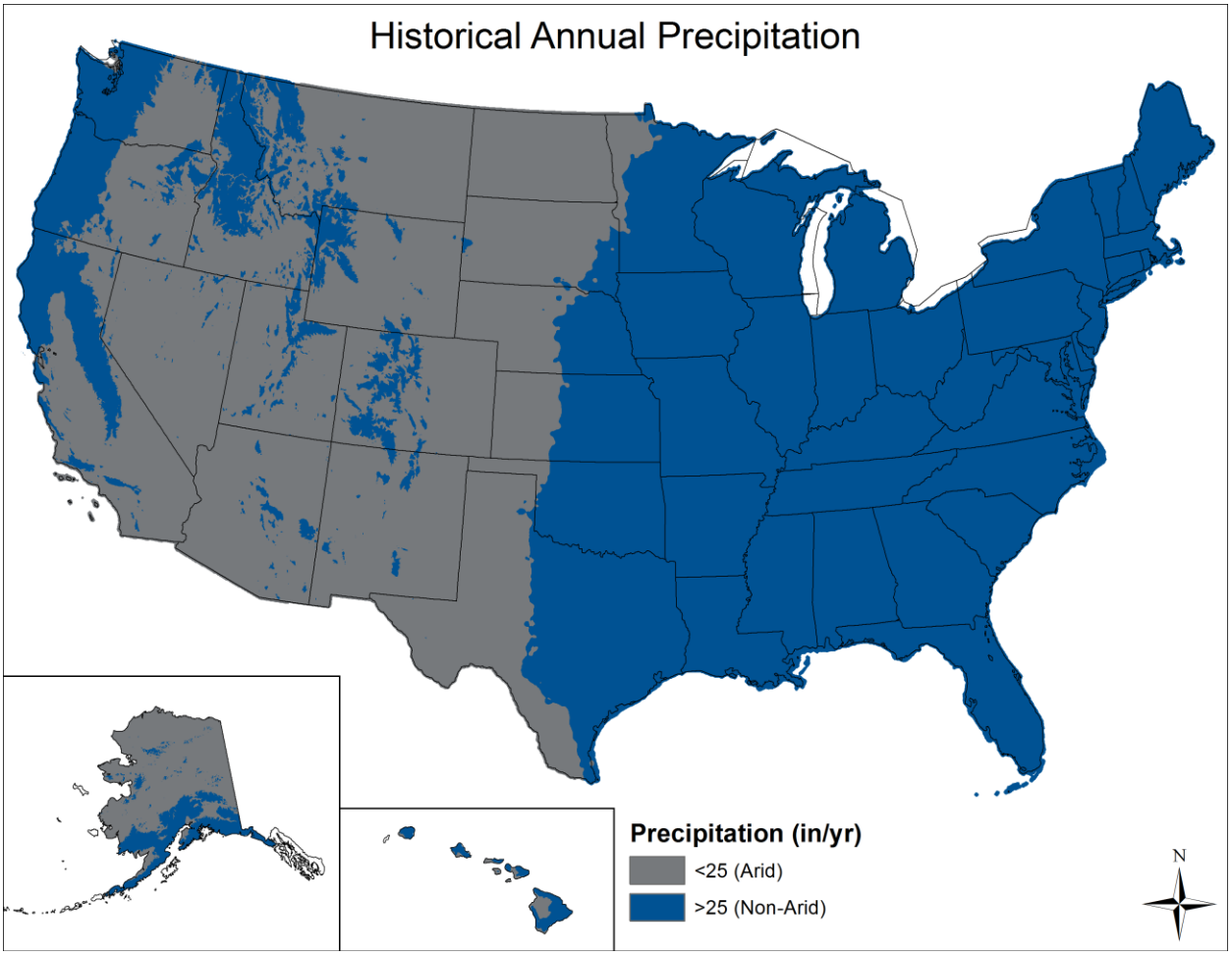


Figure A1 precipitation data sources by region include:

- **Continental U.S.**: PRISM Climate Group, Oregon State University, http://prism.oregonstate.edu, created Feb 4, 2004.
- **Alaska**: Arctic Landscape Conservation Cooperative, 2012. Baseline (1961-1990) average total precipitation (mm) for Alaska and Western Canada. Created by Arctic Landscape Conservation Cooperative staff; data provided by Scenarios Network for Alaska and Arctic Planning. http://arcticlcc.org/products/spatial-data/show/baseline-1961-1990-rasters.
- **Hawaii**: Giambelluca, T.W., Q. Chen, A.G. Frazier, J.P. Price, Y.-L. Chen, P.-S. Chu, J.K. Eischeid, and D.M. Delparte, 2013: Online Rainfall Atlas of Hawai'i. Bull. Amer. Meteor. Soc. 94, 313-316, doi: 10.1175/BAMS-D-11-00228.1.

APPENDIX B: EMISSION FACTORS

Project proponents shall use the current version of the U.S. Environmental Protection Agency's Power Profiler (http://oaspub.epa.gov/powpro/ept_pack.charts) to determine what regional emission factor should be used in accordance with the Emissions & Generation Resource Integrated Database (eGRID) for EF_{EL}. eGRID emission factors are available at http://www.epa.gov/energy/egrid.

To calculate $Dest_{CO2}$, project proponents shall use the below emission factors for EF_y which will be revised periodically based on updated information.

	CO_2 EF_y					
Fossil Fuel Type	**Pounds (lbs.) CO_2**	**Per Unit**	**Kilo-grams (kg) CO_2**	**Per Unit**	**Lbs. CO_2/ MMBtu**	**kg CO_2/ MMBtu**
Gases						
Propane	12.70	Gallon	5.76	Gallon	139.05	63.07
Butane	14.80	Gallon	6.71	Gallon	143.20	64.95
Butane/Propane Mix	13.70	Gallon	6.21	Gallon	141.12	64.01
Home Heating and Diesel Fuel	22.40	Gallon	10.16	Gallon	161.30	73.16
Kerosene	21.50	Gallon	9.75	Gallon	159.40	72.30
Coal (All types)	4,631.50	Short ton	2,100.82	Short ton	210.20	95.35
Natural Gas	117.10	Thousand cubic feet	53.12	Thousand cubic feet	117.00	53.07
Gasoline	19.60	Gallon	8.89	Gallon	157.20	71.30
Residual Heating Fuel (Businesses only)	26.00	Gallon	11.79	Gallon	173.70	78.79
Flared natural gas	120.70	Thousand cubic feet	54.75	Thousand cubic feet	120.60	54.70
Petroleum coke	32.40	Gallon	14.70	Gallon	225.10	102.10
Other petroleum & miscellaneous	22.09	Gallon	10.02	Gallon	160.10	72.62
Coals						
Anthracite	5,685.00	Short ton	2,578.68	Short ton	228.60	103.70
Bituminous	4,931.30	Short ton	2,236.80	Short ton	205.70	93.30
Subbituminous	3,715.90	Short ton	1,685.51	Short ton	214.30	97.20
Lignite	2,791.60	Short ton	1,266.25	Short ton	215.40	97.70
Coke	6,239.68	Short ton	2,830.27	Short ton	251.60	114.12

Source: U.S. Energy Information Administration, published February 2, 2016.

APPENDIX C: REFERENCES

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American Carbon Registry®

Trusted solutions for the carbon market

The American Carbon Registry® Methodology for Reduction in Emissions from the Recycling of Transformer Oil



Version 1.0

February 2014

A nonprofit enterprise of

WINROCK INTERNATIONAL

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This methodology was developed by Hydrodec Group PLC.

The appropriate citation is American Carbon Registry (2014), *American Carbon Registry Methodology for Reduction in Emissions from the Recycling of Transformer Oil*, Version 1.0. Winrock International, Little Rock, Arkansas.



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1: BACKGROUND AND APPLICABILITY

1.1 Introduction

The United States is the largest consumer of energy in the world and consequently millions of gallons of transformer oil reach the end of their useful life each year. Transformer oil (or insulating oil) is a highly refined oil that is stable at high temperatures and has excellent electrical insulating properties. It is used in oil-filled transformers, as well as some types of high-voltage capacitors, switches and circuit breakers. Its functions are to insulate, suppress corona and arcing, and serve as a coolant.

When transformer oil reaches the end of its life, it is usually unfit for further use because of its accumulated contaminants and the loss of electrical, chemical and physical performance. However, using advanced technology, it is possible to treat this oil and recycle it. Recycling transformer oil avoids emissions because the waste oil is typically incinerated to destroy its toxic contaminants, which causes CO_2 emissions. In addition, recycling can displace the emissions associated with the extraction of crude oil, refining and transport for use in transformers. Oil used in the electricity distribution sector also contains Polychlorinated Biphenyls (PCBs), and this project requires the proper treating and disposal of PCBs which are a known carcinogen. One main environmental benefit of the project is therefore the elimination of health and safety risks associated with the destruction of PCBs.

