# CAPCOA GHG Rx Protocol:

## Climate Action Reserve U.S. Livestock Project Protocol Version 4.0 (January 23, 2013)

Approved by the CAPCOA Board February 8, 2017

## The following conditions apply for use in the CAPCOA GHG Rx:

1. **Projects must be located in California**
2. **Projects must commence on or after 1/1/07 or 1/1/05 for reductions covered by San Joaquin Valley APCD Rule 2301**

# U.S. Livestock Project Protocol
# Version 4.0
## ERRATA AND CLARIFICATIONS

The Climate Action Reserve (Reserve) published its U.S. Livestock Project Protocol Version 4.0 (LSPP V4.0) in January 2013. While the Reserve intends for the LSPP V4.0 to be a complete, transparent document, it recognizes that correction of errors and clarifications will be necessary as the protocol is implemented and issues are identified. This document is an official record of all errata and clarifications applicable to the LSPP V4.0.[1]

Per the Reserve's Program Manual, both errata and clarifications are considered effective on the date they are first posted on the Reserve website. The effective date of each erratum or clarification is clearly designated below. All listed and registered livestock projects must incorporate and adhere to these errata and clarifications when they undergo verification. The Reserve will incorporate both errata and clarifications into future versions of the protocol.

All project developers and verification bodies must refer to this document to ensure that the most current guidance is adhered to in project design and verification. Verification bodies shall refer to this document immediately prior to uploading any Verification Statement to assure all issues are properly addressed and incorporated into verification activities.

If you have any questions about the updates or clarifications in this document, please contact Policy at policy@climateactionreserve.org or (213) 891-1444 x3.

[1] See Section 4.3.4 of the Climate Action Reserve Program Manual for an explanation of the Reserve's policies on protocol errata and clarifications. "Errata" are issued to correct typographical errors. "Clarifications" are issued to ensure consistent interpretation and application of the protocol. For document management and program implementation purposes, both errata and clarifications are contained in this single document.

# Errata and Clarifications (arranged by protocol section)

# Section 3

## 1. Regulatory Compliance at Centralized Digesters (CLARIFICATION – July 21, 2016)

**Section:** 3.6 (Regulatory Compliance)

**Context:** This section states that, where a verifier determines that project activities have caused a material violation, no CRTs will be issued during the period(s) when the violation occurred. The guidance in this section does not specify how to address regulatory compliance for projects where manure is received from multiple farms and managed in a centralized BCS.

It is unclear whether a violation with respect to one manure source facility would jeopardize the ability of the project to receive credit from emission reductions related to manure from other source facilities. It may be possible for an offset project at a centralized digester to have CRTs issued to it for manure from compliant manure source facilities during a period of time when one or more manure source facilities are materially noncompliant with a regulation.

**Clarification:** The following text shall be inserted on page 7, at the end of Section 3.6:

"With respect to projects that accept and manage manure from multiple, discrete source facilities (separate from the project BCS in both physical location and management), it may be possible for a project developer to demonstrate that a regulatory violation at one source facility does not affect the eligibility of the entire project under this section. Project developers should contact the Reserve to discuss potential regulatory non-compliance issues."

# Section 5

## 2. Accounting for Methane Emissions during Temporary Project Shutdown (CLARIFICATION – October 29, 2013)

**Section:** 5.3 (Calculating Project Methane Emissions)

**Context:** The last full paragraph on page 24 reads: "Although not common under normal digester operation, it is possible that a venting event may occur due to catastrophic failure of digester cover materials, the digester vessel, or the gas collection system. In the event that a catastrophic system failure results in the venting of biogas, the quantity of methane released to the atmosphere shall be estimated according to Equation 5.7 below."

Equation 5.7 on page 26 provides guidance for calculating the quantity of methane released during a venting event, which is added to the total Project Methane Emissions from the BCS, as calculated in Equation 5.6. Equation 5.7 accounts for two releases of biogas: the initial release of biogas being stored in the digester, and then the daily release of additional gas that is generated in the digester until the gas collection system is functional.

The intent of the current guidance is to account for situations where the project digester continues to receive and treat manure, but the gas collection system is discovered to be compromised. In situations where the project digester has been shut down for longer periods of time, biogas is typically released from the digester and then project manure directed to an anaerobic system (e.g. either the covers are taken off the digester or manure is diverted to open lagoons) that would meet the definition in Section 3.4. During such longer shutdowns, it has not been clear whether this entire period of time should be considered a venting event and, if so, how quantification of emissions should proceed.

**Clarification:** The following text shall be inserted between Equation 5.7 and Equation 5.8 on page 26:

"A venting event occurs when the project digester continues to process manure, but biogas is vented directly to the atmosphere (e.g. through a rip in a lagoon cover or a broken pipe). Projects that experience a venting event shall continue to use Equation 5.7 to calculate the resulting project methane emissions.

A project shutdown occurs when the project digester is no longer functional. This occurs when the project reverts to an open, uncontrolled, anaerobic manure treatment system (e.g. the manure is redirected to open, anaerobic lagoons, or the cover is completely removed from a covered lagoon digester and no heating or mixing occurs). A project shutdown is defined as a venting event on the day of the shutdown, and then a cessation of project operations until the BCS is once again operable.

In the case where the project BCS is shut down and the manure is treated in an open, uncontrolled, anaerobic system (meeting the definition in Section 3.4), the project scenario shall be assumed to be equal to the baseline scenario. In this case the project must quantify the release of stored biogas ($MS_{BCS}$ in Equation 5.7) at the time that the system is shut down, but not the subsequent daily release of biogas from the open lagoons. In these situations the project will cease quantification of emission reductions until the BCS is once again operational."

## 3. Service Providers for Site-Specific Destruction Efficiency Testing (CLARIFICATION – January 21, 2014)

**Section:** 5.3 (Calculating Project Methane Emissions)

**Context:** Footnote 19 on page 25 provides guidelines for service provider accreditation. It is not clear what specific options are available and permissible for projects located in a state or locality which does not have an accreditation program for source test service providers. Footnote 26 on page 29 and the first full paragraph on page 69 in Appendix B contain similar language.

**Clarification:** The intent of this requirement is to ensure that any source testing conducted for the determination of a site-specific value for methane destruction efficiency is of a quality that would be acceptable for compliance by a regulatory body. The following text shall replace the last sentence of footnote 19 on page 25, of footnote 26 on page 29, and of the first full paragraph on page 69 of Appendix B:

> "If neither the state nor locality relevant to the project site offer accreditation for source testing service providers, projects may use an accredited service provider from another U.S. state or domestic locality. Alternatively, projects may choose a non-accredited service provider, under the following conditions: 1) the service provider must provide verifiable evidence of prior testing which was accepted for compliance by a domestic regulatory agency, and 2) the prior testing procedures must be substantially similar to

the procedures used for determining methane destruction efficiency for the project destruction device(s)."

# Section 6

## 4. Monitoring Operational Status (CLARIFICATION – October 29, 2013)

**Section:** 6.2 (Biogas Control System Monitoring Requirements)

**Context:** The first and second paragraphs of page 35 in Section 6.2 states that "[o]perational activity of the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. … If for any reason the destruction device or the operational monitoring equipment…is inoperable, then all metered biogas going to the particular device shall be assumed to be released to atmosphere…[and] the destruction efficiency of the device must be assumed to be zero."

Certain types of destruction devices, such as internal combustion engines and most large boiler systems, are designed in such a way that gas may not flow through the device if it is not operational. It has not been clear how the requirements of Section 6.2 apply to these devices.

**Clarification:** The first sentence of the first paragraph on page 35 shall be read to apply to all destruction devices in use during the reporting period. The paragraph on page 34 of Section 6.2 starting, "[a] single flow meter may be used…," shall not be construed to relax the requirement for hourly operational data for all destruction devices. Rather, that paragraph is allowing a specific metering arrangement during periods when one or more devices are known to be not operating. All destruction devices must have their operational status monitored and recorded at least hourly. If these data are missing or never recorded for a particular device, that device will be assumed to be not operating and will be assigned a destruction efficiency of zero for all flow data that are assigned to that device.

## 5. Meter Field Check Procedures (CLARIFICATION – October 29, 2013)

**Section:** 6.3 (Biogas Measurement Instrument QA/QC)

**Context:** The second paragraph below the first bulleted list of page 36 in Section 6.3 states that "[i]f the field check on a piece of equipment reveals accuracy outside of a +/- 5% threshold, calibration by the manufacturer or a certified service provider is required for that piece of equipment…"

Certain types of biogas flow meters and methane analyzers are susceptible to measurement drift due to buildup of moisture or contaminants on the metering sensor, even if the equipment itself is not out of calibration. If the as-found condition of the meter is outside of the accuracy threshold, but the as-left condition (after cleaning) is within the accuracy threshold, it is not clear whether a full calibration is still required for this piece of equipment. In some cases the manufacturer provides specific guidance to this effect.

**Clarification:** The following text shall be inserted after the second paragraph following the bulleted list on page 36:

"The as-found condition (percent drift) of a field check must always be recorded. If the meter is found to be measuring outside of the +/- 5% threshold for accuracy, the data must be adjusted for the period beginning with the last successful field check or calibration event up until the meter is confirmed to be in calibration. If, at the time of the failed field check, the meter is cleaned and checked again, with the as-left condition found to be within the accuracy threshold, a full calibration is not required for that piece of equipment. This shall be considered a failed field check, followed by a successful field check. The data adjustment shall be based on the percent drift recorded at the time of the failed field check. However, if the as-left condition remains outside of the +/- 5% accuracy threshold, calibration is required by the manufacturer or a certified service provider for that piece of equipment."

# Appendix D

## 6. Data Substitution when Operational Data are Missing (ERRATUM – October 29, 2013)

**Section:** Appendix D (Data Substitution)

**Context:** There are three parameters necessary for the quantification of biogas destruction: biogas flow volume, methane concentration, and operational status of the destruction device. Section D.1 on page 80 provides a methodology for the substitution of missing biogas flow or methane concentration data. Data on the operational status of a destruction device are not eligible for substitution. Substitution of one parameter (i.e. flow or concentration) is only allowed if both other parameters are successfully recorded during the data gap. Thus, to employ the data substitution methodology, it is required that the record of operational status be intact during the gap.

This data substitution methodology was originally developed to resolve incidents of missing methane destruction data in landfill gas projects. Under that project type, excluding the data gap entirely is equivalent to the use of a destruction efficiency (DE) value of zero, whereas the same is not true for a livestock project. In the case of the Livestock Project Protocol, there is additional guidance on page 35 of Section 6.2 that requires the use of a DE value of zero for periods where the destruction device is inoperable, or the operational data are missing. This procedure effectively provides substitution of missing operational data with the assumption that the device was inoperable during the data gap. The effect of this substitution is an increase in project emissions, resulting in a more conservative estimate of emission reductions, regardless of whether the ultimate estimate of emission reductions is based on the modeled baseline or the metered methane destruction.

Because of the nature of the quantification methodology for livestock projects, and the ways that it differs from that of landfill projects, it is appropriate and conservative to carry out flow or methane data substitution, even if the destruction device is inoperable. Under this protocol, the quantification of emission reductions will be more conservative than if the data substitution were not employed.

**Correction:** The guidance on page 35 of Section 6.2 shall supersede the guidance in Appendix D. The following text shall be inserted after the second paragraph of Section D.1 in Appendix D:

"If the destruction device is inoperable, or its operational data are missing, the destruction efficiency for the device shall be zero during that period of time. Data substitution may be employed for missing biogas flow or methane concentration data during periods of missing operational data, provided the dataset is able to fulfill all other requirements of this data substitution methodology. The data substitution methodology shall be employed in the manner resulting in the greatest level of conservativeness for the quantification of emission reductions."

## 7. Data Substitution for Continuous Methane Data (CLARIFICATION – October 29, 2013)

**Section:** Appendix D (Data Substitution)

**Context:** The data substitution methodology in Appendix D may not be used for data gaps that are greater than seven days. However, the minimum measurement frequency for methane concentration data is once per quarter (three months). For projects that measure methane concentration at a frequency that is greater than quarterly, it is not clear how methane values should be applied during gaps of more than one week but less than an entire quarter.

**Clarification:** As long as a livestock project has at least one methane concentration reading per quarter, the project may satisfy the monitoring requirements in Section 6.2. A livestock project may have gaps between methane concentration readings that are greater than one week without this being considered "missing data" as it is conceived in Appendix D. Thus, project developers may devise a reasonable approach by which to assign a value to periods of time between recorded methane concentration values. The verifier shall confirm that the value(s) applied by the project is reasonable and conservative. No data substitution may be applied if there are no methane concentration readings during an entire quarter.

CLIMATE ACTION RESERVE

Version 4.0 | January 23, 2013

# U.S. Livestock

## Project Protocol

Climate Action Reserve
601 West 5th Street, Suite 650
Los Angeles, CA 90071
www.climateactionreserve.org

Released January 23, 2013

# Acknowledgements

### Staff

Mike McCormick
Derek Markolf
Syd Partridge
Max DuBuisson
Sami Osman
Derik Broekhoff
Rachel Tornek
Heather Raven
Anna Schmitz

The Reserve would like to thank SAIC and Kathryn Bickel Goldman for their work on the performance standard analysis.

The Reserve also recognizes the workgroup for their generous contribution of time and expertise, as well as other members of the public who actively participated in the protocol development process.

### Workgroup

| | |
|---|---|
| Susan Wood | AgCert |
| William Salas | Applied Geosolutions |
| Patrick Gaffney | California Air Resources Board |
| Kitty Howard | California Air Resources Board |
| Doug Thompson | California Air Resources Board |
| Dan Weller | California Air Resources Board |
| Steve Schaffer | California Department of Food and Agriculture |
| Cynthia Cory | CA Farm Bureau |
| John Shears | CEERT |
| Suzy Friedman | Environmental Defense |
| Martha Davis | Inland Empire Utility Agency |
| Scott Leloni | Manitoba Agriculture, Food and Rural Initiatives |
| Allen Dusault | Sustainable Conservation |
| Michael Boccadoro | The Dolphin Group |
| Melissa Weitz | U.S. EPA |
| Frank Mitleohner | UC Davis |
| Paul Martin | Western United Dairymen |
| Paul Sousa | Western United Dairymen |

# Table of Contents

# List of Tables



# List of Figures



# List of Equations



# List of Appendix Tables

# Abbreviations and Acronyms

| | |
|---|---|
| BCS | Biogas control system |
| CARB | California Air Resources Board |
| $CH_4$ | Methane |
| CNG | Condensed natural gas |
| $CO_2$ | Carbon dioxide |
| CRT | Climate Reserve Tonne |
| EPA | U.S. Environmental Protection Agency |
| GHG | Greenhouse gas |
| GWP | Global warming potential |
| IPCC | Intergovernmental Panel on Climate Change |
| lb | Pound |
| LNG | Liquefied natural gas |
| MCF | Methane conversion factor |
| MT | Metric ton or tonne |
| $N_2O$ | Nitrous oxide |
| NG | Natural gas |
| QA/QC | Quality Assurance/Quality Control |
| Reserve | Climate Action Reserve |
| scf | Standard cubic foot at 1 atm pressure and 60°F temperature |
| SSR | Sources, sinks, and reservoirs |
| t | Metric ton or tonne |
| TAM | Typical animal mass |
| VS | Volatile solids |

# 1 Introduction

The Climate Action Reserve's (Reserve) Livestock Project Protocol provides guidance to account for and report greenhouse gas (GHG) emission reductions associated with the installation of a biogas control system (BCS) for manure management on dairy cattle and swine farms. The protocol focuses on quantifying the change in methane emissions, but also accounts for potential increases in carbon dioxide emissions.

The Climate Action Reserve is the most experienced, trusted and efficient offset registry to serve the California cap-and-trade program and the voluntary carbon market. With deep roots in California and a reach across North America, the Reserve encourages actions to reduce greenhouse gas emissions and works to ensure environmental benefit, integrity and transparency in market-based solutions to address global climate change. It operates the largest accredited registry for the California compliance market and has played an integral role in the development and administration of the state's cap-and-trade program. For the voluntary market, the Reserve establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies and issues and tracks the transaction of carbon credits (Climate Reserve Tonnes) generated from such projects in a transparent, publicly-accessible system. The Reserve program promotes immediate environmental and health benefits to local communities and brings credibility and value to the carbon market. The Climate Action Reserve is a private 501(c)(3) nonprofit organization based in Los Angeles, California.

Project developers that install manure biogas capture and destruction technologies use this document to register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive independent verification by Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Verification Program Manual and Section 8 of this protocol.

This project protocol facilitates the creation of GHG emission reductions determined in a complete, consistent, transparent, accurate, and conservative manner, while incorporating relevant sources.[1]

[1] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG accounting principles.

# 2 The GHG Reduction Project

Manure treated and stored under anaerobic conditions decomposes to produce methane, which, if uncontrolled, is emitted to the atmosphere. This predominantly occurs when livestock operations manage waste with anaerobic, liquid-based systems (e.g. in lagoons, ponds, tanks, or pits). Within the livestock sector, the primary drivers of methane generation include the amount of manure produced and the fraction of volatile solids (VS) that decompose anaerobically. Temperature and the retention time of manure during treatment and storage also affect methane production.

## 2.1 Project Definition

For the purpose of this protocol, the GHG reduction project is defined as the installation and operation of a biogas control system[2] that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations. The biogas control system must destroy methane gas that would otherwise have been emitted to the atmosphere in the absence of the project from uncontrolled anaerobic treatment and/or storage of manure.

Captured biogas can be destroyed on-site, or transported for off-site use (e.g. through gas distribution or transmission pipeline), or used to power vehicles. Regardless of how project developers take advantage of the captured biogas, the ultimate fate of the methane must be destruction.

“Centralized digesters” that integrate waste from more than one livestock operation also meet the definition of a GHG reduction project.

Note that the protocol does not preclude project developers from co-digesting organic matter in the biogas control system. However, the additional organics could impact the nutrient properties of digester effluent; project developers should consider this when assessing the project’s associated water quality impacts. The Reserve has also developed the Organic Waste Digestion Project Protocol that provides a quantification methodology for crediting the co-digestion of eligible waste streams with livestock manure. The protocol is available at http://www.climateactionreserve.org/how/protocols/adopted/organic-waste-digestion/current/.

## 2.2 The Project Developer

The “project developer” is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers could be livestock facility owners and operators, GHG project financiers, or other entities. The project developer must have clear ownership of the project’s GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership each time the project is verified by signing the Reserve’s Attestation of Title form.[3]

Under this protocol, the project developer is the only party required to be involved with project implementation.

[2] Biogas control systems encompass anaerobic digester systems – which may be designed and operated in a variety of ways, from ambient temperature covered lagoons to heated lagoons to mesophilic plug flow or complete mix concrete tank digesters—as well as methane destruction systems, such as flares or engines.
[3] Attestation of Title form available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

# 3 Eligibility Rules

Project developers using this protocol must satisfy the following eligibility rules to register reductions with the Reserve. The criteria only apply to projects that meet the definition of a GHG reduction project.

| | | | |
|---|---|---|---|
| **Eligibility Rule I:** | Location | ⟶ | *U.S., its territories, and tribal lands* |
| **Eligibility Rule II:** | Project Start Date | ⟶ | *No more than 6 months prior to project submission* |
| **Eligibility Rule III:** | Anaerobic Baseline | ⟶ | *Demonstrate anaerobic baseline conditions* |
| **Eligibility Rule IV:** | Additionality | ⟶ | *Meet performance standard* |
| | | ⟶ | *Exceed regulatory requirements* |
| **Eligibility Rule V:** | Regulatory Compliance | ⟶ | *Compliance with all applicable laws* |

## 3.1 Location

Only projects located in the United States and its territories, or on U.S. tribal lands, are eligible to register reductions with the Reserve under this protocol. Livestock projects located in Mexico must use the Mexico Livestock Project Protocol if seeking to register GHG reductions with the Reserve.

## 3.2 Project Start Date

The start date for a livestock project is defined as the date on which the project's biogas control system becomes operational. For the purposes of this protocol, a BCS is considered *operational* on the date that the system begins producing and destroying methane gas following an initial start-up period. This date can be selected by the project developer within the 6 month period following the date on which manure is first loaded into the digester or on the date that the cover installation was completed (for a covered lagoon digester where the lagoon already contained manure).

Projects must be submitted to the Reserve no more than six months after the project start date.

## 3.3 Project Crediting Period

Project developers are eligible to register GHG reductions with the Reserve according to this protocol for a period of ten years following the project's start date. All projects that initially pass the eligibility requirements set forth in this protocol are eligible to register GHG reductions with the Reserve for the duration of the project's first crediting period (ten years), even if a regulatory agency with authority over a livestock operation passes a rule obligating the installation of a BCS during this initial crediting period.

If a project developer wishes to apply for eligibility under a second crediting period, they must do so within the final six months of the initial crediting period. Thus, the Reserve may issue CRTs for GHG reductions quantified and verified according to the U.S. Livestock Project Protocol for a maximum of two ten year crediting periods after the project start date. Section 3.5.1 and 3.5.2 describe the requirements to qualify for a second crediting period. Deadlines and requirements for reporting and verification, as laid out in this protocol, the Program Manual, and the Verification Program Manual, will continue to apply without interruption.

## 3.4 Uncontrolled Anaerobic Baseline

The installation of a BCS at a livestock operation where the primary manure management system is aerobic (produces little to no methane) may result in an increase of the amount of methane emitted to the atmosphere. Thus, the BCS must digest manure that would primarily be treated in an anaerobic system in the absence of the project in order for the project to meet the definition of a GHG reduction project. Sections 3.4.1, 3.4.2, and 3.4.3 explain the specific baseline scenario options. Under any one of these scenarios, the uncontrolled anaerobic baseline requirement may be temporarily disrupted for the purposes of construction of the project digester. In these cases, the verifier may use professional judgment to confirm that the requirements of this section have been met.

### 3.4.1 Existing Livestock Facilities

For livestock facilities that have been in operation for more than five years, developers of livestock projects must demonstrate that an uncontrolled anaerobic manure management system was in place for the five years immediately prior to the date that manure was first loaded into the project digester. That anaerobic system may include a lagoon or a pond as long as the depth of the system was sufficient to prevent algal oxygen production and create an oxygen-free bottom layer (i.e. greater than 1 meter in liquid depth).[4]

For livestock facilities that have been in operation for more than two years, but less than five years, developers of livestock projects must demonstrate that an uncontrolled anaerobic manure management system was in place at all times up until the project's start date.

### 3.4.2 New Livestock Facilities (Greenfields)

Greenfield livestock projects (i.e. projects that are implemented at livestock facilities that have been in operation for less than two years at a site that had no prior manure management infrastructure) are eligible only if the project developer can demonstrate that there are no restrictions to the construction and operation of an open, uncontrolled, anaerobic manure storage system. Since a greenfield project will not have an existing manure management system that can be used to model the baseline methane emissions, all greenfield projects shall utilize a set of standardized baseline management assumptions (see Table B.10).

### 3.4.3 Centralized Digesters

For projects that employ a centralized digester that will be accepting manure from more than one livestock operation, each individual source of manure (identified by livestock facility) must meet the anaerobic baseline requirements above as of the project start date. In other words, if a new facility begins sending manure to the project digester after the project start date, the anaerobic baseline of that manure must still be assessed as of the project start date.

[4] This is consistent with the United Nations Framework Convention on Climate Change (UNFCCC) Clean Development Mechanism (CDM) methodology ACM00010 (available at: http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html). For additional information on the design and maintenance of anaerobic wastewater treatment systems, see U.S. Department of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Waste Storage Facility, No. 313; and U.S. Department of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Waste Treatment Lagoon, No. 359.

## 3.5 Additionality

The Reserve will only accept projects that yield surplus GHG reductions that are additional to what would have otherwise occurred. That is, the reductions are above and beyond business-as-usual operation.

Project developers satisfy the "additionality" eligibility rule by passing two tests:

1. The Performance Standard Test
2. The Legal Requirement Test

### 3.5.1 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a program-wide performance threshold – i.e. a standard of performance applicable to all manure management projects, established on an *ex-ante* basis. The performance threshold represents "better than business-as-usual" manure management. If the project meets the threshold, then it exceeds what would happen under the business-as-usual scenario and generates surplus/additional GHG reductions.

For this protocol, the Reserve uses a technology-specific threshold; sometimes also referred to as a practice-based threshold, where it serves as "best-practice standard" for managing livestock manure. By installing a BCS, a project developer passes the Performance Standard Test.

The Reserve defined this performance standard by evaluating manure management practices in California and the United States. A summary of the study to establish the threshold is provided in Appendix C.

The Performance Standard Test is applied at the time of the project's start date. All projects that pass this test at the project's start date are eligible to register reductions with the Reserve for the duration of the first project crediting period, even if the Reserve revises the Performance Standard Test in subsequent versions of this protocol during that period. As stated in Section 3.3, the project crediting period is ten years.

If a project developer wishes to apply for a second crediting period, the project must meet the eligibility requirements of the most current version of this protocol at the time of the submittal for the second crediting period, including any updates to the Performance Standard Test.

### 3.5.2 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the installation of a BCS at the livestock operation.

The Legal Requirement Test is applied at the time of a project's start date. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form[5] prior to the commencement of verification activities for the first verification

[5] Attestation forms are available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

period. All projects that pass this test at the project's start date are eligible to register reductions with the Reserve for the duration of their first crediting period, even if legal requirements change or new legal requirements are enacted during that period.

If a project developer wishes to apply for a second crediting period, the project must meet the eligibility requirements of the most current version of this protocol, including any updates to the Legal Requirement Test. Furthermore, during a project's second crediting period, it must demonstrate that it passes the Legal Requirement Test during each reporting period. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form prior to the commencement of verification activities for each verification period. If project activities become legally required during a project's second crediting period, the project will only be eligible to receive CRTs up to the date that the system is required to be operational.

The Reserve's analysis of manure management practices in the U.S. identified no regulations that obligate livestock owners to invest in a manure BCS. The analysis looked most closely at recent, stringent California air quality regulations (e.g. SJVAPCD Rule 4570 and Sacramento AQMD Rule 496), and found that installing an anaerobic digester is one of several compliance options, although high capital costs appear to prohibit the use of anaerobic digesters as a practical compliance mechanism for these air quality regulations.

## 3.6 Regulatory Compliance

As a final eligibility requirement, project developers must attest that project activities do not cause material violations of applicable laws (e.g. air, water quality, safety, etc.). To satisfy this requirement, project developers must submit a signed Attestation of Regulatory Compliance form[6] prior to the commencement of verification activities each time the project is verified. Project developers are also required to disclose in writing to the verifier any and all instances of legal violations – material or otherwise – caused by the project or project activities.

A violation should be considered to be "caused" by project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. If there is any question of causality, the project developer shall disclose the violation to the verifier.

If a verifier finds that project activities have caused a material violation, then CRTs will not be issued for GHG reductions that occurred during the period(s) when the violation occurred. Individual violations due to administrative or reporting issues, or due to "acts of nature," are not considered material and will not affect CRT crediting. However, recurrent administrative violations directly related to project activities may affect crediting. Verifiers must determine if recurrent violations rise to the level of materiality. If the verifier is unable to assess the materiality of the violation, then the verifier shall consult with the Reserve.

[6] Attestation forms are available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

# 4 The GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project developers to determine the net change in emissions associated with installing a BCS. This protocol's assessment boundary captures sources from waste production to disposal, including off-site manure disposal.

$CH_4$ emissions from the land application of manure and digester effluent are excluded from the GHG Assessment Boundary. As these emission sources will either remain the same or decrease from the baseline to the project scenario, this exclusion is considered to be conservative.

$N_2O$ emissions associated with manure management and disposal are also excluded from the GHG Assessment Boundary. Again, as these emission sources will either remain the same or decrease from the baseline to the project scenario, this exclusion is also considered to be conservative. Significant uncertainty remains regarding the quantification of potential $N_2O$ changes. While some projects may result in a significant decrease in $N_2O$ emissions, at this time there is no project-level methodology available to appropriately account for this uncertainty.