1.2 Applicability Criteria

Project Proponents can achieve emissions reductions by recycling transformer oil used in transformers that are used and operated by electric utility customers and large industrial companies[1] that would otherwise be combusted, thus generating CO_2 emissions. This methodology is applicable under the following conditions:

- The project must treat used transformer oil, and remove toxic contaminants like PCBs, for re-use of the oil in transformers.
- It can be demonstrated that in the absence of the project, the transformer oil would have been incinerated.
- The transformer oils re-refined by the project activity in a waste-oil refinery (hereafter referred to as “Project Site”) are of the same quality as the original raw products, as evidenced by the fact that they can be used for the same purpose as the original oil.

[1] This methodology can be applied to any company with large electrical load that would have transformers on site.

- This methodology cannot be applied in cases when transformer oil is taken out of the transformer and put into another unit, or other equipment, on a short-term basis after filtration or similar clean up. In some cases in the utility industry, this action occurs, and the oil can only be used for a short period of time and then discarded. This situation is more akin to a maintenance activity that extends the oil's life before it goes to incineration or, in the case of this method, re-refining. Such an activity would not qualify for carbon credits. This methodology can only be applied when the oil is "re-refined" which in this context is defined as converting used oil into a recycled product that complies with the technical performance standards for electrical insulating oil described by published ASTM technical standards, or equivalent.
- The project complies with all local or national regulations related to proper disposal of toxic substances such as PCBs.
- Use of this methodology is limited to projects in the United States due to the method for calculating project emissions from electricity use. Future versions of the methodology may expand applicability.

1.3 Periodic Reviews and Revisions

The American Carbon Registry® (ACR) may require revisions to this methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project activities. This methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the Project Proponent should ensure that they are using the latest version of the methodology.

Once a GHG Project Plan is certified and validated, it remains valid for the duration of the project Crediting Period regardless of methodology updates. An Annual Attestation by the Project Proponent is required. Validation is required once per Crediting Period, and verification is required prior to any new issuance of ERTs, as described in the *ACR Standard*. ACR will review Annual Attestations and periodic verification statements and notify the Project Proponent of any required adjustments or corrections to these documents. Once a GHG Project Plan has been certified by ACR, the project may be listed. Once ACR has accepted a verification statement, ACR will register verified emission reductions as ERTs.

1.4 Acronyms and Definitions

ASTM technical standards	ASTM International, formerly known as the American Society for Testing and Materials (ASTM), is a leader in the development and delivery of international voluntary consensus standards
EF	Emissions factor, used in this methodology to determine the carbon content of petroleum products
EGC	Electricity Generating Company (used in the USEPA's eGRID database)
MWh	Megawatt-hour
NCV	Net Calorific Value, used to determine the energy content of petroleum products
NERC	North American Electric Reliability Corporation
PCA	Power Control Area, a level of aggregation in eGRID
PCBs	Polychlorinated Biphenyls used as dielectric and coolant fluids, for example in transformers, capacitors, and electric motors but banned in the United States due to their toxicity.
Project Proponent	The company or entity that is organizing and managing the project and is the owner of the emission reduction credits.
Project Site/Refining Facilities	Industrial facility where transformer oil, once it has been used, can be treated and re-refined to meet the standards of virgin oil.
Recycled transformer oil	Transformer oil taken out of a transformer and put into another unit, or other equipment, on a short-term basis after filtration or similar clean up. This oil typically does not meet the technical performance standards for electrical insulating oil described by published ASTM technical standards, or equivalent.
Re-refined transformer oil	Transformer oil that is completely treated to the point that is has all of the characteristics, functionality and life span as virgin oil. Re-refined oil meets the technical performance standards for electrical insulating oil described by published ASTM technical standards, or equivalent.
SSRs	Greenhouse gas sources, sinks and reservoirs
Transformer oil	A highly refined oil with excellent electrical insulating properties that is used in oil-filled transformers to insulate, suppress corona and arcing,

	and serve as a coolant.
TO	Transformer oil
USEPA	U.S. Environmental Protection Agency

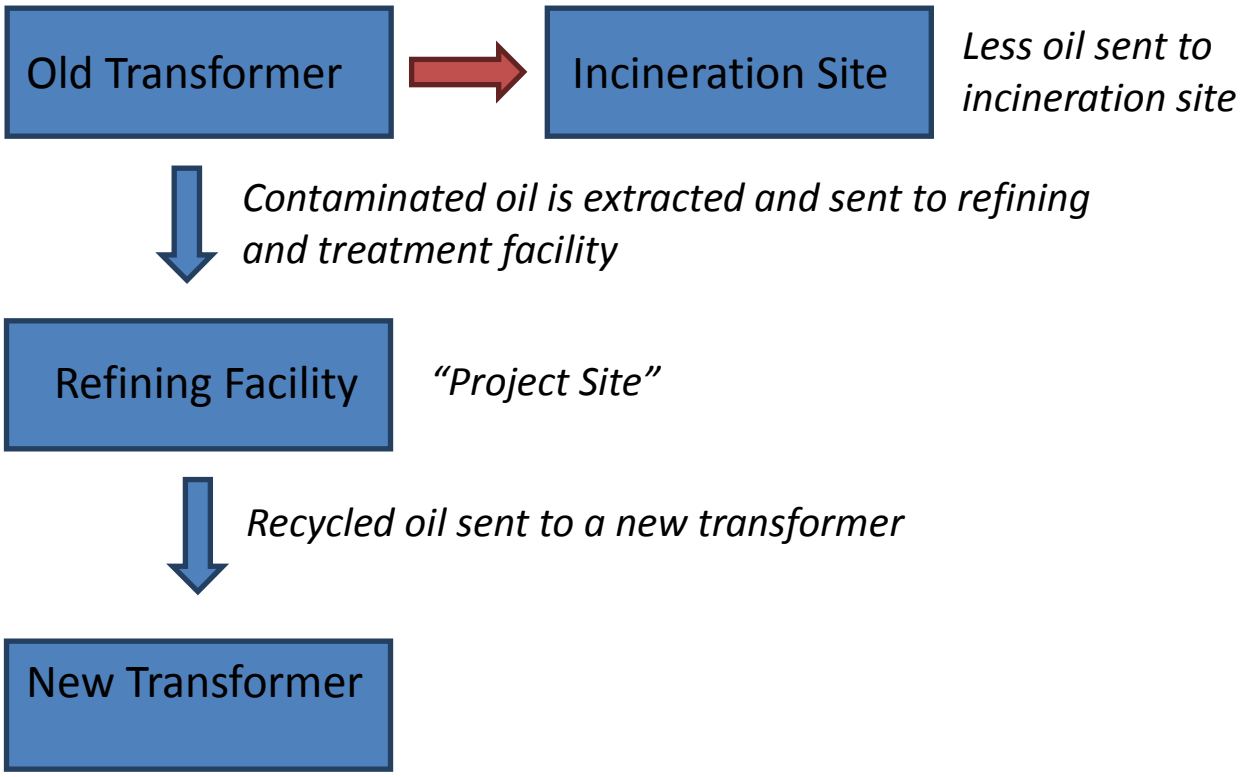
2: PROJECT BOUNDARIES

ACR defines the GHG offset project boundary to include a project's geographical implementation area, temporal boundary, and the GHG assessment boundary (i.e. GHG sources, sinks and reservoirs (SSRs) included).

2.1 Physical Boundary

The physical boundary is defined as the location where the waste oil is collected, the refining and treatment facility, as well as the location where the re-refined oil is used. Also considered as part of the project but not explicitly in the project boundary is the infrastructure needed to extract and refine the oil that is used in the baseline situation. See Figure 1 for an illustration of the physical boundary.

Figure 1: Project Boundaries



2.2 Project start date and crediting period

Per the *ACR Standard,* the project Start Date is the date on which the project began to reduce GHG emissions against its baseline. For projects under this project, the Start Date corresponds to the refining facility's first operating hour. The earliest eligible Start Date for this project type is January 1, 2000. Thus, historic start date projects are eligible to earn ERTs as long as they comply with ACR guidelines on additionality and Start Date and meet all other ACR requirements.

Per the *ACR Standard,* the project Crediting Period is the length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. Projects using this methodology will have a Crediting Period of seven (7) years, with the first Crediting Period beginning on the Start Date. Crediting Periods may be renewed by re-submitting the GHG Project Plan in compliance with current ACR baseline, additionality and monitoring standards at the time of renewal.

2.3 GHG Assessment Boundary

The GHG assessment boundary encompasses all primary effects and significant secondary effects associated with the project. The GHG assessment boundary is used to identify the GHG emission sources that must be examined to quantify a project's GHG reductions, as well as sources that may be excluded either because they are insignificant or because exclusion is conservative (i.e. will lead to an underestimate of net GHG reductions).

Table 1. Emission Sources included in the GHG Assessment Boundary

	Gas	Included/Excluded	Description
Baseline	CO_2	Included	Main gas emitted from the combustion of used transformer oil in the baseline
	CH_4	Excluded	Emissions of CH_4 during combustion of baseline fuel are expected to be negligible.
	N_2O	Excluded	Emissions of N_2O during combustion of baseline fuel are expected to be negligible.
Project	Energy use at re-refining facility		
	CO_2	Included	Main gas emitted from the operation of the re-refining facility (electricity and fuel usage, combustion of

			syngas).
	CH_4	Excluded	Emissions of CH_4 from energy use at re-refining facility are expected to be negligible.
	N_2O	Excluded	Emissions of N_2O from energy use at re-refining facility are expected to be negligible.
	Transportation of used oil to re-refining facility		
	CO_2	Excluded	Transportation of used transformer oil to the re-refining facility will cause CO_2 emissions. However, in both the project and baseline cases, waste oil has to be transported to either a re-refining plant or an incineration plant. There is no reason to assume that refining facilities would be located any farther from the oil's point of origin than an incineration plant.[2] Thus this source is treated as negligible.
	CH_4	Excluded	Emissions of CH_4 from transportation are expected to be negligible.
	N_2O	Excluded	Emissions of N_2O from transportation are expected to be negligible.

[2] A dedicated oil refining facility may actually be more advantageously sited near power generation facilities, as opposed to an incineration facility. In any case, the difference – if there is one – would be negligible relative to the size of the emissions associated with combusting the waste oil.

3: BASELINE DETERMINATION AND ADDITIONALITY

3.1 Baseline Determination

The baseline scenario is the continued incineration of used transformer oil. Project Proponents must demonstrate that the re-refining of used transformer oil to meet specifications for re-use in transformers is not common practice per the Additionality assessment in Section 3.2. In some cases, small amounts of transformer oil are recycled to a lesser, technical short-term use, although the vast majority of used transformer oil is destroyed in incineration or combustion processes, thus emitting CO_2 to the atmosphere. As such, the basic assumption in this methodology is that in the baseline, all waste transformer oils are incinerated.

As described in Section 3.2, Project Proponents should demonstrate that the type of oil they refine and recycle cannot be refined and recycled using common technology (e.g. the oil is too contaminated and requires advanced treatment and cleaning that is uncommon in the market). In these cases, it can be assumed that 100% of the oil would have otherwise been incinerated.

3.2 Additionality

Emission reductions from the project must be additional, or deemed not to occur in the business-as-usual scenario. Assessment of the additionality of a project will be made based on passing the three tests cited below. Project Proponents utilizing this methodology should consult the latest version of the *ACR Standard*, which may be updated from time to time. At the time of the drafting of this methodology, the three additionality tests include:

1. Regulatory Surplus Test
2. Common Practice Test, and
3. Implementation Barriers Test

Further guidance on these tests is given below.

TEST 1: Regulatory Surplus: In order to pass the regulatory surplus test, a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect now, or as of the project Start Date, that directly or indirectly affect the credited GHG emissions associated with a project. The Project Proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires either recycling or re-refining of transformer oil (including for reasons other than avoiding GHG emissions).

TEST 2: Common Practice Analysis: The common practice test is designed to demonstrate that the project activity is not already being undertaken as a matter of common practice. It is to answer the question of whether, in the industry supplying the used transformer oil that is re-refined in the project activity, waste transformer oil is routinely recycled instead of combusted. The GHG Project Plan should demonstrate that recycling of used transformer oil is not common practice in the industry. For example, this assessment could sample market data about how different users of transformer oil dispose of their waste oil. While some oil in the market may be recycled, the use of a new or more expensive technology to recycle particularly contaminated oil – such as oil with high levels of silicon – could mean that oil would otherwise be incinerated.

Project Proponents can demonstrate that the *use of the technology* is not common practice by providing clear evidence that its technology is more expensive than its competitors and thus has little presence in the market. In addition, the oil may be recycled at a higher cost, which might mean in the absence of the project, that oil would be incinerated.

TEST 3: Implementation Barrier Analysis: The Project Proponent should establish that the project overcomes at least one prohibitive financial, technological, or institutional barrier. In order to demonstrate that there are prohibitive barriers to the project being implemented, the Project Proponent will provide documented evidence, and offer conservative interpretations of this evidence, as to how the project is overcoming the identified barrier. Anecdotal evidence can be included, but alone is not sufficient proof of barriers. Demonstration of the project facing at least one of the three barriers below is required for approval of the project.

- *Financial Barriers:* The financial barriers test is intended to answer the following questions: Does the project face capital constraints that carbon revenues can potentially address; or is carbon funding reasonably expected to incentivize the project's implementation; or are carbon revenues a key element to maintaining the project action's ongoing economic viability after its implementation? To pass the financial barriers test, the project should face capital constraints that carbon revenue will play a significant role in helping it overcome. Financial constraints can include, but are not limited to:

    a. High costs – material and personnel costs associated with construction of the project.

    b. Immaterial or low returns – project's internal rate of return (IRR) does not meet documented company thresholds.

    c. Limited access to capital or capital constraints due to the nature of the project.

    d. High risks from new or unproven business models.

If the financial barriers test is selected for the project, the Project Proponent should both explain the financial barriers and provide sufficient supporting documentation at the time of the project validation. In this case, an example of possible financial analysis argument could be that the Project Proponent is forced to buy the old transformer at a higher price to secure the used oil than another company that would simply burn it. In this case, the revenues from the sale of carbon credits could help improve project finances enough to outbid competitors without eliminating the project's profitability. If any financial barriers test is used, the Project Proponent should provide a full financial analysis.

- *Technological Barriers:* The technological barriers test is intended to answer the following questions: Is a primary reason for implementation of the technology in question its GHG reduction capabilities or benefits, and is the reduction of GHG emissions one of the goals of the project at the Start Date? Technological barriers can include high R&D costs, deployment risk of new technologies, and lack of trained personnel available on-site to install, maintain, or properly operate the equipment or any other relevant technological barriers. If the technological barriers test is selected for the project, the Project Proponent should both explain the technological barriers and provide, at the time of the project validation, sufficient supporting documentation.

- *Institutional Barriers:* The institutional barriers test is intended to answer the following question: Does the project face significant organizational, cultural, or social barriers to achieving GHG emission reductions that the accrual of benefits from the project action will help to overcome? Institutional barriers can include a scarcity of human resources for technology implementation, lack of support from management or operations personnel for new technology practices, an aversion to investment in an area where risks and returns are unfamiliar (as opposed to actual capital constraints), lack of awareness or concern with the benefits of the project, or any other relevant institutional barriers. If the institutional barriers test is selected for the project, the Project Proponent should both explain the institutional barriers and provide, at the time of the project validation, sufficient supporting documentation.

4. QUANTIFICATION OF BASELINE AND PROJECT EMISSIONS

4.1 Baseline Emissions

Baseline emissions (BE_y) will be determined in the following manner.

$$BE_y = BE_{TOI,y} \quad \textbf{(1)}$$

Where

BE_y	Baseline emissions in year *y* (tCO_2).
$BE_{TOI,y}$	Baseline emissions from transformer oil incineration (TOI) avoided through re-refining (tCO_2).

$$BE_{TOI,y} = \sum FC_{TO,y} * EF_{TO,y} \quad \textbf{(2)}$$

Where

$FC_{TO,y}$	Energy content of baseline fuel, the transformer oil (TO) that would otherwise be combusted in year y (terajoule or TJ).
$EF_{TO,y}$	Emission factor of *TO* in year y (tCO_2/TJ) (see below).

Where fuel data are collected in US gallons, the energy content of fuel of a particular kind combusted in year *y* ($FC_{TO,y}$) can be estimated as

$$FC_{TO,y} = \frac{Gallons_{Fuel,TO,y} \times Density_{Fuel,TO,y} \times NCV_{Fuel}}{10^6} \quad \textbf{(3)}$$

Where

$FC_{TO,y}$	Energy content of TO in year y; TJ
$Gallons_{Fuel,TO,y}$	Quantity of TO collected for recycling year *y*; gal

$Density_{Fuel,TO,y}$ Density of TO; kg.gal^{-1}.

NCV_{Fuel} Net Calorific Value of TO (Gg^{-1})

For each of these factors – the emissions factor ($EF_{TO,y}$), the density, and the NCV – Project Proponents may elect to use the defaults in Tables 3 to 5 in Section 4.2 for Gas/Diesel Oil because transformer oil most closely matches this type of hydrocarbon. If the transformer oil is different from the energy and carbon content of diesel fuel, then Project Proponents should outline the procedures for measuring these factors or justify an alternative default.