$CO_2$ emissions associated with the capture and destruction of biogas are considered biogenic emissions[7] (as opposed to anthropogenic) and are not included in the GHG Assessment Boundary.

This protocol does not account for $CO_2$ emission reductions associated with displacing grid-delivered electricity or fossil fuel use. However, project developers may reduce the project emissions associated with increased use of grid-connected electricity by utilizing project-generated electricity for project equipment.

Figure 4.1 provides a general illustration of the GHG Assessment Boundary, indicating which SSRs are included or excluded from the boundary. All SSRs within the dashed line are accounted for under this protocol.

Table 4.1 provides greater detail on each SSR and provides justification for the inclusion or exclusion of SSRs and gases from the GHG Assessment Boundary.

[7] The rationale is that carbon dioxide emitted during combustion represents the carbon dioxide that would have been emitted during natural decomposition of the manure. Emissions from the biogas control system do not yield a net increase in atmospheric carbon dioxide because they are theoretically equivalent to the carbon dioxide absorbed during plant/feed growth.

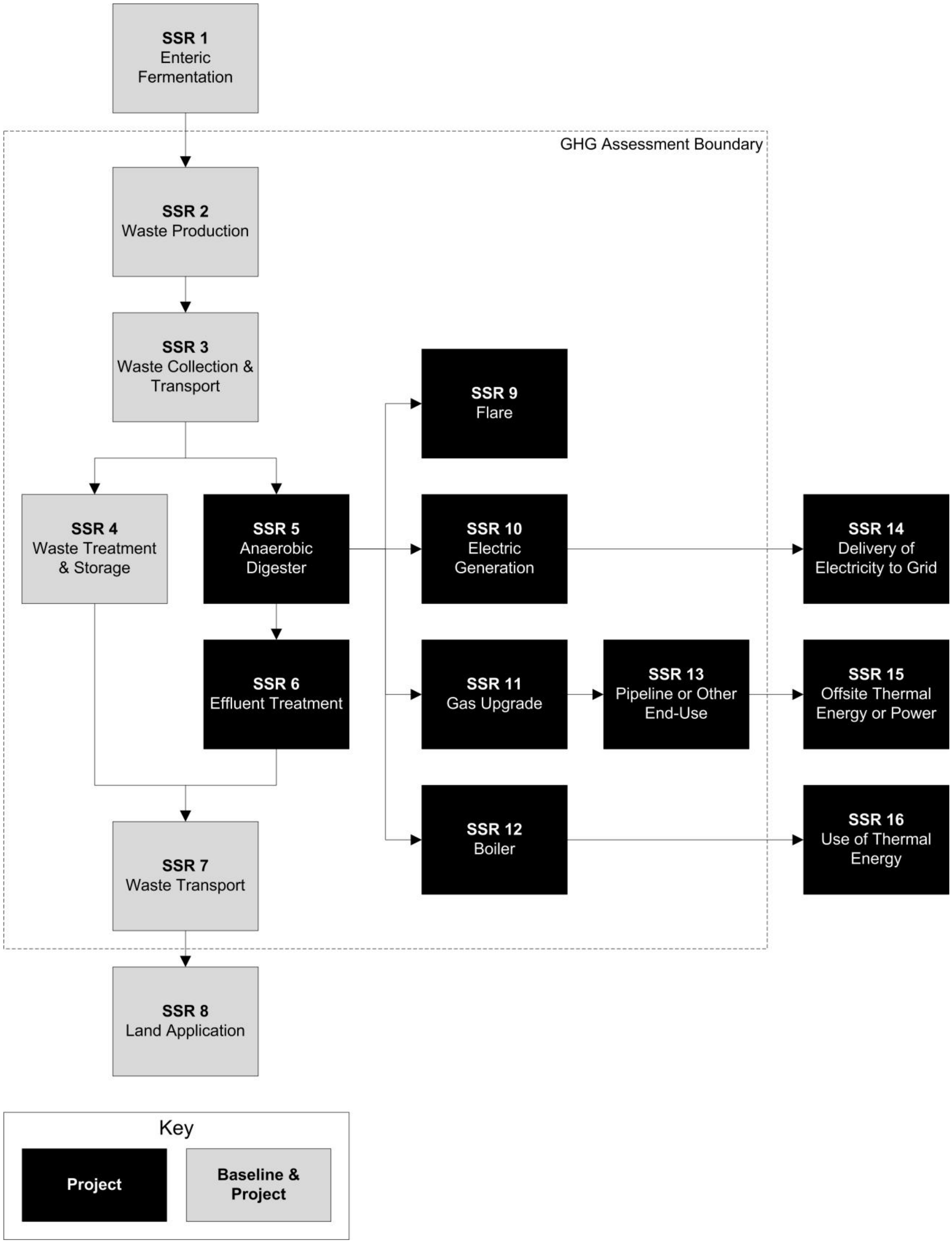



**Figure 4.1.** General Illustration of the GHG Assessment Boundary

Table 4.1 relates GHG source categories to sources and gases, and indicates inclusion in the calculation methodology. It is intended to be illustrative – GHG sources are indicative for the source category, GHGs in addition to the main GHG are also mentioned, where appropriate.

**Table 4.1.** Description of all Sources, Sinks, and Reservoirs

| SSR | GHG Source | Gas | Relevant to Baseline (B) or Project (P) | Included/ Excluded | Justification/Explanation |
|---|---|---|---|---|---|
| 1 | Emissions from enteric fermentation | $CH_4$ | B, P | *Excluded* | It is very unlikely that a livestock operation would change its feeding strategy to maximize biogas production from a digester; thus impacting enteric fermentation emissions from ruminant animals. |
| 2 | Emissions from waste deposits in barn, milking parlor or pasture/corral | $N_2O$ | B, P | *Excluded* | This exclusion is conservative as emissions will either remain the same or decrease from the baseline to the project scenario, see page 8 for further explanation. |
| | Emissions from mobile and stationary support equipment | $CO_2$ | B, P | *Included* | If any additional vehicles or equipment are required by the project beyond what is required in the baseline, emissions from such sources shall be accounted for. |
| | | $CH_4$ | | *Excluded* | Emission source is assumed to be very small. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 3 | Emissions from mechanical systems used to collect and transport waste (e.g. engines and pumps for flush systems; vacuums and tractors for scrape systems) | $CO_2$ | B, P | *Included* | If any additional vehicle or equipment use is required by the project beyond what is required in the baseline, emissions from such sources shall be accounted for. |
| | | $CH_4$ | | *Excluded* | Emission source is assumed to be very small. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| | Vehicle emissions (e.g. for centralized digesters) | $CO_2$ | | *Included* | If any additional vehicles or fuel use is required by the project beyond what is required in the baseline, emissions from such equipment shall be accounted for. |
| | | $CH_4$ | | *Excluded* | Emission source is assumed to be very small. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |

| SSR | GHG Source | Gas | Relevant to Baseline (B) or Project (P) | Included/ Excluded | Justification/Explanation |
|---|---|---|---|---|---|
| 4 | Emissions from waste treatment and storage including: anaerobic lagoons, dry lot deposits, compost piles, solid storage piles, manure settling basins, aerobic treatment, storage ponds, etc. | $CO_2$ | B, P | *Excluded* | Biogenic emissions are excluded. |
| | | $CH_4$ | | *Included* | Primary source of emissions in the baseline. |
| | | $N_2O$ | | *Excluded* | This exclusion is conservative as emissions will either remain the same or decrease from the baseline to the project scenario, see page 8 for further explanation. |
| | Emissions from support equipment | $CO_2$ | | *Included* | If any additional equipment is required by the project beyond what is required in the baseline, emissions from such equipment shall be accounted for. |
| | | $CH_4$ | | *Excluded* | Emission source is assumed to be very small. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 5 | Emissions from the anaerobic digester due to biogas collection inefficiencies and venting events | $CH_4$ | P | *Included* | Project may result in leaked emissions from anaerobic digester. |
| 6 | Emissions from effluent treatment system | $CH_4$ | P | *Included* | Primary source of emissions from project activities. |
| | | $N_2O$ | | *Excluded* | See page 8. |
| 7 | Vehicle emissions for land application and/or off-site transport | $CO_2$ | B, P | *Included* | If any additional vehicle use is required by the project beyond what is required in the baseline, associated additional emissions shall be accounted for. |
| | | $CH_4$ | | *Excluded* | Emission source is assumed to be very small. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 8 | Emissions from land application | $CH_4$ | B, P | *Excluded* | Project activity is unlikely to increase emissions relative to baseline activity. |
| | | $N_2O$ | B, P | *Excluded* | This exclusion is conservative as emissions will either remain the same or decrease from the baseline to the project scenario, see page 8 for further explanation |

| SSR | GHG Source | Gas | Relevant to Baseline (B) or Project (P) | Included/ Excluded | Justification/Explanation |
|---|---|---|---|---|---|
| 9 | Emissions from combustion during flaring, including emissions from incomplete combustion of biogas | $CO_2$ | P | *Excluded* | Biogenic emissions are excluded. |
| | | $CH_4$ | | *Included* | Primary source of emissions from project activities. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 10 | Emissions from combustion during electric generation, including incomplete combustion of biogas | $CO_2$ | P | *Excluded* | Biogenic emissions are excluded. |
| | | $CH_4$ | | *Included* | Primary source of emissions from project activities. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 11 | Emissions from upgrading biogas for pipeline injection or use as CNG/LNG fuel | $CO_2$ | P | *Included* | Emissions resulting from on-site fossil fuel use and/or grid electricity may be significant. |
| | | $CH_4$ | | *Excluded* | Emission source is assumed to be very small. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 12 | Emissions from combustion at boiler, including emissions from incomplete combustion of biogas | $CO_2$ | P | *Excluded* | Biogenic emissions are excluded. |
| | | $CH_4$ | | *Included* | Primary source of emissions from project activities. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 13 | Emissions from combustion of biogas by end user of pipeline or CNG/LNG, including incomplete combustion | $CO_2$ | P | *Excluded* | Biogenic emissions are excluded. |
| | | $CH_4$ | | *Included* | Primary source of emissions from project activities. |
| | | $N_2O$ | | *Excluded* | Emission source is assumed to be very small. |
| 14 | Use of project-generated electricity | $CO_2$<br>$CH_4$<br>$N_2O$ | P | *Excluded* | This protocol does not cover displacement of GHG emissions from the use of biogas-generated electricity. |
| 15 | Off-site use of project-generated thermal energy or power | $CO_2$<br>$CH_4$<br>$N_2O$ | P | *Excluded* | This protocol does not cover displacement of GHG emissions from the use of biogas delivered through pipeline or other end uses. |
| 16 | Use of project-generated thermal energy | $CO_2$<br>$CH_4$<br>$N_2O$ | P | *Excluded* | This protocol does not cover displacement of GHG emissions from the use of biogas-generated thermal energy. |
| | Project construction and decommissioning emissions | $CO_2$<br>$CH_4$<br>$N_2O$ | P | *Excluded* | Emission source is assumed to be very small. |

# 5 Quantifying GHG Emission Reductions

GHG emission reductions from a livestock project are quantified by comparing actual project emissions to baseline emissions at the project site. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the livestock project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary during the reporting period. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

GHG emission reductions are generally quantified and verified on an annual basis. Project developers may choose to verify GHG emission reductions on a more frequent or less frequent basis if they desire (see Section 7.3). The length of time over which GHG emission reductions are quantified and reported to the Reserve is called the "reporting period." The length of time over which GHG reductions are verified is called a "verification period." Under this protocol, a verification period may cover multiple reporting periods (see Section 7.3.4). Project developers should take note that some equations to calculate baseline and project emissions are run on a month-by-month basis and activity data monitoring takes place at varying levels of frequency. As applicable, monthly emissions data (for baseline and project) are summed together to calculate emission reductions over a given reporting period. Projects whose reporting periods begin or end with incomplete calendar months shall only quantify the baseline and project emissions for the portion of the month that is included within the reporting period.
The calculations provided in this protocol are derived from internationally accepted methodologies.[8] Project developers shall use the calculation methods provided in this protocol to determine baseline and project GHG emissions in order to quantify GHG emission reductions.

To support project developers and facilitate consistent and complete emissions reporting, the Reserve has developed an Excel-based calculation tool. This tool is available to all Reserve account holders and their designated representatives. Instructions for obtaining the most recent version of this tool are available on the U.S. Livestock Project Protocol webpage. The Reserve *recommends* the use of the Livestock Calculation Tool for all project calculations and emission reduction reports. Only the most recent version of this tool should be used, unless otherwise recommended by Reserve staff. In any case where there is potential disagreement between guidance provided in the protocol and guidance provided in the calculation tool, the protocol shall take precedence.

The current methodology for quantifying the GHG impact associated with installing a BCS requires the use of both modeled reductions (following Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9) as well as the utilization of *ex-post* metered data from the BCS to be used as a check on the modeled reductions.

The Reserve recognizes that there can be material differences between modeled methane emission reductions and the actual metered quantity of methane that is captured and destroyed by the BCS due to digester start-up periods, venting events, and other BCS operational issues.

[8] The Reserve's GHG reduction calculation method is derived from the Kyoto Protocol's Clean Development Mechanism (ACM0010 V.5), the EPA's Climate Leaders Program (Manure Offset Protocol, August 2008), and the RGGI Model Rule (January 5, 2007).

These operational issues have the potential to result in substantially less methane destruction than is modeled, leading to an overestimation of GHG reductions in the modeled case.

To address this issue and maintain consistency with international best practice, the Reserve requires the modeled methane emission reduction results to be compared to the *ex-post* metered quantity of methane that is captured and destroyed by the BCS. The lesser of the two values will represent the total methane emission reductions for the reporting period. Equation 5.1 below outlines the quantification approach for calculating the emission reductions from the installation of a BCS.