NCV and EF defaults: The rationale for using diesel fuel as defaults for the NCV and EF can be justified as follows. Transformer oil is a highly specified product and its properties are therefore very consistent. During its use, the oil's primary characteristics do not change significantly, and the waste oil comes to the project facility essentially unchanged (at least in energy terms). The energy content and emission factors for a fuel are substantially determined by its carbon chain length. Transformer oil typically has a longer chain than diesel, making it slightly denser and giving it a higher carbon/energy content per unit of volume or mass. For this reason using diesel is a conservative way to approximate the energy content and emission factors for transformer oil. If one were to do an direct measurement, the result would reveal a higher carbon content than the known diesel numbers. As a result, using the NCV and EF defaults for Gas/Diesel Oil is likely to underestimate $BE_{TOl,y}$, thus understating net emission reductions credited to the project activity.

According to one source, the New Zealand Ministry of Environment, the following table illustrates the length of hydrocarbons, including transformer oil.

Table 2: Carbon chain lengths for typical hydrocarbons

Source: New Zealand Ministry of Environment

Product	Minimum Carbon number	Maximum Carbon number
Natural gas	1	1
CNG	1	2
LPG	2	3
Ligroine	4	7
Mineral spirits	7	11
Toluol	6	6
Petrol	4	12
Diesel	8	17

Xylol	7	7
Kerosene	8	17
Aviation turbine fuel	8	16
Gas oil, fuel oil	11	High
Transformer oil	15	High

Annex B also provides the standard for transformer oil from ASTM International, formerly known as the American Society for Testing and Materials. ASTM is a globally recognized leader in the development and delivery of international voluntary consensus standards.

4.2 Project Emissions

Project Emissions (PE) are determined primarily from the electricity and fuel requirements from the Project Site itself, the location which refines the old transformer oil. PE can be calculated as follows:

$$PEy = PE_{elec} + PE_{ffc} \quad \textbf{(4)}$$

Where

PEy — Project emissions for year y of the crediting period (tCO_2).

PE_{elec} — Project emissions from the use of electricity at the refining facility (tCO_2).

PE_{ffc} — Project emissions from the combustion of fossil fuels used for the refining facility, such as use in boilers or on-site electricity generation (tCO_2).

Project emissions from the use of electricity at the refining facility are calculated as follows:

$$PE_{elec} = (Q_{electricity,y} * Rate_{eGRID} / 2{,}205) \quad \textbf{(5)}$$

Where

$Q_{electricity,y}$ — Quantity of electricity used by the Project Site in year y (MWh)

Rate*eGRID*	Emission rate for CO_2, by (in order of preference) Power Control Area, eGRID subregion, or State (lb/MWh). The latest available version of eGRID at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html shall be used. See more detail below.
2,205	Conversion from lb/MWh to metric tons/MWh

CO_2 emissions from power generation are estimated using data from the USEPA's Emissions & Generation Resource Integrated Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of electric power generated in the United States, including emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide, net generation, resource mix, and other attributes.[3] As of publication of this methodology, the latest release is eGRID2012 version 1.0, containing data through 2009. The latest published version of eGRID shall always be used.

eGRID2012 provides data organized by power control area (PCA), North American Electric Reliability Corporation (NERC) region, eGRID subregion, U.S. state, and other levels of aggregation. The PCA, eGRID subregion, and NERC region data are based on electricity generation, transmission and distribution areas so effectively represent the emissions associated with the mix of GHG-emitting and non-emitting resources used to serve load in those areas.

The Project Proponent must use emission factors from the latest version of eGRID. The Proponent should download, from the eGRID website, the data files spreadsheet; for eGRID2012 Version 1.0, this is called "eGRID2012 year 2009 data files.xls". Note the "Contents" tab shows the various levels of aggregation included in the other spreadsheet tabs.

To calculate CO_2 emissions from the electric power consumed by refining facility included within the project boundary, the Project Proponent will multiply total kWh consumed for that project site and reporting period by one of the following eGRID emission factors, drawn from the data spreadsheet. *The data aggregation levels are to be used in the order of preference below; i.e. if the PCA can be identified the emission factor from this tab must be used. Only if it is not possible to use the preferred level of aggregation is it permitted to move to the next level.*

1. In eGRID2012 version 10, the **PCAL09** tab has data for 119 Power Control Areas across the United States. This methodology considers those PCA emission factors to be the most precise representation of emissions caused by TO re-refining facilities and thus requires the PCA emission rate to be used as long as the PCA can be identified. In the

[3] See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

PCAL09 tab, look up the appropriate PCA in the left-hand column and scroll across to the column giving the **PCA annual CO_2 total output emission rate** in lb/MWh.

2. *Only if the PCA is not known*, use the eGRID subregion data in the **SRL09** tab. This includes emission factors for 26 eGRID subregions covering the United States (see "eGRID2012_eGRID subregion representational map," reproduced in Annex A). Look up the appropriate eGRID subregion in the left-hand column and scroll across to the column giving the **eGRID subregion annual CO_2 total output emission rate** in lb/MWh.
3. *Only if the PCA is not known and it is not feasible to place the TSE facility definitively in an eGRID subregion* (e.g. because it is located near a boundary between two subregions), use the data aggregated by U.S. state in the **ST09** tab. This will be the least precise because electricity generation, transmission and distribution regions do not follow state boundaries. Look up the state where the TSE facility is located in the left-hand column and scroll across to the column giving the **State annual CO_2 total output emission rate** in lb/MWh.

Project emissions from the combustion of fossil fuels used for the refining facility are calculated as follows:

$$\mathbf{PE_{ffc}} = \sum_{a} FC_{a,y} * EF_{a,y} \qquad \textbf{(6)}$$

Where

$FC_{a,y}$	Energy content of fuel type a combusted the year y (terajoule or TJ).
$EF_{a,y}$	Emission factor of fuel type *a* in year y (tCO_2/TJ). Project Proponents can use a default for $EF_{a,y}$ as outlined in Table 3 below and on p. 47 of the ACR Tool for Estimation of Stocks in Carbon Pools and Emissions from Emission Sources.
a	Fuel types combusted during year y

Where fuel data are collected in US gallons, the amount of fuel of a particular kind combusted in year *y* ($FC_{a,y}$) can be estimated as

$$FC_{a,y} = \frac{Gallons_{Fuel,a,y} \times Density_{Fuel,a,y} \times NCV_{Fuel}}{10^6} \quad (7)$$

Where

$Fuel_{a,y}$	Energy content of fuel type *a* consumed in year y; TJ
$Gallons_{Fuel,a,y}$	Quantity of fuel of type *a* consumed in year *y*; gal
$Density_{Fuel,a,y}$	Density of fuel type *a*; kg.gal-1. See Table 4.
NCV_{Fuel}	Net Calorific Value of Fuel type *a*; TJ.Gg-1. See Table 5 below.

Table 3: Emission Factors for Fuels

Fuel Type	Default effective CO_2 emission factor ($tCO_2.TJ^{-1}$)
Motor gasoline	69.3
Gas/Diesel Oil	74.1
Liquefied Petroleum Gases	63.1
Kerosene	71.9
Lubricants	73.3
Compressed Natural Gas	56.1
Liquefied Natural Gas	56.1

The emission factors assume that 100% of the carbon content of the fuel is oxidized during or immediately following the combustion process (for all fuel types in all vehicles) irrespective of whether the CO_2 has been emitted as CO_2, CH_4, CO or NMVOC or as particulate matter.

Table 4. Typical Density Values for Selected Petroleum Products.

Fuel Type	Density ($kg.ltr^{-1}$)	Liters per ton	Density ($kg.gal^{-1}$)	Gallons per ton
Motor gasoline	0.7407	1350	2.800	357
Gas/Diesel Oil	0.8439	1185	3.190	313
Naphtha	0.6906	1448	2.610	383
Aviation gasoline	0.7168	1350	2.710	357
Aviation Turbine fuel	0.8026	1246	3.034	330
Other kerosene	0.8026	1246	3.034	330

Table 5. Default Net Calorific Values (NCV) for Selected Petroleum Products.

Fuel Type	Density (kg / ltr)	NCV (GJ/t)[a]
Motor gasoline	0.7407	44.75
Gas/Diesel Oil	0.8439	43.38
Naphtha	0.6906	45.34
Aviation gasoline	0.7168	45.03
Aviation Turbine fuel	0.8026	43.92
Other kerosene	0.8026	43.92

[a] 1000 GJ = 1 TJ

Table: Default NCVs (excerpt from table 1.2, Chapter 1, Volume 2, IPCC, 2006 Inventory Guidelines)

Fuel type (English description)	Default Net Caloric Value (NCV) (TJ/Gg)[b]
Crude Oil	42.3
Orimulsion	27.5
Natural Gas Liquids	44.2
Motor Gasoline	44.3
Aviation Gasoline	44.3
Jet Gasoline	44.3
Jet Kerosene	44.1
Other Kerosene	43.8
Gas/Diesel Oil	43.0
bio-gasoline/bio-diesel	27.0
other liquid biofuels	27.4

[b] TJ/Gg = GJ/t

4.3 Leakage

Leakage (L_y) is defined as an increase in emissions outside the project boundary attributable to the implementation of the project. In cases where leakage occurs, it must be accounted for and subtracted from the reported net GHG emission reductions for the reporting period. In this case, all potential sources of emissions are accounted for in the project boundary and it is unlikely that

any emissions would occur outside the project boundary. Thus leakage does not need to be considered in this case.

4.4 Emission Reductions

Emission reductions can be calculated by subtracting Project Emissions $\boldsymbol{PE_y}$ (emissions happening as a result of the project) from Baseline Emissions, $\boldsymbol{BE_y}$ (the emissions that would have occurred in the absence of the project).

$$\boldsymbol{ER_y = BE_y - PE_y} \qquad \textbf{(8)}$$

Where

ER_y	Emission reductions in year y; tCO_2
BE_y	Baseline emissions in year y, calculated in Equation (1); tCO_2
PE_y	Project emissions in year y, calculated in Equation (4); tCO_2

5: DATA COLLECTION AND MONITORING

5.1 Monitoring Plan Guidelines

A monitoring plan is a working document that describes procedures for collecting activity data, baseline and project emissions data, and for ensuring and controlling the quality of the collected data. The project monitoring plan will be updated whenever the methodologies used to measure project activity or baseline emissions are changed. Some of the key GHG accounting principles that should drive the design of data collection and monitoring include:[4]

- *Relevance*: levels of accuracy and uncertainty associated with monitoring approaches should reflect the intended use of the data and the objectives of the offset project. Some intended uses may require greater accuracy than others.
- *Accuracy*: measurements, estimates, and calculations should be unbiased, and uncertainties reduced as far as practical. Calculations and measurements should be conducted in a manner that minimizes uncertainty.
- *Conservativeness*: where there are uncertainties in monitored data, values used to quantify GHG reductions should err on the side of underestimating rather than overestimating reductions.

It is critical for the accuracy and transparency of calculating, monitoring and verifying GHG reductions that:

- Amount of oil collected and treated is weighed with industry-standard accuracy using methods and scales that are annually calibrated within the manufacturer's specifications.
- All information required to capture project emissions is calculated using data obtained as accurately as possible, including: electricity consumed at the Project Site and fuel combusted at the project site, if any. Project Proponents should develop a monitoring system and database to transfer records, such as utility bills (providing detailed accounting of power and gas used) as well as diesel or other fuel shipments. This database and individual records, such as utility bills, may be spot-checked during verification.

[4] Based on World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), *GHG Protocol for Project Accounting*, November 2005.

Table 6: Parameters Monitored

Parameter	Description	Data Unit	Calculated [c], Measured [m], Reference [r], Operating records [o]	Measurement frequency	Comment
$Q_{electricity,y}$	Electricity requirements for the facility	MWh	M	Continuous	On-site records from utility bills
$Gallons_{Fuel,a,y}$	Quantity of fuel of type *a* consumed in year *y* associated with the refining facility	Gallons	M	Continuous	On-site records from fuel purchases
Rate*eGRID*	Emission rate for CO_2, by (in order of preference) Power Control Area, eGRID subregion, NERC region, or State	Lb CO_2/MWh	R	Annual	Use most recently available eGrid Database[5]
$Gallons_{Fuel,TO,y}$ and $Gallons_{Fuel,a,y}$	Quantity of transformer oil that is captured and recycled in year *y* (baseline) and quantity of fossil fuel used in Project Site (project)	Gallons	M	Continuous	On-site records
$Density_{Fuel,TO,y}$ and $Density_{Fuel,a,y}$	Density of transformer oil (TO) (baseline) and of fossil fuel used in Project Site (project)	kg.gal-1.	R	Once	See Table 4
$EF_{TO,y}$ and $EF_{a,y}$	Emission factor of *TO* baseline) and of fossil fuel used in Project	tCO_2/TJ	R	Once	See Table 3

[5] See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

	Site (project) in year y				
NCV_{Fuel}	Net Calorific Value of TO baseline) and of fossil fuel used in Project Site (project)	(GJ/t)	R	Once	See Table 5
EF_{COP}	Default emissions factor for methane emissions associated with crude oil production	tCH4/PJ	R	Once	See Table 2

5.2 Validation and Verification Interval

Per the *ACR Standard*, validation of the GHG Project Plan will occur once per Crediting Period. Verification of GHG assertions is at the discretion of the Project Proponent, provided it conforms to ACR requirements. Verification must occur prior to any new issuance of ERTs. ERTs may be created and issued annually, or at the Proponent's request, more or less frequently. At each request for issuance of new ERTs, the Project Proponent must submit a verification statement from an approved verifier based on a desk audit. No less than once every five years, Proponents must submit a verification statement based on a full verification including a field visit to the Project Site, the location where the transformer oil is being re-refined.

6: EMISSIONS OWNERSHIP

6.1 Statement of Direct Emissions

The Project Proponent shall attest that all emission reductions are the result of activities solely attributable to actions of the Project Proponent, and that none of the emissions claimed by the project are indirect emissions. The Project Proponent, when obtaining the waste oil from the utility or industrial client, will review the websites and other public material of the companies that supply the waste oil, to make sure these companies make no claims about the GHG benefits. If these users of transformer oil are claiming the GHG benefits of the avoidance of combustion, the Project Proponent will request the company to revoke those claims. If unsuccessful in this effort, no ERTs would be issued for the quantity of oil from that utility or industrial supplier. Alternatively the Project Proponent could have an agreement with the supplier waiving any right to the carbon benefits.

6.2 Permanence

Project Proponents should demonstrate that the emissions reduced by the project are permanently reduced. In this case, it can be reasonably expected that the emission reductions are permanent because in the absence of the project, the transformer oil would have been incinerated. Even if the recycled oil is used only once and then incinerated, is has still displaced once oil that would have otherwise been incinerated. Once that emission is avoided, it cannot subsequently be reversed or re-emitted. No buffer contribution or other risk mitigation mechanism is therefore required under this methodology.

6.3 Title

Project Proponents shall provide evidence that they have title or contractual rights to the emission reductions claimed in the GHG Project Plan and monitoring reports and that no other entity has a conflicting claim over the emission reduction claimed in the in the GHG Project Plan and monitoring reports. Project Proponents seeking ERTs must deal with potential scenarios in which other parties involved in these projects can possibly claim ownership of the credits. These parties must have contractual arrangements necessary to ensure that ownership of emission reductions is clear, uncontested and rests with only one party. In this scenario the Project Proponent would need to ensure that the user of the recycled oil is not also claiming carbon credits.

6.4 Community and Environmental Impacts

The Project Proponent shall take into account ACR's Community and Environmental Impacts criteria when applying this methodology to specific projects. These criteria require analysis of any adverse environmental or social impacts on the communities near the project boundary. If there are any adverse environmental problems that may result from the project itself, Project Proponents should conduct stakeholder meetings with community groups or other appropriate NGOs to ensure that any concerns associated with the project are addressed. All applicable environmental permitting and review regulations shall be complied with and all relevant stakeholders shall be consulted.

Per the *ACR Standard*, community and environmental impacts must be net positive overall. Project Proponents shall document in the GHG Project Plan a mitigation plan for any foreseen negative community or environmental impacts, and shall disclose in their Annual Attestations any negative environmental or community impacts or claims by community members of negative environmental and community impacts.

6.5 Warranties

The Project Proponent shall include in the GHG Project Plan the following warranty: "I hereby warrant that all information provided by [Project Proponent] in this GHG Project Plan is true and factual, and all matters affecting the validity of this GHG Project Plan or consequent emission reduction credit claims have been fully disclosed. This project has not been previously registered with any other emission reduction program or regulatory agency. [Project Proponent] has title to the GHG emission reductions created by this project, and warrants that no security has been granted over those rights, and said rights are valid. Any ERT delivery risks associated with lack of statutory rights, governmental agency recognition, or future emission reduction creation operations commensurate with potential ERT forward option volumes will be mitigated by [Project Proponent] via clearinghouse, registry, and/or insurance instruments, as appropriate."

6.6 Annual Attestations

The Project Proponent shall submit Annual Attestations, as required in the *ACR Standard*, in a format to be provided by ACR. The Annual Attestations address continued undisputed ownership of emission reductions, any claims of negative environmental or community impacts, and a mitigation plan in the case of such claims.