## 5.1 Required Parameters for Modeling Baseline and Project Emissions

The following parameters must be determined for the modeling of baseline and project emissions:

**Population – $P_L$**

The procedure requires project developers to differentiate between livestock categories (*L*) (e.g. lactating dairy cows, non-milking dairy cows, heifers, etc.). This accounts for differences in methane generation across livestock categories. See Appendix B, Table B.2 for methane generation values. The population of each livestock category shall be monitored on a monthly basis, and for Equation 5.4 is averaged for an annual total population.

**Volatile solids – $VS_L$**

This value represents the daily organic material in the manure for each livestock category and consists of both biodegradable and non-biodegradable fractions. The VS content of manure is a combination of excreted fecal material (the fraction of a livestock category's diet consumed and not digested) and urinary excretions, expressed in a dry matter weight basis (kg/animal).[9] This protocol requires that the VS value for all livestock categories be determined as outlined in Box 5.1.

**$Mass_L$**

This value is the annual average live weight of the animals, per livestock category. These data are necessary because default VS values are supplied in units of kg/day/1000kg mass, therefore the average mass of the corresponding livestock category is required in order to convert the units of VS into kg/day/animal. Site specific livestock mass is preferred for all livestock categories. If site-specific data are unavailable, Typical Animal Mass (TAM) values may be used (see Appendix B, Table B.2).

**Maximum methane production – $B_{0,L}$**

This value represents the maximum methane-producing capacity of the manure, differentiated by livestock category (*L*) and diet. Project developers shall use the default $B_0$ factors from Appendix B, Table B.3. Alternatively, project developers may follow the sampling and testing procedure contained in Section 6.1 in order to determine a site-specific $B_0$ value for a particular animal category.

[9] IPCC 2006 Guidelines volume 4, chapter 10, p. 10.42.

**$MS_S$**

The MS value apportions manure from each livestock category to appropriate manure management system component (*S*), and is a critical factor in determining a project baseline, as well as project emissions from effluent treatment. It reflects the reality that waste from the operation's livestock categories are not managed uniformly. The MS value accounts for the operation's multiple types of manure management systems. It is expressed as a percent (%), relative to the total amount of VS produced by the livestock category. As waste production is normalized for each livestock category, the percentage shall be calculated as percent of population for each livestock category. For example, a dairy operation might send 85% of its milking cows' waste to an anaerobic lagoon and 15% could be deposited in a corral. In this situation, an MS value of 85% would be assigned to Equation 5.3 and 15% to Equation 5.4.

Importantly, the MS value indicates where the waste would have been managed in the baseline scenario. If a portion of the VS was removed from the waste stream through some sort of separation procedure, the MS value shall be adjusted to accurately reflect the baseline treatment of the VS. To account for VS removal from solids separation equipment, project developers may use a default value for the particular type of separation mechanisms employed (Table B.9), or a site-specific value based on the removal efficiency of the baseline system.

$MS_{BCS}$, which represents the fraction of manure that is sent to the BCS in the project scenario, follows the same logic as above, but is used to accurately quantify the project methane emissions from effluent treatment (see Equation 5.8).

**$MGS_{BCS}$**

The $MGS_{BCS}$ value represents the maximum biogas storage capacity of the BCS system. This value is needed only in the case of a venting event during the reporting period, which is quantified using Equation 5.7. If the BCS consists of multiple digester tanks or covered lagoons, the project only need quantify the maximum storage ($MGS_{BCS}$) and biogas flow ($F_{pw}$) of the component(s) of the BCS that experienced the venting event.

### Methane conversion factor – MCF

This method to calculate methane emissions reflects the site-specific monthly biological performance of the operation's baseline anaerobic manure management systems, as predicted using the van't Hoff-Arrhenius equation and farm-level data on temperature, as well as VS loading and system VS retention time.[10]

Each manure management system component has a volatile solids-to-methane conversion efficiency that represents the degree to which maximum methane production ($B_0$) is achieved. Methane production is a function of the extent of anaerobic conditions present in the system, the temperature of the system, and the retention time of organic material in the system.[11]

Default MCF values for non-anaerobic baseline manure management system components (as well as certain project BCS effluent treatment and Non-BCS sources) are available in Appendix B. These are used in Equation 5.4 and Equation 5.9.

Contrastingly, site-specific calculations of volatile solids-to-methane conversion efficiency are required for anaerobic baseline manure management system components and for the anaerobic

[10] The method is derived from Mangino et al., "Development of a Methane Conversion Factor to Estimate Emissions from Animal Waste Lagoons" (2001).
[11] IPCC 2006 Guidelines volume 4, chapter 10, p. 10.43.

treatment of project BCS effluent. For anaerobic lagoons, storage ponds, liquid slurry tanks etc., project developers perform a site-specific calculation of the mass of volatile solids degraded by the anaerobic storage/treatment system. This is expressed as “degraded volatile solids” or $VS_{deg}$ in Equation 5.3, which equals the system’s monthly available volatile solids multiplied by ‘*f*’, the van’t Hoff-Arrhenius factor. The ‘*f*’ factor effectively converts total available volatile solids in the anaerobic manure storage/treatment system to methane-convertible volatile solids, based on the monthly temperature of the system. The multiplication of $VS_{deg}$ by $B_0$ quantifies the maximum potential methane emissions that would have been produced for each livestock category’s contribution of manure to that system.

**Equation 5.1** GHG Reductions from Installing a Biogas Control System

$$ER = \min\{ER_{modeled}, ER_{metered}\}$$

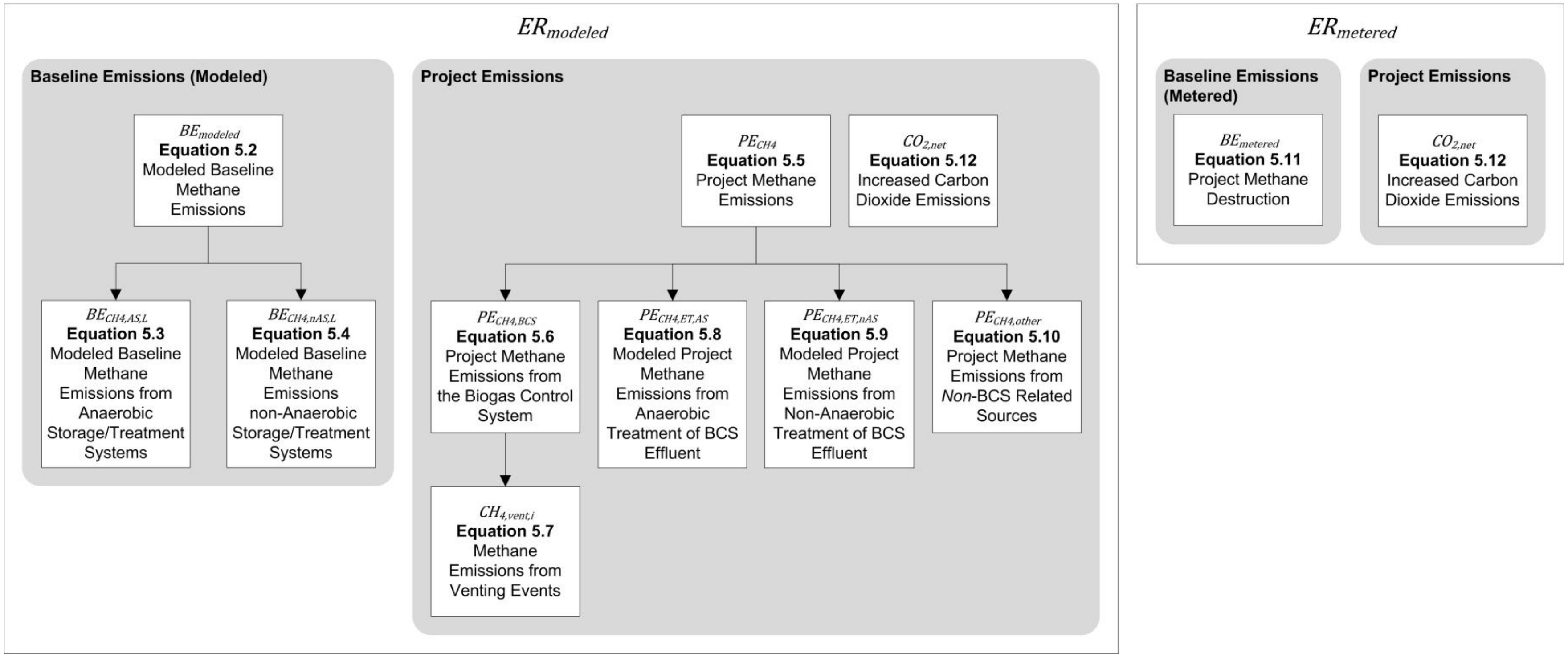



**Figure 5.1.** Organization of Equations in Section 5

**Equation 5.1.** GHG Reductions from Installing a Biogas Control System

$$ER = \min\{ER_{modeled}, ER_{metered}\}$$

$$ER_{modeled} = BE_{modeled} - PE_{CH_4} - CO_{2,net}$$

*Where,* Units

| | | | |
|---|---|---|---|
| $ER_{modeled}$ | = | Avoided methane emissions associated with the project during the reporting period, quantified using a modeled baseline scenario | $tCO_2e$ |
| $BE_{modeled}$ | = | Modeled baseline emissions from the baseline scenario (Equation 5.2) | $tCO_2e$ |
| $PE_{CH4}$ | = | Total project methane emissions during the reporting period (Equation 5.5) | $tCO_2e$ |
| $CO_{2,net}$ | = | Net increase in anthropogenic $CO_2$ emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity (Equation 5.12) | $tCO_2e$ |

$$ER_{metered} = BE_{metered} - CO_{2,net}$$

*Where,* Units

| | | | |
|---|---|---|---|
| $ER_{metered}$ | = | Avoided methane emissions associated with the project during the reporting period, quantified using metered methane destruction data | $tCO_2e$ |
| $BE_{metered}$ | = | Aggregated quantity of methane collected and destroyed during the reporting period (Equation 5.11) | $tCO_2e$ |
| $CO_{2,net}$ | = | Net increase in anthropogenic $CO_2$ emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity (Equation 5.12) | $tCO_2e$ |

## 5.2 Modeling Baseline Methane Emissions

Baseline emissions represent the GHG emissions within the GHG Assessment Boundary that would have occurred if not for the installation of the BCS. For the purposes of this protocol, project developers calculate their baseline emissions according to the manure management system in place prior to installing the BCS. Baseline emissions are then recalculated for each reporting period to reflect what the emissions would have been had the previous management system continued to function under current conditions. For Greenfield projects, as defined in Section 3.4.2, the baseline manure management practices shall be modeled according to the default values provided in Table B.10.

The procedure to determine the modeled baseline methane emissions follows Equation 5.2, which combines Equation 5.3 and Equation 5.4. The calculation procedures use a combination of site-specific values and default factors.

**Box 5.1.** Daily Volatile Solids for All Livestock Categories

Consistent with international best-practice, it is recommended that appropriate $VS_L$ values for dairy livestock categories be obtained from the state-specific lookup tables (Tables B.5.a – B.5.f) provided in Appendix B. When possible, use the year corresponding to the appropriate emission year. If the current year's table is not included in the protocol, use the most current year that is available from the Reserve. Updated tables will be provided in the Livestock Calculation Tool, as well as the Reserve website.[12]

$VS_L$ values for all other livestock can be found in Appendix B, Table B.3.

*Important* – Units provided for all VS values in Appendix B are in (kg/day/1000kg), In order to get $VS_L$ in the appropriate units (kg/animal/day), the following equation must be used:

$$\boldsymbol{VS_L = VS_{Table} \times \frac{Mass_L}{1000}}$$

*Where,* Units

| | | | Units |
|---|---|---|---|
| $VS_L$ | = | Volatile solid excretion on a dry matter weight basis | kg/animal/day |
| $VS_{Table}$ | = | Volatile solid excretion from lookup table (Table B.3 and Table B.5a - B.5d) | kg/day/1000kg |
| $Mass_L$ | = | Average live weight for livestock category *L*. If site specific data are unavailable, use values from Appendix B, Table B.2 corresponding to the appropriate emission year (or the most current year that is available from the Reserve) | kg |

**Equation 5.2.** Modeled Baseline Methane Emissions

$$\boldsymbol{BE_{modeled} = \sum_{S,L}\left(BE_{CH_4,AS,L} + BE_{CH_4,nAS,L}\right)}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $BE_{modeled}$ | = | Total baseline methane emissions during the reporting period, summed for each baseline treatment system *S* and livestock category *L* | $tCO_2e$ |
| $BE_{CH4,AS,L}$ | = | Total monthly baseline methane emissions from anaerobic storage/treatment system *AS* by livestock category *L*, aggregated for the reporting period. See Equation 5.3 | $tCO_2e$ |
| $BE_{CH4,nAS,L}$ | = | Total baseline methane emissions for the reporting period from non-anaerobic storage/treatment systems by livestock category *L.* See Equation 5.4 | $tCO_2e$ |

[12] http://www.climateactionreserve.org/how/protocols/us-livestock/

**Equation 5.3.** Modeled Baseline Methane Emissions from Anaerobic Storage/Treatment Systems

$$BE_{CH_4,AS,L} = \left(VS_{deg,AS,L} \times B_{0,L} \times days_{mo} \times 0.68 \times 0.001 \times 21\right) \times \left(\frac{rd_{mo}}{days_{mo}}\right)$$

*Where,* Units

| | | | |
|---|---|---|---|
| $BE_{CH4,AS,L}$ | = | Total monthly baseline methane emissions from anaerobic manure storage/treatment system *AS* from livestock category *L* | $tCO_2e/yr$ |
| $VS_{deg,AS,L}$ | = | Monthly volatile solids degraded in anaerobic manure storage/treatment system *AS* from livestock category *L* | kg dry matter |
| $B_{0,L}$ | = | Maximum methane producing capacity of manure for livestock category *L* – see Appendix B, Table B.3 for default values or Section 6.1 for guidance on determining a site-specific value | $m^3$ $CH_4$/kg of VS |
| 0.68 | = | Density of methane (1 atm, 60°F) | $kg/m^3$ |
| 0.001 | = | Conversion factor from kg to metric tons | |
| 21 | = | Global Warming Potential of methane as carbon dioxide equivalent | $tCO_2e/tCH_4$ |
| $days_{mo}$ | = | Calendar days per month | days |
| $rd_{mo}$ | = | Reporting days during the current month (see Box 5.2) | days |

$$VS_{deg,AS,L} = \sum_{AS,L}\left(VS_{avail,AS,L} \times f\right)$$

*Where,* Units

| | | | |
|---|---|---|---|
| $VS_{deg,AS,L}$ | = | Monthly volatile solids degraded by anaerobic manure storage/ treatment system *AS* by livestock category *L* | kg dry matter |
| $VS_{avail,AS,L}$ | = | Monthly volatile solids available for degradation from anaerobic manure storage/treatment system *AS* by livestock category *L* | kg dry matter |
| *f* | = | The van't Hoff-Arrhenius factor = "the proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system" [13] | |

**Equation 5.3 continued on next page.**

[13] Mangino, et al.