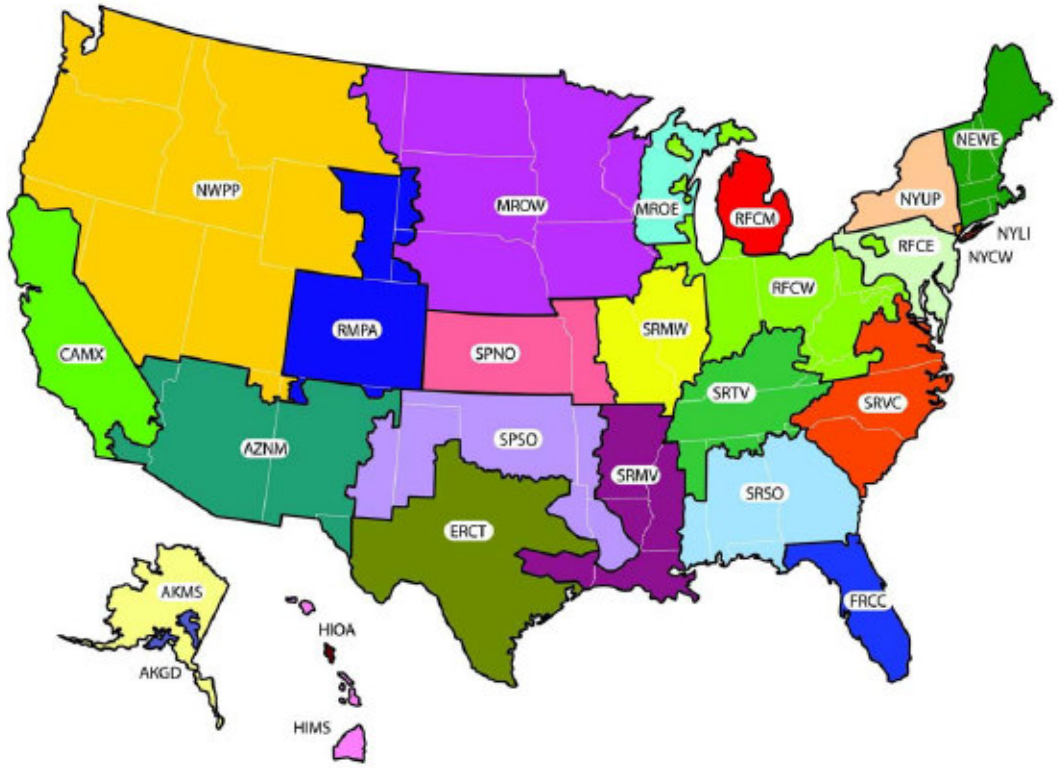
7: QA/QC PROCEDURES AND RISK MITIGATION

The Project Proponent shall maintain a Quality Assurance/Quality Control (QA/QC) program including measures such as:

- Accurate measurements of weighing of waste transformer oil. The Project Proponent should retain all weigh scale receipts generated either on- or off-site indicating the weight and source of all waste oil delivered to the project facility. In the case of any missing or poor-quality data, adjustments or assumptions made as part of the QA/QC process should be made in a conservative direction, i.e. where data or assumptions used to compensate for missing data should tend to underestimate net emission reductions.
- Calibrations on key monitoring instrumentation are made at least annually or per the manufacturer specifications, whichever is more frequent. More frequent calibrations may be necessary if any QA/QC issues are indicated.
- Responsible entities: field personnel and corporate data system manager shall be responsible for data capture, to ensure data are properly recorded into the database.
- A designated corporate QA/QC officer shall be responsible for the following:
    a. Development, implementation, and oversight of QA/QC procedures for measurement, calibration, and data collection of CO_2-related data;
    b. Assess calculation results to ensure data have been properly processed;
    c. Strategies for identifying and managing missing or poor-quality data, and making any necessary adjustments to data based on findings from the QA/QC measures;
    d. Daily log sheets, calibration and maintenance records, utility bills/receipts, and other electronic and hard-copy data records shall be archived for a minimum of three (3) years to support future auditing and verification activities.
- Emission reduction estimates shall be made so as to overstate project emissions and understate baseline emissions, thereby erring on the side of understating net GHG emission reductions.

ANNEX A: EMISSION RATES FOR EGRID SUBREGIONS

The following map and table show the eGRID subregions and GHG emission rates, used in section 4.3 to calculate CO_2 emissions from TSE use. Note these eGRID subregion rates may only be used in the case that the Power Control Area is not known. See http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.



eGRID subregion acronym	eGRID subregion name	Annual total output emission rates			Annual non-baseload output emission rates		
		Carbon dioxide (CO_2) (lb/MWh)	Methane (CH_4) (lb/GWh)	Nitrous oxide (N_2O) (lb/GWh)	Carbon dioxide (CO_2) (lb/MWh)	Methane (CH_4) (lb/GWh)	Nitrous oxide (N_2O) (lb/GWh)
AKGD	ASCC Alaska Grid	1,280.86	27.74	7.69	1,320.75	33.16	6.34
AKMS	ASCC Miscellaneous	521.26	21.78	4.28	1,469.44	61.53	12.10
AZNM	WECC Southwest	1,191.35	19.13	15.58	1,187.67	22.25	9.12
CAMX	WECC California	658.68	28.94	6.17	993.89	33.52	4.07
ERCT	ERCOT All	1,181.73	16.70	13.10	1,155.44	19.66	7.59
FRCC	FRCC All	1,176.61	39.24	13.53	1,301.40	36.04	11.91
HIMS	HICC Miscellaneous	1,351.66	72.40	13.80	1,615.98	91.06	17.19
HIOA	HICC Oahu	1,593.35	101.74	21.98	1,621.42	107.94	18.73
MROE	MRO East	1,591.65	23.98	27.04	1,868.23	29.40	30.40
MROW	MRO West	1,628.60	28.80	27.79	2,114.93	61.83	37.41
NEWE	NPCC New England	728.41	75.68	13.86	1,157.44	61.72	14.43
NWPP	WECC Northwest	819.21	15.29	12.50	1,404.55	38.56	18.79
NYCW	NPCC NYC/Westchester	610.67	23.75	2.81	1,118.06	22.47	2.31
NYLI	NPCC Long Island	1,347.99	96.86	12.37	1,336.59	30.78	3.51
NYUP	NPCC Upstate NY	497.92	15.94	6.77	1,347.12	41.08	16.87
RFCE	RFC East	947.42	26.84	14.96	1,628.97	32.94	22.46
RFCM	RFC Michigan	1,659.46	31.41	27.89	1,834.66	35.17	29.15
RFCW	RFC West	1,520.59	18.12	25.13	2,001.76	24.56	32.10
RMPA	WECC Rockies	1,824.51	22.25	27.19	1,756.62	23.54	22.51
SPNO	SPP North	1,815.76	21.01	28.89	2,147.53	26.32	31.82
SPSO	SPP South	1,599.02	23.25	21.79	1,513.73	25.22	15.11
SRMV	SERC Mississippi Valley	1,002.41	19.45	10.65	1,201.66	25.72	7.11
SRMW	SERC Midwest	1,749.75	19.57	28.96	2,192.85	25.04	35.89
SRSO	SERC South	1,325.68	22.27	20.78	1,622.00	27.22	23.50
SRTV	SERC Tennessee Valley	1,357.71	17.28	22.09	1,921.12	25.16	30.61
SRVC	SERC Virginia/Carolina	1,035.87	21.51	17.45	1,677.35	38.55	25.56
U.S.		**1,216.18**	**24.03**	**18.08**	**1,555.48**	**30.83**	**19.76**

ANNEX B: ASTM INTERNATIONAL STANDARD SPECIFICATION FOR MINERAL INSULATING OIL USED IN ELECTRICAL APPARATUS

Designation: D3487 – 09

Standard Specification for Mineral Insulating Oil Used in Electrical Apparatus[1]

This standard is issued under the fixed designation D3487; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

This standard has been approved for use by agencies of the Department of Defense.

1. Scope

1.1 This specification covers new mineral insulating oil of petroleum origin for use as an insulating and cooling medium in new and existing power and distribution electrical apparatus, such as transformers, regulators, reactors, circuit breakers, switchgear, and attendant equipment.

1.2 This specification is intended to define a mineral insulating oil that is functionally interchangeable and miscible with existing oils, is compatible with existing apparatus and with appropriate field maintenance,[2] and will satisfactorily maintain its functional characteristics in its application in electrical equipment. This specification applies only to new insulating oil as received prior to any processing.

1.3 The values stated in SI units are to be regarded as standard. No other units of measurement are included in this standard.