**Equation 5.3.** Continued

$$\boldsymbol{VS_{avail,AS,L} = \left(VS_L \times P_L \times MS_{AS,L} \times days_{mo} \times 0.8\right) + \left(VS_{avail-1,AS} - VS_{deg-1,AS}\right)}$$

| *Where,* | | | Units |
|---|---|---|---|
| $VS_{avail,AS,L}$ | = | Monthly volatile solids available for degradation in anaerobic storage/treatment system *AS* by livestock category *L* | kg dry matter |
| $VS_L$ | = | Volatile solids produced by livestock category *L* on a dry matter basis. Refer to Box 5.1 for guidance on using appropriate units for $VS_L$ values from Appendix B | kg/animal/day |
| $P_L$ | = | Average population of livestock category *L* (based on population data for the current month) | |
| $MS_{AS,L}$ | = | Percent of manure sent to (managed in) anaerobic manure storage/treatment system *AS* from livestock category *L* [14] | % |
| $days_{mo}$ | = | Calendar days per month | days |
| 0.8 | = | Management and design practices factor[15] | |
| $VS_{avail-1,AS}$ | = | Previous month's volatile solids available for degradation in anaerobic system *AS*[16] | kg |
| $VS_{deg-1,AS}$ | = | Previous month's volatile solids degraded by anaerobic system *AS* | kg |

$$\boldsymbol{f = exp\left[\frac{E\left(T_{mo} - T_{ref}\right)}{(R)\left(T_{ref}\right)\left(T_{mo}\right)}\right]}$$

| *Where,* | | | Units |
|---|---|---|---|
| *f* | = | The van't Hoff-Arrhenius factor | |
| E | = | Activation energy constant (15,175) | cal/mol |
| $T_{mo}$ | = | Monthly average ambient temperature (K = °C + 273). If $T_{mo}$ < 5°C then *f* = 0.104. If $T_{mo}$ > 29.5°C then *f* = 0.95 | Kelvin |
| $T_{ref}$ | = | 303.16; Reference temperature for calculation | Kelvin |
| R | = | Ideal gas constant (1.987) | cal/Kmol |

[14] The MS value represents the percent of manure that would be sent to (managed by) the anaerobic manure storage/treatment systems in the baseline case – as if the biogas control system was never installed.

[15] Mangino, et al. This factor was derived to "account for management and design practices that result in the loss of volatile solids from the management system." This reflects the difference between the theoretical modeled biological activity and empirical measurement of biological activity due to removal of liquid or other management practices that result in loss of VS from the treatment system. This does not account for removal of solids prior to the treatment system.

[16] IPCC 2006 Guidelines (Volume 4, Chapter 10, p. 42); ACM0010 (V2, p.8); and EPA Climate Leaders Manure Offset Protocol (August 2008).

**Box 5.2.** Calculating the Number of Reporting Days for a Reporting Period

For some projects, it may be necessary to exclude a number of days from the calculation of emission reductions. If the reporting period begins or ends mid-way through a month, the calculation shall be prorated to only include the number of days for each month that fall within the reporting period by setting *nrd* equal to the number of days that fall outside the reporting period. If the project is not eligible to report emission reductions for a certain period of time for other reasons (e.g. regulatory compliance issues, missing data), those days may also be included in the determination of *nrd*.

For example, if a reporting period begins on March 10, then $nrd_{March}$ = 9. If the same reporting period ends on December 31st of the same year, then $nrd_{rp}$ = 9, and *rd* = (306 – 9) = 297.

The following equation is used to determine the number of reporting days for the current period. This is to be applied for individual months for those equations that are run monthly, and for the entire reporting period for those equations that are run once per reporting period.

$$\boldsymbol{rd = days - nrd}$$

*Where,*

| | | |
|---|---|---|
| rd | = | Number of reporting days in the current period (month, reporting period, etc.) |
| days | = | Number of calendar days in the current period (e.g. equal to 30 for June) |
| nrd | = | Non-reporting days in the current period |

### Retention of Volatile Solids

Equation 5.3 calculates methane emissions from anaerobic manure storage/treatment systems based on site-specific information on the mass of volatile solids degraded by the anaerobic storage/treatment system and available for methane conversion.[17] It incorporates the effects of temperature through the van't Hoff-Arrhenius (*f*) factor and accounts for the retention of volatile solids through the use of monthly assumptions of baseline conditions. Each month, a certain quantity of VS is converted into methane ($VS_{deg}$). The VS that is available for conversion each month ($VS_{avail}$) is the sum of VS that enters the manure management system, as well as VS that remains in the system from the previous month ($VS_{avail-1} – VS_{deg-1}$).

Project developers shall not carry over volatile solids from one month to the next when modeling baseline anaerobic treatment systems where the retention time was 30 days or less. For these systems ($VS_{avail-1} – VS_{deg-1}$) = 0 in Equation 5.3 for every month.

Depending on the accumulation of sludge in the baseline manure storage system, it may have been necessary to drain and clean the system on a periodic basis. This cleaning removes the non-degraded VS that has accumulated in the system. For anaerobic lagoons with a retention time greater than 30 days, project developers shall zero out the VS retained in the system following the month when the system would have been completely drained and sludge removed under baseline operating conditions. For the month following the sludge removal, ($VS_{avail-1} – VS_{deg-1}$) = 0 in Equation 5.3. For projects where a BCS is being retrofit into existing operations, baseline anaerobic system management practices should reflect actual pre-project manure management practices on that farm.

[17] These system components must meet the Anaerobic Baseline requirement in Section 3.4.

If the farm utilized solids separation in the baseline (thus preventing or delaying sludge accumulation), this removal and alternative treatment of VS should be reflected in the MS values, as explained earlier in this section.

The removal of supernatant liquids for spraying on fields at agronomic rates does not affect the monthly carryover of VS, as long as the system maintains at least one meter of liquid depth. Projects therefore do not need to account for regular field spraying activities that meet this description.

Equation 5.4 applies to non-anaerobic storage/treatment systems. Both Equation 5.3 and Equation 5.4 reflect basic biological principles of methane production from available volatile solids, determine methane generation for each livestock category, and account for the extent to which the waste management system handles each category's manure.

**Equation 5.4.** Modeled Baseline Methane for Non-Anaerobic Storage/Treatment Systems

$$\boldsymbol{BE_{CH_4,nAS,L} = \left(P_L \times MS_{L,nAS} \times VS_L \times days_{rp} \times MCF_{nAS} \times B_{0,L}\right) \times 0.68 \times 0.001 \times 21 \times \left(\frac{rd_{rp}}{days_{rp}}\right)}$$

| *Where,* | | | Units |
|---|---|---|---|
| $BE_{CH4,nAS,L}$ | = | Total baseline methane emissions during the reporting period from non-anaerobic storage/treatment systems | $tCO_2e$ |
| $P_L$ | = | Average population of livestock category *L* during the reporting period (based on monthly population data) | |
| $MS_{L,nAS}$ | = | Percent of manure from livestock category *L* managed in non-anaerobic storage/treatment systems | % |
| $VS_L$ | = | Volatile solids produced by livestock category *L* on a dry matter basis. Refer to Box 5.1 for guidance on using appropriate units for $VS_L$ values from Appendix B | kg/animal/day |
| $days_{rp}$ | = | Number of days in the reporting period | days |
| $MCF_{nAS}$ | = | Methane conversion factor for non-anaerobic storage/treatment system. See Appendix B | % |
| $B_{0,L}$ | = | Maximum methane producing capacity for manure for livestock category *L*. See Appendix B, Table B.3 for default values, or Section 6.1 for determining a site-specific value | $m^3$ $CH_4$/kg of VS dry matter |
| 0.68 | = | Density of methane (1 atm, 60°F) | kg/$m^3$ |
| 0.001 | = | Conversion factor from kg to metric tons | |
| 21 | = | Global Warming Potential of methane as carbon dioxide equivalent | $tCO_2e/tCH_4$ |
| $rd_{rp}$ | = | Reporting days during the reporting period | days |

## 5.3 Calculating Project Methane Emissions

Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary after the installation of the BCS. Project emissions are calculated on an annual, *ex-post* basis. Like baseline emissions, some parameters are monitored on a monthly basis. Unlike baseline emission calculations, methane emissions from the BCS are calculated from metered data, rather than modeled projections. Methane emissions from manure storage and/or treatment systems other than the BCS are modeled much the same as in the baseline scenario.

As shown in Equation 5.5, project methane emissions equal:

- The amount of methane created by the BCS that is not captured and destroyed by the control system, plus
- Methane from the digester effluent treatment systems (where applicable), plus
- Methane from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems. This includes all other manure treatment systems such as compost piles, solids storage etc.

Consistent with this protocol's baseline methane calculation approach, the formula to account for project methane emissions incorporates all potential sources within the waste treatment and storage category. Non-BCS-related sources follow the same calculation approach as provided in the baseline methane equations. Several activity data for the variables in Equation 5.9 will be the same as those in Equation 5.2 to Equation 5.4.

If the project elects to install an impermeable cover on an effluent pond (potentially creating an additional anaerobic digester) and the biogas generated in this covered pond is collected and destroyed by the project BCS, then this covered pond shall be considered part of the project digester system. If the biogas generated by this covered pond is not destroyed, it must be quantified as project methane emissions using Equation 5.8.

Although not common under normal digester operation, it is possible that a venting event may occur due to catastrophic failure of digester cover materials, the digester vessel, or the gas collection system. In the event that a catastrophic system failure results in the venting of biogas, the quantity of methane released to the atmosphere shall be estimated according to Equation 5.7 below.

**Equation 5.5.** Project Methane Emissions

$$\boldsymbol{PE_{CH_4} = \left(PE_{CH_4,BCS} + PE_{CH_4,ET,AS} + PE_{CH_4,ET,nAS} + PE_{CH_4,other}\right) \times 21}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{CH4}$ | = | Total project methane emissions for the reporting period, | $tCO_2e$ |
| $PE_{CH4,BCS}$ | = | Methane emissions from the BCS during the reporting period (Equation 5.6) | $tCH_4$ |
| $PE_{CH4,ET,AS}$ | = | Monthly methane emissions from the BCS effluent anaerobic treatment systems, aggregated for the reporting period (Equation 5.8) | $tCH_4$ |
| $PE_{CH4,ET,nAS}$ | = | Methane emissions from the BCS effluent non-anaerobic treatment systems during the reporting period (Equation 5.9) | $tCH_4$ |
| $PE_{CH4,other}$ | = | Methane emissions from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems, during the reporting period (Equation 5.10) | $tCH_4$ |
| 21 | = | Global warming potential of methane as carbon dioxide equivalent | $tCO_2e/tCH_4$ |

**Equation 5.6.** Project Methane Emissions from the Biogas Control System

$$PE_{CH_4,BCS} = \sum_i \left[ \left[ CH_{4,metered,i} \times \left( \left( \frac{1}{BCE} \right) - BDE_{i,weighted} \right) \right] + CH_{4,vent,i} \right]$$

*Where,* Units

| | | | |
|---|---|---|---|
| $PE_{CH4,BCS}$ | = | Methane emissions from the BCS, to be summed for each reporting period | $tCH_4$ |
| $CH_{4,metered,i}$ | = | Quantity of methane collected and metered in month *i* | $tCH_4$ |
| BCE | = | Methane collection efficiency of the BCS. Project developers shall use the appropriate default value provided in Table B.4 | fraction |
| $BDE_{i,weighted}$ | = | Weighted average of all destruction devices used in month i | fraction |
| $CH_{4,vent,i}$ | = | Quantity of methane that is vented to the atmosphere due to BCS venting events in month *i*, as quantified in Equation 5.7 below | $tCH_4$ |

$$CH_{4,metered,i} = F \times \frac{520}{T_b} \times \frac{P}{1} \times CH_{4,conc} \times 0.0423 \times 0.000454$$

*Where,* Units

| | | | |
|---|---|---|---|
| $CH_{4,metered,i}$ | = | Wuantity of methane collected and metered in month *i*[18] | $tCH_4$ |
| F | = | Measured volumetric flow of biogas in month *i* | scf |
| $T_b$ | = | Temperature of the biogas flow (°R = °F + 459.67) | °R |
| P | = | Pressure of the biogas flow | atm |
| $CH_{4,conc}$ | = | Measured methane concentration of biogas for month *i* | fraction |
| 0.0423 | = | Density of methane gas (1 atm, 60°F) | lb $CH_4$/scf |
| 0.000454 | = | Conversion factor from lb to metric ton | |

** The terms (520/$T_b$) and (P/1) should be omitted if the continuous flow meter internally corrects for temperature and pressure to 60°F and 1 atm.*

$$BDE_{i,weighted} = \frac{\sum_{DD} \left( BDE_{DD} \times F_{i,DD} \right)}{F_i}$$

*Where,* Units

| | | | |
|---|---|---|---|
| $BDE_{i,weighted}$ | = | Monthly weighted average of all destruction devices used in month *i* | fraction |
| $BDE_{DD}$ | = | Default methane destruction efficiency of a particular destruction device 'DD'. See Appendix B for default destruction efficiencies[19] | fraction |
| $F_{i,DD}$ | = | Monthly flow of biogas to a particular destruction device 'DD' | scf/month |
| $F_i$ | = | Total monthly measured volumetric flow of biogas to all destruction devices | scf/month |

[18] This value reflects directly measured biogas mass flow and methane concentration in the biogas to the combustion device.