2. Referenced Documents

2.1 *ASTM Standards:*[3]

D88 Test Method for Saybolt Viscosity

D92 Test Method for Flash and Fire Points by Cleveland Open Cup Tester

D97 Test Method for Pour Point of Petroleum Products

D445 Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and Calculation of Dynamic Viscosity)

D611 Test Methods for Aniline Point and Mixed Aniline Point of Petroleum Products and Hydrocarbon Solvents

D877 Test Method for Dielectric Breakdown Voltage of Insulating Liquids Using Disk Electrodes

D923 Practices for Sampling Electrical Insulating Liquids

D924 Test Method for Dissipation Factor (or Power Factor) and Relative Permittivity (Dielectric Constant) of Electrical Insulating Liquids

D971 Test Method for Interfacial Tension of Oil Against Water by the Ring Method

D974 Test Method for Acid and Base Number by Color-Indicator Titration

D1275 Test Method for Corrosive Sulfur in Electrical Insulating Oils

D1298 Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method

D1500 Test Method for ASTM Color of Petroleum Products (ASTM Color Scale)

D1524 Test Method for Visual Examination of Used Electrical Insulating Oils of Petroleum Origin in the Field

D1533 Test Method for Water in Insulating Liquids by Coulometric Karl Fischer Titration

D1816 Test Method for Dielectric Breakdown Voltage of Insulating Oils of Petroleum Origin Using VDE Electrodes

D1903 Practice for Determining the Coefficient of Thermal Expansion of Electrical Insulating Liquids of Petroleum Origin, and Askarels

D2112 Test Method for Oxidation Stability of Inhibited Mineral Insulating Oil by Pressure Vessel

D2300 Test Method for Gassing of Electrical Insulating Liquids Under Electrical Stress and Ionization (Modified Pirelli Method)

D2440 Test Method for Oxidation Stability of Mineral Insulating Oil

D2668 Test Method for 2,6-*di-tert*-Butyl- *p*-Cresol and 2,6-*di-tert*-Butyl Phenol in Electrical Insulating Oil by Infrared Absorption

D2717 Test Method for Thermal Conductivity of Liquids

D2766 Test Method for Specific Heat of Liquids and Solids

D3300 Test Method for Dielectric Breakdown Voltage of Insulating Oils of Petroleum Origin Under Impulse Conditions

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[1] This specification is under the jurisdiction of ASTM Committee D27 on Electrical Insulating Liquids and Gases and is the direct responsibility of Subcommittee D27.01 on Mineral.

Current edition approved Dec. 1, 2009. Published December 2009. Originally approved in 1976. Last previous edition approved in 2008 as D3487 – 08. DOI:10.1520/D3487-09.

[2] Refer to American National Standard C 57.106. Guide for Acceptance and Maintenance of Insulating Oil in Equipment (IEEE Standard 64). Available from American National Standards Institute (ANSI), 25 W. 43rd St., 4th Floor, New York, NY 10036, http://www.ansi.org.

[3] For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

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D4059 Test Method for Analysis of Polychlorinated Biphenyls in Insulating Liquids by Gas Chromatography
D4768 Test Method for Analysis of 2,6-Ditertiary-Butyl Para-Cresol and 2,6-Ditertiary-Butyl Phenol in Insulating Liquids by Gas Chromatography
D5837 Test Method for Furanic Compounds in Electrical Insulating Liquids by High-Performance Liquid Chromatography (HPLC)

3. Terminology Definitions

3.1 *Type I Mineral Oil*—an oil for apparatus where normal oxidation resistance is required. Some oils may require the addition of a suitable oxidation inhibitor to achieve this.

3.2 *Type II Mineral Oil*—an oil for apparatus where greater oxidation resistance is required. This is usually achieved with the addition of a suitable oxidation inhibitor.

NOTE 1—During processing of inhibited mineral oil under vacuum and elevated temperatures, partial loss of inhibitor and volatile portions of mineral oil may occur. The common inhibitors, 2,6-ditertiary-butyl para-cresol (DBPC/BHT) and 2,6-ditertiary-butyl phenol (DPB), are more volatile than transformer oil. If processing conditions are too severe, oxidation stability of the oil may be decreased due to loss of inhibitor. The selectivity for removal of moisture and air in preference to loss of inhibitor and oil is improved by use of a low processing temperature.

Conditions that have been found satisfactory for most inhibited mineral oil processing are:

	Minimum Pressure	
Temperature, °C	Pa	Torr, Approximate
40	5	0.04
50	10	0.075
60	20	0.15
70	40	0.3
80	100	0.75
90	400	3.0
100	1000	7.5

If temperatures higher than those recommended for the operating pressure are used, the oil should be tested for inhibitor content and inhibitor added as necessary to return inhibitor content to its initial value. Attempts to dry apparatus containing appreciable amounts of free water may result in a significant loss of inhibitor even at the conditions recommended above.

3.3 *additives*—chemical substances that are added to mineral insulating oil to achieve required functional properties.

3.4 *properties*—those properties of the mineral insulating oil which are required for the design, manufacture, and operation of the apparatus. These properties are listed in Section 5.

4. Sampling and Testing

4.1 Take all oil samples in accordance with Test Methods D923.

4.2 Make each test in accordance with the latest revision of the ASTM test method specified in Section 5.

4.3 The oil shall meet the requirements of Section 5 at the unloading point.

NOTE 2—Because of the different needs of the various users, items relating to packaging, labeling, and inspection are considered to be subject to buyer-seller agreement.

NOTE 3—In addition to all other tests listed herein, it is sound engineering practice for the apparatus manufacturer to perform an evaluation of new types of insulating oils in insulation systems, prototype structures, or full-scale apparatus, or any combination thereof, to assure suitable service life.

4.4 Make known to the user the generic type and amount of any additive used, for assessing any potential detrimental reaction with other materials in contact with the oil.

5. Property Requirements

5.1 Mineral insulating oil conforming to this specification shall meet the property limits given in Table 1. The significance of these properties is discussed in Appendix X2.

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TABLE 1 Property Requirements

Property	Limit		ASTM Test Method
	Type I	Type II	
Physical:			
Aniline point, °C, min	63[A]	63[A]	D611
Color, max	0.5	0.5	D1500
Flash point, min, °C	145	145	D92
Interfacial tension at 25°C, min, dynes/cm	40	40	D971
Pour point, max, °C	−40[B]	−40[B]	D97
Relative Density (Specific gravity), 15°C/15°C max	0.91	0.91	D1298
Viscosity, max, cSt (SUS) at:			
100°C	3.0 (36)	3.0 (36)	D445 or D88
40°C	12.0 (66)	12.0 (66)	
0°C	76.0 (350)	76.0 (350)	
Visual examination	clear and bright	clear and bright	D1524
Electrical:			
Dielectric breakdown voltage at 60 Hz:			
Disk electrodes, min, kV	30	30	D877
VDE electrodes, min, kV 0.040-in. (1.02-mm) gap	20[C]	20[C]	D1816
0.080-in. (2.03-mm) gap	35[C]	35[C]	
Dielectric breakdown voltage, impulse conditions			D3300
25°C, min, kV, needle negative to sphere grounded, 1-in. (25.4-mm) gap	145[D]	145[D]	
Gassing tendency, max, µL/min	+30	+30	D2300
Dissipation factor (or power factor), at 60 Hz max, %:			D924
25°C	0.05	0.05	
100°C	0.30	0.30	
Chemical:[E]			
Oxidation stability (acid-sludge test)			D2440
72 h:			
% sludge, max, by mass	0.15	0.1	
Total acid number, max, mg KOH/g	0.5	0.3	
164 h:			
% sludge, max, by mass	0.3	0.2	
Total acid number, max, mg KOH/g	0.6	0.4	
Oxidation stability (rotating bomb test), min, minutes	—	195	D2112
Oxidation inhibitor content, max, % by mass	0.08[F]	0.3	D4768 or D2668[G]
Corrosive sulfur	noncorrosive		D1275
Water, max, ppm	35	35	D1533
Neutralization number, total acid number, max, mg KOH/g	0.03	0.03	D974
PCB content, ppm	not detectable	not detectable	D4059

[A] The value shown represents current knowledge.

[B] It is common practice to specify a lower or higher pour point, depending upon climatic conditions.

[C] These limits by Test Method D1816 are applicable only to as received new oil (see Appendix X2.2.1.2). A new processed oil should have minimum breakdown strengths of 28 kV and 56 kV for a 0.04 in. (1.02 mm) or 0.08 in. (2.03 mm) gap respectively.

[D] Currently available oils vary in impulse strength. Some users prefer oil of a 145 kV minimum for certain applications, while others accept oil with impulse strength as low as 130 kV for other applications.

[E] Furanic compounds, as determined by Test Method D5837, are useful for assessing the level of cellulose degradation that has occurred in oil impregnated paper systems. Specifying maximum allowable furan levels in new oils for this purpose should be by agreement between user and supplier.

[F] Provisions to purchase totally uninhibited oil shall be negotiated between producer and user.

[G] Both 2,6-ditertiary-butyl para-cresol (DBPC/BHT) and 2,6-ditertiary butylphenol (DBP) have been found to be suitable oxidation inhibitors for use in oils meeting this specification.

Preliminary studies indicate both Test Methods D2668 and D4768 are suitable for determining concentration of either inhibitor or their mixture.

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APPENDIXES

(Nonmandatory Information)

X1. SUPPLEMENTARY DESIGN INFORMATION

X1.1 The following values are typical for presently used mineral insulating oils. For oils derived from paraffinic or mixed-base crudes, the apparatus designer needs to know that these properties have not changed.

Property	Typical Values	ASTM Test Method
Coefficient of expansion,/° C from 25 to 100°C	0.0007 to 0.0008	D1903
Dielectric constant, 25°C	2.2 to 2.3	D924
Specific heat, cal/g, 20°C	0.44	D2766
Thermal conductivity, cal/cm·s·°C, from 20 to 100°C	$(0.30 \text{ to } 0.40) \times 10^{-3}$	D2717

X2. SIGNIFICANCE OF PROPERTIES OF MINERAL INSULATING OIL

X2.1 Physical Properties

X2.1.1 *Aniline Point*—The aniline point of a mineral insulating oil indicates the solvency of the oil for materials that are in contact with the oil. It may relate to the impulse and gassing characteristics of the oil.

X2.1.2 *Color*—A low color number is an essential requirement for inspection of assembled apparatus in the tank. An increase in the color number during service is an indicator of deterioration of the mineral insulating oil.

X2.1.3 *Flash Point*—The safe operation of the apparatus requires an adequately high flash point.

X2.1.4 *Interfacial Tension*—A high value for new mineral insulating oil indicates the absence of undesirable polar contaminants. This test is frequently applied to service-aged oils as an indicator of the degree of deterioration.

X2.1.5 *Pour Point*—The pour point of mineral insulating oil is the lowest temperature at which the oil will just flow and many of the factors cited under viscosity apply. The pour point of – 40°C may be obtained by the use of suitable distillates, refining processes, the use of appropriate long life additives, or any combination thereof. If a pour point additive is used, it is necessary to make known the amount and chemical composition.

X2.1.6 *Relative Density (Specific Gravity)*—The specific gravity of a mineral insulating oil influences the heat transfer rates and may be pertinent in determining suitability for use in specific applications. In extremely cold climates, specific gravity has been used to determine whether ice, resulting from freezing of water in oil-filled apparatus, will float on the oil and possibly result in flashover of conductors extending above the oil level. See, for example, "The Significance of the Density of Transformer Oils."[4]

X2.1.7 *Viscosity*—Viscosity influences the heat transfer and, consequently, the temperature rise of apparatus. At low temperatures, the resulting higher viscosity influences the speed of moving parts, such as those in power circuit breakers, switchgear, load tapchanger mechanisms, pumps, and regulators. Viscosity controls mineral insulating oil processing conditions, such as dehydration, degassification and filtration, and oil impregnation rates. High viscosity may adversely affect the starting up of apparatus in cold climates (for example, spare transformers and replacements).

X2.1.8 *Visual Examination*—A simple visual inspection of mineral insulating oil may indicate the absence or presence of undesirable contaminants. If such contaminants are present, more definitive testing is recommended to assess their effect on other functional properties.

X2.2 Electrical Properties

X2.2.1 *Dielectric Breakdown Voltage, 60 Hz*—The dielectric breakdown voltage of a mineral insulating oil indicates its ability to resist electrical breakdown at power frequencies in electrical apparatus.

X2.2.1.1 *Dielectric Breakdown—Disk Electrodes*—The test utilizing disk electrodes is useful in assessing the quality of the mineral insulating oil as received in tank cars, tank trucks, or drums. It is not sensitive enough to determine if an oil meets the minimum acceptable breakdown strength needed for processed oil used in some equipment.

X2.2.1.2 *Dielectric Breakdown—VDE Electrodes*—The VDE method (Test Method D1816) is sensitive to contaminants, such as water, dissolved gases, cellulose fibers, and conductive particles in oil. Processing involves filtering, dehydration, and degassing, which generally improve the breakdown strength of the oil. As a general guide, the moisture and dissolved gas content by volume in processed oils should be less 15 ppm and 0.5 % respectively. The minimum breakdown strength for as received oils is typically lower than that of processed oils because of higher levels of contaminants.

X2.2.2 *Dielectric Breakdown Voltage–Impulse*—The impulse strength of oil is critical in electrical apparatus. The impulse breakdown voltage of an oil indicates its ability to resist electrical breakdown under transient voltage stresses (lightning and switching surges). The functional property is sensitive to both polarity and electrode geometry.

X2.2.3 *Dissipation Factor*—Dissipation factor (power factor) is a measure of the dielectric losses in an oil. A low

[4] Mulhall, V. R., "The Significance of the Density of Transformer Oils,'' *IEEE Transactions on Electrical Insulation*, Vol 15, No. 6, December 1980, pp. 498–499. DOI: 10.1520/D3487-09_WIP_#872079.

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dissipation factor indicates low dielectric losses and a low level of soluble contaminants.

X2.3 Chemical Properties

X2.3.1 *Oxidation Inhibitor Content*—Oxidation inhibitor added to mineral insulating oil retards the formation of oil sludge and acidity under oxidative conditions. It is important to know if an oxidation inhibitor has been added to the oil and the amount. 2,6-Ditertiary-butyl para-cresol and 2,6-ditertiary butylphenol have been found suitable for use in mineral insulating oils complying with this specification. It is anticipated that other oxidation inhibitors will be accepted.

X2.3.2 *Corrosive Sulfur*—The absence of elemental sulfur and thermally unstable sulfur-bearing compounds is necessary to prevent the corrosion of certain metals such as copper and silver in contact with the mineral insulating oil.

X2.3.3 *Water Content*—A low water content of mineral insulating oil is necessary to achieve adequate electrical strength and low dielectric loss characteristics, to maximize the insulation system life, and to minimize metal corrosion.

X2.3.4 *Neutralization Number*—A low total acid content of a mineral insulating oil is necessary to minimize electrical conduction and metal corrosion and to maximize the life of the insulation system.

X2.3.5 *Oxidation Stability*—The development of oil sludge and acidity resulting from oxidation during storage, processing, and long service life should be held to a minimum. This minimizes electrical conduction and metal corrosion, maximizes insulation system life and electrical breakdown strength, and ensures satisfactory heat transfer. The limiting values in accordance with Table 1, as determined by Test Methods D2112 and D2440, best achieve these objectives.

X2.3.6 *Gassing*—The gassing tendency of a mineral insulating oil is a measure of the rate of absorption or desorption of hydrogen into or out of the oil under prescribed laboratory conditions. It reflects, but does not measure, aromaticity of the oil. Most oil-filled transformers are blanketed with nitrogen or oxygen-depleted air. The gassing tendency of oil under nitrogen does not directly relate to its gassing tendency under hydrogen. No quantitative relationship has been established between the gassing tendency of an oil, as indicated by the results of Test Method D2300, and the performance or life of that oil in service.

X2.3.7 *PCB Content*—United States regulations specify procedures to be followed for the use and disposal of electrical apparatus and electrical insulating fluids containing PCB (polychlorinated biphenyls). The procedure to be used for a particular apparatus or lot of insulating fluid is determined from its PCB content. New mineral insulating oil of the type covered by this specification should not contain any detectable PCB. A nondetectable PCB concentration measured by Test Method D4059 provides documentation to permit the insulating oil and apparatus containing it to be used without the labeling, recordkeeping, and disposal restrictions required of PCB-containing materials.

X3. CRUDE OILS, REFINING PROCESSES, AND SHIPPING CONTAINERS

X3.1 *Crude Oils*—Mineral insulating oils are presently refined from predominantly naphthenic crude oils. As the supply of such crude oils diminishes, paraffinic or mixed base crudes may be used to provide mineral insulating oil for use in electrical apparatus. As the new crudes are developed for this use, additional tests peculiar to the chemistry of these oils will need to be defined.

X3.2 *Refining Processes*—Distillates from crude oils may be refined by various processes such as solvent extraction, dewaxing, hydrogen treatment, or combinations of these methods to yield mineral insulating oil meeting the requirements of this specification. The generic process should be specified upon request.

X3.3 *Shipping Containers*—Mineral insulating oil is usually shipped in rail cars, tank trucks (trailers), or drums. Rail cars used for shipping mineral insulating oil are usually not used for shipping other products and are more likely to be free of contamination. Tank trucks may be used for many different products and are more subject to contamination. Oil drums are most often used for shipping small quantities. All shipping containers, together with any attendant pumps and piping, should be cleaned prior to filling with oil and should be properly sealed to protect the oil during shipment.

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