[19] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies, for each of the combustion devices used in the project. Site-specific values must be provided by an independent air emissions testing body that is accredited by a state or local agency, or the Stack Testing Accreditation Council (STAC). See Appendix B for more information. Where a state/region does not have an appropriate accreditation system or accredited service providers, the project developer may look to another state/region to find suitably qualified service providers.

**Equation 5.7.** Methane Emissions from Venting Events

$$CH_{4,vent,i} = \left(MGS_{BCS} + \left(F_{pw} \times t\right)\right) \times CH_{4,conc} \times 0.0423 \times 0.000454$$

*Where,*

| | | | Units |
|---|---|---|---|
| $CH_{4,vent,i}$ | = | Quantity of methane that is vented to the atmosphere due to BCS venting events in month *i* | $tCH_4$ |
| $MGS_{BCS}$ | = | Maximum biogas storage of the BCS system[20] | scf |
| $F_{pw}$ | = | Average total daily flow of biogas from the digester for the entire week prior to the venting event[20] | scf/day |
| t | = | Number of days of the month that biogas is venting uncontrolled from the BCS system (can be a fraction) | days |
| $CH_{4,conc}$ | = | Measured methane concentration of biogas prior to the venting event | fraction |
| 0.0423 | = | Density of methane gas (1 atm, 60°F) | lb $CH_4$/scf |
| 0.000454 | = | Conversion factor from lb to metric ton | |

Equation 5.8, along with Equation 5.9, shall be used to account for all treatment systems associated with the BCS effluent. The factor $ETF_i$ shall be estimated by the project developer to determine what fraction of the VS in the effluent is sent to each treatment system, and is represented as a fraction (e.g. if 85% of the BCS effluent is sent to an effluent pond, then $ETF_i$ for that system is equal to 0.85). Anaerobic effluent treatment systems are those which store liquid effluent in a lagoon, pond, or tank. This includes liquid storage systems that employ non-airtight covers (i.e. biogas is freely vented to the atmosphere) as long as the entire system is managed as a passive storage system, rather than an actively-managed treatment system (i.e. no heating, mixing, etc.).

**Equation 5.8.** Modeled Project Methane Emissions from Anaerobic Treatment of BCS Effluent

$$PE_{CH_4,ET,AS} = \sum_{i}\left(VS_{ET,i} \times B_{0,ET} \times days_{mo} \times 0.8 \times f \times 0.68 \times 0.001\right) \times \frac{rd_{mo}}{days_{mo}}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{CH4,ET,AS}$ | = | Monthly methane emissions from anaerobic effluent treatment systems | $tCH_4$ |
| $VS_{ET,i}$ | = | Volatile solids to anaerobic effluent treatment system *i* (see below) | kg/day |
| $B_{0,ET}$ | = | Maximum methane producing capacity (of VS dry matter)[21] | $m^3CH_4$/kg VS |
| $days_{mo}$ | = | Calendar days in the current month | days |
| 0.8 | = | Management and design practices factor[15] | fraction |
| *f* | = | The van't Hoff-Arrhenius factor, as calculated in Equation 5.3 | |
| 0.68 | = | Density of methane (1 atm, 60°F) | $kg/m^3$ |
| 0.001 | = | Conversion from kg to metric tons | t/kg |
| $rd_{mo}$ | = | Reporting days in the current month | days |

**Equation 5.8 continued on next page**

[20] If the BCS consists of multiple digester tanks or covered lagoons, the project only need quantify the maximum storage ($MGS_{BCS}$) and biogas flow ($F_{pw}$) of the component(s) of the BCS that experienced the venting event.
[21] The $B_0$ value for the project effluent pond is not differentiated by livestock category. Project developers shall use the $B_0$ value that corresponds with a weighted average of the operation's livestock categories that contribute manure to the BCS (weighted by the kg of VS contributed by each livestock category). Supporting laboratory data and documentation per Section 6.1 needs to be supplied to the verifier to justify an alternative value.

**Equation 5.8.** Continued

$$VS_{ET,i} = \left[\left(\sum_{L}(VS_L \times P_L \times MS_{L,BCS})\right) \times 0.3\right] \times ETF_i$$

*Where,*

| | | | Units |
|---|---|---|---|
| $VS_{ET,i}$ | = | Volatile solids to anaerobic effluent treatment system *i* | kg/day |
| $VS_L$ | = | Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for guidance on using appropriate units for $VS_L$ values from Appendix B | kg/animal/ day |
| $P_L$ | = | Average population of livestock category *L* during the reporting period (based on monthly population data) | |
| $MS_{L,BCS}$ | = | Fraction of manure from livestock category *L* that is managed in the BCS | fraction |
| 0.3 | = | Default value representing the amount of VS that exits the digester as a fraction of the VS entering the digester[22] | fraction |
| $ETF_i$ | = | Fraction of the effluent that exits the digester and is sent to effluent treatment system *i* | fraction |

If the effluent from the project digester is directed to a covered liquid effluent storage system, and the biogas from this storage system is not collected and destroyed, then the following scenarios apply:

1. If the effluent from this system is applied directly to land and biogas flow and methane concentration are monitored in accordance with Section 6, then $PE_{CH4,ET,AS}$ for this system shall be determined using Equation 5.6, assuming a BCE value of 0.95 and a BDE value of 0.

   For any periods where biogas flow and/or methane concentration data from this system are missing (and not replaceable through data substitution) or not in conformance with Section 6, Equation 5.8 shall be used to determine the quantity of project methane emissions from this system component.

2. If the effluent from the covered liquid effluent storage system is directed to another treatment system (i.e. not land-applied), then an additional calculation is required. The methane released from the covered liquid effluent system shall be quantified using the guidance in Scenario 1 above, but the additional methane released by the further treatment system must also be quantified. Equation 5.9 shall be used to calculate the methane released from the additional treatment system using the default assumptions that 30% of the $VS_{ET,i}$ from the effluent storage system enters the additional treatment system.

[22] Per ACM0010 (V2 Annex I).

**Equation 5.9.** Modeled Project Methane Emissions from Non-Anaerobic Treatment of BCS Effluent[23]

$$PE_{CH_4,ET,nAS} = \sum_i \left(VS_{ET,i} \times B_{0,ET} \times rd_{rp} \times 0.68 \times MCF_{ET,i} \times 0.001\right)$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{CH4,ET,nAS}$ | = | Project methane emissions from non-anaerobic effluent treatment systems during the reporting period | $tCH_4$ |
| $VS_{ET,i}$ | = | Volatile solids to non-anaerobic effluent treatment system *i* (see Equation 5.8) | kg/day |
| $B_{0,ET}$ | = | Maximum methane producing capacity (of VS dry matter)[24] | $m^3CH_4/kg$ |
| $rd_{rp}$ | = | Number of reporting days in the current reporting period | days |
| 0.68 | = | Density of methane (1 atm, 60°F) | $kg/m^3$ |
| $MCF_{ET,i}$ | = | Methane conversion factor for effluent treatment system *i* (Table B.6) | fraction |
| 0.001 | = | Conversion factor from kg to metric tons | |

**Equation 5.10.** Project Methane Emissions from *Non*-BCS Related Sources[25]

$$PE_{CH_4,other} = \sum_L \left(P_L \times VS_L \times B_{0,L} \times MCF_{non-BCS} \times rd_{rp} \times 0.68 \times 0.001\right)$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{CH4,other}$ | = | Methane from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems during the reporting period | $tCH_4$ |
| $P_L$ | = | Average population of livestock category *L* during the reporting period | |
| $VS_L$ | = | Volatile solids produced by livestock category 'L' on a dry matter basis. Refer to Box 5.1 for guidance on using appropriate units for $VS_L$ values from Appendix B | kg/ animal/ day |
| $B_{0,L}$ | = | Maximum methane producing capacity of VS dry matter for manure for livestock category *L*, (Appendix B, Table B.3) | $m^3$ $CH_4/kg$ |
| $MCF_{non\text{-}BCS}$ | = | Management-weighted methane conversion factor for waste treatment and storage systems other than the BCS and associated effluent treatment systems | fraction |
| $rd_{rp}$ | = | Number of reporting days in the current reporting period | days |
| 0.68 | = | Density of methane (1 atm, 60°F) | $kg/m^3$ |
| 0.001 | = | Conversion factor from kg to metric tons | |

$$MCF_{non-BCS} = \sum_S \left(MCF_S \times MS_{L,S}\right)$$

*Where,*

| | | | Units |
|---|---|---|---|
| $MCF_{non\text{-}BCS}$ | = | Management-weighted methane conversion factor for waste treatment and storage systems other than the BCS and associated effluent treatment systems | fraction |
| $MCF_S$ | = | Methane conversion factor for system component *S* (Table B.9) | fraction |
| $MS_{L,S}$ | = | Fraction of manure from livestock category *L* that is managed in non-BCS system component *S* | fraction |

[23] Non-anaerobic effluent treatment systems are those which manage effluent in solid form, or those which manage liquid effluent in a way that would be considered aerobic (e.g. a pond with effective aeration equipment).

[24] The $B_o$ value for the project effluent pond is not differentiated by livestock category. Project developers shall use the $B_o$ value that corresponds with a weighted average of the operation's livestock categories that contribute manure to the BCS (weighted by the kg of VS contributed by each livestock category). Supporting laboratory data and documentation per Section 6.1, need to be supplied to the verifier to justify an alternative value.

[25] According to this protocol, non-BCS-related sources means manure management system components (system component 'S') other than the biogas control system and the BCS effluent treatment systems (if used).

## 5.4 Metered Methane Destruction Comparison

As described above, the Reserve requires all projects to compare the modeled methane emission reductions for the reporting period, as calculated in Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9, with the actual metered amount of methane that is destroyed in the BCS over the same period. The lesser of the two values is to be used as the total methane emission reductions for the reporting period in question.

In order to calculate the metered methane reductions, the monthly quantity of biogas that is metered and destroyed by the BCS must be aggregated over the reporting period. In the event that a project developer is reporting reductions for a period of time that is less than a full year, the total modeled methane emission reductions would be aggregated over this time period and compared with the metered methane that is destroyed in the BCS over the same period of time. Similarly, projects whose reporting periods begin or end with incomplete calendar months shall only quantify the baseline and project emissions for the portion of the month that is included within the reporting period. For example, if a project is reporting and verifying only 6 months of data (e.g. July to December), then the modeled emission reductions over this 6 month period would be compared to the total metered biogas destroyed over the same six month period, and the lesser of the two values would be used as the total methane emission reduction quantity for this six month period. See Equation 5.1 for calculation guidance.

Equation 5.11 below details the metered methane destruction calculation.

**Equation 5.11.** Metered Methane Destruction

$$\boldsymbol{BE_{metered}} = \sum_{\boldsymbol{i}} \left(\boldsymbol{CH_{4,metered,i}} \times \boldsymbol{BDE_{i,weighted}}\right) \times \mathbf{21}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $BE_{metered}$ | = | Aggregated quantity of methane collected and destroyed during the reporting period | $tCO_2e$ |
| $CH_{4,metered,i}$ | = | Quantity of methane collected and metered in month $_i$. See Equation 5.6 for calculation guidance | $tCH_4$/month |
| $BDE_{i,weighted}$ | = | Weighted average of all destruction devices used in month *i*.[26] See Equation 5.6 for calculation guidance | fraction |
| 21 | = | Global warming potential of methane as carbon dioxide equivalent | $tCO_2e/tCH_4$ |

## 5.5 Calculating Baseline and Project Carbon Dioxide Emissions

Sources of carbon dioxide emissions associated with a project may include electricity use by pumps and equipment, fossil fuel generators used to power pumping systems or milking parlor equipment, tractors that operate in barns or free-stalls, on-site manure hauling trucks, or vehicles that transport manure off-site. Per Table 4.1, the carbon dioxide emissions from any additional equipment, vehicles, or fuel use that is required by the project beyond what is required in the baseline shall be accounted for. In practice, project developers shall account for the emissions from any new electric- or fuel-powered equipment or vehicles purchased and

[26] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies, for each of the combustion devices used in the project. Site-specific values must be provided by an independent air emissions testing body that is accredited by a state or local agency, or the Stack Testing Accreditation Council (STAC). See Appendix B for more information.

installed/operated specifically for the purpose of implementing the project, as well as any additional fuel used by old or new vehicles to collect or transport waste.

Project developers may either use Equation 5.12 below to calculate the net increase in carbon dioxide emissions, or, if they can demonstrate during verification that project carbon dioxide emissions are estimated to be equal to or less than 5% of the total baseline emissions, then the project developer may estimate baseline and project carbon dioxide emissions. If an estimation method is used, verifiers shall confirm based on professional judgment that project carbon dioxide emissions are equal to or less than 5% of the total baseline emissions based on documentation and the estimation methodology provided by the project developer. If emissions cannot be confirmed to be below 5%, then Equation 5.12 shall be used. Regardless of the method used, all estimates or calculations of anthropogenic carbon dioxide emissions within the GHG Assessment Boundary must be verified and included in emission reduction calculations.[27]

If calculations or estimates indicate that the project results in a net decrease in carbon dioxide emissions from grid-delivered electricity, mobile and stationary sources, then for quantification purposes the net increase in these emissions must be specified as zero (i.e. $CO_{2,net} = 0$ in Equation 5.12).

Carbon dioxide emissions from the combustion of biogas are considered biogenic emissions and are excluded from the GHG Assessment Boundary.

Equation 5.12 below calculates the net increase in anthropogenic carbon dioxide emissions resulting from the project activity.

[27] This is consistent with guidance in WRI's GHG Project Protocol regarding the treatment of significant secondary effects.

**Equation 5.12.** Increased Carbon Dioxide Emissions

$$CO_{2,net} = BE_{CO_2,MSC} - PE_{CO_2,MSC}$$

| Where, | | | Units |
|---|---|---|---|
| $CO_{2,net}$ | = | Net increase in anthropogenic $CO_2$ emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity during the reporting period. If result is <0, use a value of 0 | $tCO_2$ |
| $BE_{CO2,MSC}$ | = | Total baseline $CO_2$ emissions from electricity consumption and mobile and stationary combustion sources during the reporting period (see equation below) | $tCO_2$ |
| $PE_{CO2,MSC}$ | = | Total project $CO_2$ emissions from electricity consumption and mobile and stationary combustion sources during the reporting period (see equation below) | $tCO_2$ |

All $CO_2$ emissions associated with electricity consumption and stationary and mobile combustion are calculated using the equation:

$$CO_{2,MSC} = \left(\sum_c QE_c \times EF_{CO_2,e}\right) + \left[\left(\sum_c QF_c \times EF_{CO_2,f}\right) \times 0.001\right]$$

| Where, | | | Units |
|---|---|---|---|
| $CO_{2,MSC}$ | = | Anthropogenic $CO_2$ emissions from electricity consumption and mobile and stationary combustion sources | $tCO_2$ |
| $QE_c$ | = | Quantity of grid-connected electricity consumed for each emissions source 'c'[28] during the reporting period | MWh |
| $EF_{CO2,e}$ | = | $CO_2$ emission factor for electricity used[29] | $tCO_2$/MWh |
| $QF_c$ | = | Quantity of fuel consumed for each mobile and stationary emission source 'c' during the reporting period | MMBtu or gallons |
| $EF_{CO2,f}$ | = | Fuel-specific emission factor *f* from Appendix B | kg $CO_2$/MMBtu or kg $CO_2$/gallon |
| 0.001 | = | Conversion factor from kg to metric tons | |

[28] Emissions from electricity generated by the BCS and consumed onsite, do not need to be reported, as the resulting $CO_2$ emissions are considered biogenic, $CH_4$ is captured by the BDE calculation and $N_2O$ emissions are excluded as negligible.
[29] Refer to the version of the U.S. EPA eGRID most closely corresponding to the time period during which the electricity was used. Projects shall use the annual total output emission rates for the subregion where the project is located, not the annual non-baseload output emission rates. The eGRID tables are available from the U.S. EPA website: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html

# 6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan will serve as the basis for verification bodies to confirm that the monitoring and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 (below) will be collected and recorded.

At a minimum the Monitoring Plan shall stipulate the frequency of data acquisition; a record keeping plan (see Section 7.2 for minimum record keeping requirements); the frequency of instrument field check and calibration activities; and the role of individuals performing each specific monitoring activity, as well as QA/QC provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision. The Monitoring Plan shall also contain a detailed diagram of the BCS, including the placement of all meters and equipment that affect SSRs within the GHG Assessment Boundary (see Figure 4.1 and Appendix F).

For a project's second crediting period, the Monitoring Plan must also include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test (Section 3.5.2).

Project developers are responsible for monitoring the performance of the project and operating each component of the biogas collection and destruction system in a manner consistent with the manufacturer's recommendations.

## 6.1 Site-Specific Determination of Maximum Methane Potential ($B_0$)[30]

The determination of a site-specific value for maximum methane potential ($B_0$) is optional for manure from dairy facilities. Swine facilities must use the default values. For projects that choose this option for the quantification of emission reductions related to one or more manure streams being digested in the project's BCS, or the BCS effluent, the following criteria must be met in order to ensure accuracy and consistency of the site-specific $B_0$ values:

1. Manure samples for each eligible livestock category must be sampled prior to mixing with manure from other animal categories or any other waste streams. These samples shall be taken from the manure collection system, rather than from an individual animal.
    a. Scrape systems: Samples shall be collected from the freshly scraped manure.
    b. Flush systems: Samples shall be collected at the point that the flushed manure leaves the barn. Additional samples must be collected of the flush water prior to mixing with manure.
    c. BCS effluent: Samples shall be collected after the effluent has exited the digester and prior to any further treatment.

2. Sampling events shall occur during the time period between August and October, inclusive.
    a. Manure samples: For each eligible animal category, there shall be one single-day sampling event. A total of at least six samples of at least one half liter each must

[30] Background information on the development of this section can be found in Appendix E.

be taken during the event. Samples shall be taken one to three hours apart, and all samples of the same type shall be combined (i.e. dairy cow manure samples in one container). The composite sample shall be delivered to the testing laboratory as soon as possible following the collection of the final sample.[31]

b. Flush water samples: If the farm utilizes a flush system for manure collection, the flush water must be sampled prior to mixing with manure. Two samples of at least one liter shall be collected, one to three hours apart, during the manure sampling event. These samples shall be combined into one container and delivered to the testing laboratory as soon as possible.

c. Effluent samples: Two samples of at least one liter shall be collected, one to three hours apart, during the manure sampling event. These samples shall be combined into one container and delivered to the testing laboratory as soon as possible.[32]

3. All samples must be analyzed using a Biochemical Methane Potential (BMP) Assay procedure at an independent, third-party laboratory that is familiar and experienced with this test and ISO 11734.[33] The laboratory must be able to document at least three years of experience with the BMP assay, and must have procedures in place to maintain a consistent inoculum. The laboratory must maintain and follow a standard operating procedure that outlines the process used in undertaking BMP analysis at that laboratory, and which can be made available to the verifier upon request.

4. At least six test runs shall be conducted using material from the mixed manure sample (i.e. split the sample into two and test each in triplicate). Tests shall report the weight of VS for the sample (as kg of dry matter) as well as the volume of methane produced, in order to determine the maximum methane potential as $m^3$ $CH_4$/kg VS. If applicable, the flush water sample and effluent sample shall each be used for one test run in triplicate. The laboratory shall conduct an assay on the seed inoculum itself in order to control for its contribution to the methane potential of the manure samples. The laboratory shall also conduct a control assay with a substrate of known methane potential (such as glucose or cellulose) to verify correct procedures were followed and that the inoculum was viable. If the control assay differs from its established expected value by greater than 15%, all results from that batch of assays shall be discarded. Measurement of gas flow shall be corrected to standard temperature and pressure (60°F and 1 atm). Devices used to measure gas flow and methane content shall be properly installed and calibrated, such that they can provide results within +/- 5% accuracy.

5. After the manure sample has been analyzed, there should be at least six estimates for the methane potential. The site specific value for $B_0$ shall equal the 90% lower confidence limit of all assay results. For flush systems, the mean methane potential of the flush water results must be subtracted from the calculated methane potential of the flushed manure sample. For BCS effluent, the mean methane potential of the test results

[31] Note, while there is no prescribed timeline regarding how quickly samples must be delivered to a laboratory, the longer a sample is retained before testing, the lower the methane generating potential will be. This loss can be mitigated by storing and transporting samples at temperatures below 5°C.

[32] *Ibid*.

[33] For more information on BMP Assay analysis and procedures, see: Moody et al. "Use of Biochemical Methane Potential (BMP) Assays for Predicting and Enhancing Anaerobic Digester Performance." (2009) http://sa.pfos.hr/sa2009/radovi/pdf/Radovi/r10-009.pdf

shall be used for the quantification. Additional sampling and assays may be carried out, and will reduce uncertainty and result in a final value that is closer to the mean.

Site-specific $B_0$ values determined using this procedure shall be valid for the reporting period during which the sampling occurred. Projects may elect to determine a site-specific $B_0$ value for only a subset of the eligible manure streams and utilize default values for the remainder. The verifier must confirm that sampling procedures conform to this section and that the personnel responsible for the sampling are trained and competent.

## 6.2 Biogas Control System Monitoring Requirements

The methane capture and control system must be monitored with measurement equipment that directly meters:

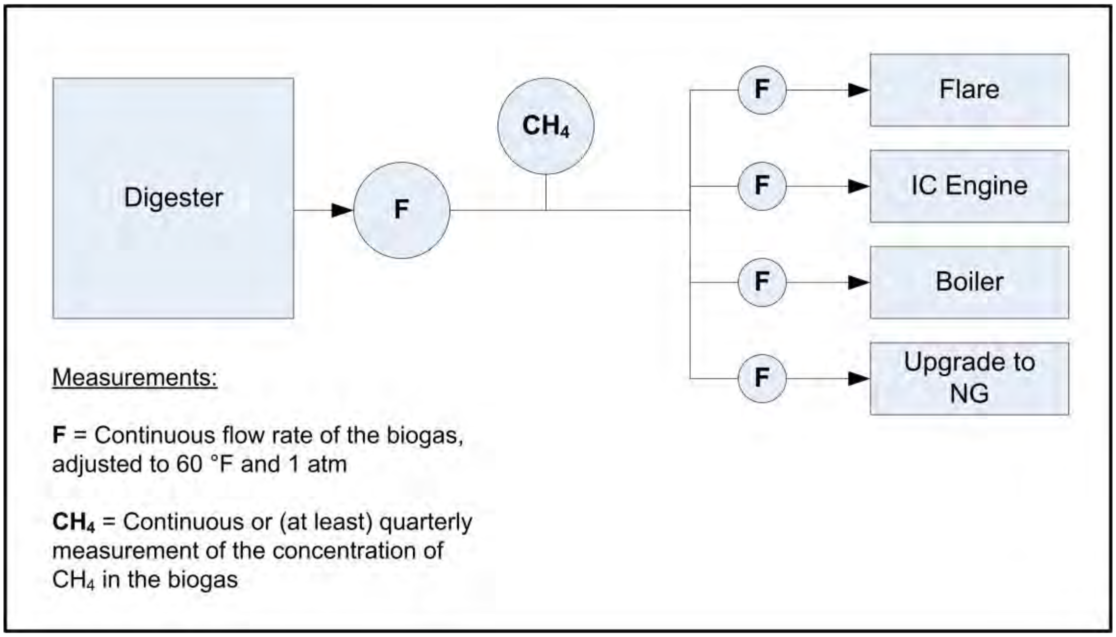
- The total flow of biogas, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure, prior to delivery to the destruction device(s).
- The flow of biogas delivered to each destruction device (except as described below), measured continuously and recorded at least every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure.
- The fraction of methane in the biogas, measured with a continuous analyzer or, alternatively, with at least quarterly measurements.
- The operational status of each destruction device (except as described below), measured and recorded at least hourly.

Flow data must be corrected for temperature and pressure at $60^{o}$F and 1 atm, either internally or by following the guidance in Equation 5.6.

A single flow meter may be used to monitor the flow of gas to multiple destruction devices under certain conditions. If all destruction devices are of identical methane destruction efficiency (as described in Table B.7) and verified to be operational (i.e. there is recorded evidence of destruction), no additional steps are necessary for project registration. One example of this scenario would be a single meter used for a bank of multiple, identical engines that are in constant operation. If the destruction devices are not of identical efficiency, then the destruction efficiency of the least efficient device shall be applied to the flow data for this meter.
If there are any periods where the operational data show that one or more devices were not destroying methane, these periods are eligible for crediting, provided that the verifier can confirm all of the following conditions are met:

a. The destruction efficiency of the least efficient destruction device in operation shall be used as the destruction efficiency for all destruction devices monitored by this meter; and
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 where one or more destruction device(s) within this arrangement is not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period. For devices other than flares, it must be shown that the output corresponds to the flow of gas.

Figure 6.1 represents the suggested arrangement of the biogas flow meters and methane concentration metering equipment.




Note: The number of flow meters must be sufficient to track the total flow as well as the flow to each combustion device. The above example includes one more flow meter than would be necessary to achieve this objective.

**Figure 6.1.** Suggested Arrangement of Biogas Metering Equipment

Operational activity of the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction.

If for any reason the destruction device or the operational monitoring equipment (for example, the thermocouple on the flare) is inoperable, then all metered biogas going to the particular device shall be assumed to be released to atmosphere during the period of inoperability. In other words, during the period of inoperability, the destruction efficiency of the device must be assumed to be zero. In Equation 5.10, the monthly destruction efficiency (BDE) value shall be adjusted accordingly. See Box 6.1 below for an example BDE adjustment.

**Box 6.1.** Example BDE Adjustment

As an example, consider a situation where the primary destruction device is an open flare with a BDE of 96%, and it is found to be inoperable for a period of 5 days of a 30 day month. Assume that the total flow of biogas to the flare for the month is 3,000,000 scf, and that the total flow recorded for the 5 day period of inoperability is 500,000 scf. In this case the monthly BDE would be adjusted as follows:

$$BDE = \frac{[(0.96 \times 2{,}500{,}000) + (0.0 \times 500{,}000)]}{3{,}000{,}000} = 80\%$$

## 6.3 Biogas Measurement Instrument QA/QC

All gas flow meters[34] and continuous methane analyzers must be:

- In calibration (accurate to +/- 5% of the true value being measured) at time of installation. Calibration accuracy can be demonstrated through either a recent field check (as installed) or calibration by the manufacturer or a certified calibration service.
- Maintained per manufacturer's guidance, as well as cleaned and inspected on a quarterly basis, with the activities performed and as found/as left condition of the equipment documented.
- Field checked for calibration accuracy by an appropriately trained individual or a third-party technician with the percent drift documented, using either a portable instrument (such as a pitot tube)[35] or manufacturer specified guidance, at the end of but no more than 60 days prior to or after the end date of the reporting period.[36]
- Calibrated by the manufacturer or a certified calibration service per manufacturer's guidance or every 5 years, whichever is more frequent. Meters shall be calibrated to the range of conditions expected on site (e.g. pipe diameter, flow rate, temperature, pressure, gas composition) and as found/as left condition of the equipment documented.

If a stationary meter that was in use for 60 days or more is removed and not reinstalled during a reporting period, that meter shall either be field-checked for calibration accuracy prior to removal or calibrated (with percent drift documented) by the manufacturer or a certified calibration service prior to quantification of emission reductions for that reporting period.

If the field check on a piece of equipment reveals accuracy outside of a +/- 5% threshold, calibration by the manufacturer or a certified service provider is required for that piece of equipment, with as found/as left condition of the equipment documented.

For the interval between the last successful field check and any calibration event confirming accuracy below the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful field check until such time as the meter is properly calibrated and re-installed.

- For calibrations that indicate the flow meter was outside the +/- 5% accuracy threshold, the project developer shall estimate total emission reductions using i) the metered values without correction, and ii) the metered values adjusted based on the greatest calibration drift recorded at the time of calibration. The lower of the two emission reduction estimates shall be reported as the scaled emission reduction estimate.

---

[34] Field checks and calibrations of flow meters shall assess the volumetric output of the flow meter in SCF at 1 atm pressure and 60°F temperature.

[35] It is recommended that a professional third party calibration service be hired to perform flow meter field checks if using pitot tubes or other portable instruments, as these types of devices require professional training in order to achieve accurate readings.

[36] Instead of performing field checks, the project developer may instead have equipment calibrated by the manufacturer or a certified calibration service per manufacturer's guidance, at the end of but no more than 60 days prior to or after the end date of the reporting period to meet this requirement.

For example, if a project conducts field checks quarterly during a year-long verification period, then only three months of data will be subject at any one time to the penalties above. However, if the project developer feels confident that the meter does not require field checks or calibration on a greater than annual basis, then failed events will accordingly require the penalty to be applied to the entire year's data. Further, frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

If a portable instrument is used (such as a handheld methane analyzer), the portable instrument shall be calibrated at least annually – or per the manufacturer's guidance, whichever is more frequent – by the manufacturer or at an ISO 17025 accredited laboratory. Portable methane analyzers shall be calibrated to a known reference gas prior to each use.

### 6.3.1 Missing Data

In situations where the flow rate or methane concentration monitoring equipment is missing data, the project developer shall apply the data substitution methodology provided in Appendix D. This methodology may also be used for periods where the project developer can show that the data are available but known to be corrupted (and where this corruption can be verified with reasonable assurance). If for any reason the monitoring equipment on any given destruction device is inoperable (for example, the thermocouple on the flare), then the destruction efficiency of that device must be assumed to be zero. For periods when it is not possible to use data substitution to fill data gaps, no emission reductions may be claimed. The methane flow volume for these days shall be zero, and the number of reporting days for that month shall be reduced to exclude the days of missing data (see Box 5.2).

During any period where the project is not claiming emission reduction credits and is not classifying the period as a venting event, the project developer must be able to demonstrate that project emissions were not greater than baseline emissions.

## 6.4 Monitoring Parameters

Provisions for monitoring other variables to calculate baseline and project emissions are provided in Table 6.1. The parameters are organized by general project factors then by the calculation methods.

**Table 6.1.** Project Monitoring Parameters

| Equation Reference | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| | Regulations | Project developer attestation to compliance with regulatory requirements relating to the manure digester project | All applicable regulations | n/a | Every verification period | Information used to demonstrate compliance with associated regulations and rules, e.g. criteria pollutant and effluent discharge limits. |
| | L | Type of livestock categories on the farm | Livestock categories | o | Monthly | See Appendix B, Table B.2. |
| Equation 5.1 | $ER_{modeled}$ | Avoided methane emissions associated with the project during the reporting period | $tCO_2e$ | c | Every reporting period | Quantified using a modeled baseline scenario. |
| Equation 5.1 | $BE_{modeled}$ | Modeled baseline emissions during the reporting period | $tCO_2e$ | c | Every reporting period | Quantified using a modeled baseline scenario. |
| Equation 5.1<br>Equation 5.5 | $PE_{CH4}$ | Total project methane emissions during the reporting period | $tCO_2e$ | c | Every reporting period | Quantified using a modeled project scenario and metered methane destruction data. |
| Equation 5.1<br>Equation 5.12 | $CO_{2,net}$ | Net increase in anthropogenic $CO_2$ emissions from electricity and mobile/stationary combustion | $tCO_2e$ | c | Every reporting period | |
| Equation 5.1 | $ER_{metered}$ | Avoided methane emissions associated with the project during the reporting period | $tCO_2e$ | c | Every reporting period | Quantified using metered methane destruction data. |
| Equation 5.1<br>Equation 5.11 | $BE_{metered}$ | Aggregated quantity of methane collected and destroyed during the reporting period | $tCO_2e$ | c | Every reporting period | Quantified using metered methane destruction data. |

| Equation Reference | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| Equation 5.2 | $BE_{CH4,AS,L}$ | Total baseline methane emissions from anaerobic storage/treatment systems by livestock category, aggregated for reporting period | $tCO_2e$ | c | Monthly | |
| Equation 5.2<br>Equation 5.4 | $BE_{CH4,nAS,L}$ | Total baseline methane emissions for the reporting period from non-anaerobic storage/treatment systems by livestock category | $tCO_2e$ | c | Every reporting period | |
| Equation 5.3 | $VS_{deg,AS,L}$ | Monthly volatile solids degraded in each anaerobic storage system *AS*, for each livestock category *L* | kg | c, o | Monthly | Calculated value from operating records. Recommend Reserve Livestock Calculation Tool for all calculations. |
| Equation 5.3<br>Equation 5.4<br>Equation 5.10 | $B_{0,L}$ | Maximum methane producing capacity for manure by livestock category | ($m^3$ $CH_4$/ kg VS) | r | Every reporting period | See Appendix B, Table B.3. |
| Equation 5.3<br>Equation 5.8 | $days_{mo}$ | Calendar days per month | days | r | Monthly | See Box 5.2. |
| Equation 5.3<br>Equation 5.8 | $rd_{mo}$ | Reporting days during the current month | days | o | Monthly | See Box 5.2. |
| Equation 5.3 | $VS_{avail,AS,L}$ | Monthly volatile solids available for degradation in each anaerobic storage system, for each livestock category | kg | c, o | Monthly | Calculated value from operating records. Recommend Reserve Livestock Calculation Tool for all calculations. |
| Equation 5.3<br>Equation 5.8 | $f$ | van't Hoff-Arrhenius factor | n/a | c | Monthly | The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system. Recommend Reserve Livestock Calculation Tool for all calculations. |
| Equation 5.3<br>Equation 5.4<br>Equation 5.8<br>Equation 5.10 | $VS_L$ | Daily volatile solid production for each livestock category | (kg/animal/ day) | r, c | Every reporting period | Appendix B, Table B.3 and Table B.5a-d; see Box 5.1 for guidance on converting units from (kg/day/1000kg) to (kg/animal/day). |

| Equation Reference | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| Equation 5.3<br>Equation 5.4<br>Equation 5.8<br>Equation 5.10 | $P_L$ | Average number of animals for each livestock category | population (# head) | o | Monthly | |
| Equation 5.3 | $MS_{AS,L}$ | Fraction of manure from each livestock category managed in the anaerobic waste handling system | % | o | Every reporting period | Reflects the percent of waste handled by the system components *S* pre-project. Each system component must have an MS value per livestock category. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 100%. See Appendix B, Table B.1. |
| Equation 5.3 | $VS_{avail-1,AS}$ | Previous month's volatile solids available for degradation in anaerobic system | kg | c | Monthly | |
| Equation 5.3 | $VS_{deg-1,AS}$ | Previous month's volatile solids degraded by anaerobic system | kg | c | Monthly | |
| Equation 5.3 | E | Activation energy constant | cal/mol | r | | 15,175 cal/mol |
| Equation 5.3 | $T_{mo}$ | Average monthly temperature at location of the operation | °C | m/o | Monthly | Used for van't Hoff calculation and for choosing appropriate MCF value. |
| Equation 5.3 | $T_{ref}$ | Reference temperature | K | r | | 303.16 Kelvins |
| Equation 5.3 | R | Ideal gas constant | cal/Kmol | r | | 1.987 cal/Kmol |
| Equation 5.4 | $MS_{L,nAS}$ | Fraction of manure from each livestock category *L* managed in the non-anaerobic waste handling system | % | o | Every reporting period | Reflects the percent of waste handled by the system components *S* pre-project. Each system component must have an MS value per livestock category. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 100%. See Appendix B, Table B.1. |
| Equation 5.4 | $days_{rp}$ | Number of days in the reporting period | days | o | Every reporting period | See Box 5.2. |
| Equation 5.4 | $MCF_{nAS}$ | Methane conversion factor for non-anaerobic storage/treatment system | % | r | Every reporting period | From Appendix B. Differentiate by livestock category. |

| Equation Reference | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| Equation 5.4<br>Equation 5.9<br>Equation 5.10 | $rd_{rp}$ | Reporting days during the reporting period | days | | Every reporting period | See Box 5.2. |
| Equation 5.5<br>Equation 5.6 | $PE_{CH4,BCS}$ | Methane emissions from the BCS | $tCH_4$ | m, c | Every reporting period | Calculated for each month and summed for the reporting period. |
| Equation 5.5<br>Equation 5.8 | $PE_{CH4,ET,AS}$ | Methane emissions from the BCS effluent anaerobic treatment systems | $tCH_4$ | m, c | Every reporting period | Calculated for each month and summed for the reporting period. |
| Equation 5.5<br>Equation 5.9 | $PE_{CH4,ET,nAS}$ | Methane emissions from the BCS effluent non-anaerobic treatment systems | $tCH_4$ | m, c | Every reporting period | Calculated for the reporting period. |
| Equation 5.5<br>Equation 5.10 | $PE_{CH4,other}$ | Methane emissions from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems | $tCH_4$ | m, c | Every reporting period | Calculated for the reporting period. |
| Equation 5.6<br>Equation 5.11 | $CH_{4,metered,i}$ | Metered amount of methane collected and destroyed by the BCS in month *i* | $tCH_4$ | m, c | Monthly calculation from continuous data | Calculated from biogas flow and methane fraction meter readings (See *F* and $CH_{4,conc}$ parameters below). |
| Equation 5.6 | BCE | Biogas capture efficiency of the anaerobic digester, accounts for fugitive emissions | fraction | r | Every reporting period | Use default value from Table B.4. |
| Equation 5.6<br>Equation 5.11 | $BDE_{i,weighted}$ | Methane destruction efficiency of destruction device(s) | fraction | r, c | Monthly | Actual efficiency of the system to destroy captured methane gas – accounts for different destruction devices. |
| Equation 5.6<br>Equation 5.7 | $CH_{4,vent,i}$ | Quantity of methane that is vented to the atmosphere due to BCS venting events | scf | c | Monthly | Calculated from average total flow of biogas from the digester and the number of days biogas is venting. |
| Equation 5.6 | F | Volume of biogas from digester to destruction devices | scf | m | Continuously, aggregated monthly | Measured continuously from flow meter and recorded every 15 minutes or totalized and recorded at least once daily. Data to be aggregated monthly. |

| Equation Reference | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| Equation 5.6 | $T_b$ | Temperature of the biogas | °R (Rankine) | m | Continuously, averaged monthly | Measured to normalize volume flow of biogas to STP. No separate monitoring of temperature is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet. |
| Equation 5.6 | P | Pressure of the biogas | atm | m | Continuously, averaged monthly | Measured to normalize volume flow of biogas to STP. No separate monitoring of pressure is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet. |
| Equation 5.6 Equation 5.7 | $CH_{4,conc}$ | Methane concentration of biogas | fraction | m | At least quarterly | Samples to be taken at least quarterly. See Section 6.2 for metering guidance. |
| Equation 5.6 | $BDE_{DD}$ | Default methane destruction efficiency of a particular destruction device | % | r | Monthly | See Appendix B for default destruction efficiencies by device. |
| Equation 5.6 | $F_{i,DD}$ | Flow of biogas to a particular destruction device | scf | m | Monthly | See Section 6.2 for metering guidance. |
| Equation 5.6 | $F_i$ | Total volumetric flow of biogas to all destruction devices | scf | m | Monthly | See Section 6.2 for metering guidance. |
| Equation 5.7 | $MGS_{BCS}$ | Maximum biogas storage of the BCS system | scf | r | Every reporting period | Obtained from digester system design plans. Necessary to quantify the release of methane to the atmosphere due to an uncontrolled venting event. |
| Equation 5.7 | $F_{pw}$ | Average total daily flow of biogas from the digester for the entire week prior to the uncontrolled venting event | scf/day | m | Weekly | Average flow of biogas can be determined from the daily records from the previous week. |
| Equation 5.7 | t | Number of days of the month that biogas is venting uncontrolled from the BCS system | days | m, o | Monthly | |

| Equation Reference | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| Equation 5.8<br>Equation 5.9 | $VS_{ET,i}$ | Volatile solids to effluent treatment system *i* | kg/day | r, c | Every reporting period | If project uses effluent pond, equals 30% of the average daily VS entering the digester. |
| Equation 5.8<br>Equation 5.9 | $B_{0,ET}$ | Maximum methane producing capacity of VS dry matter | ($m^3$ $CH_4$/ kg VS) | c | Every reporting period | An average of the $B_{0,EF}$ value of the operation's livestock categories that contributes manure to the BCS. |
| Equation 5.8 | $MS_{L,BCS}$ | Fraction of manure from each livestock category managed in the BCS | fraction | o | Every reporting period | Used to determine the total VS entering the digester. The fraction should be tracked in operational records. |
| Equation 5.8 | $ETF_i$ | Fraction of the effluent that exits the digester that is sent to effluent treatment system | | o, r | Every reporting period | Used to determine the amount of VS for each effluent treatment system. The percentage should be tracked in operational records, or the project developer may provide a technical reference to support this fraction. |
| Equation 5.9 | $MCF_{ET,i}$ | Methane conversion factor for effluent treatment system | % | r | Every reporting period | See Appendix B. Project developers should use the *liquid slurry* MCF value. |
| Equation 5.10 | $MCF_{non\text{-}BCS}$ | Management-weighted methane conversion factor for waste treatment and storage systems other than the BCS and associated effluent treatment systems | % | r | Every reporting period | Referenced from Appendix B. |
| Equation 5.10 | $MCF_S$ | Methane conversion factor for system component | | r | | See Table B.9. |
| Equation 5.10 | $MS_{L,S}$ | Manure from each livestock category managed in the baseline waste handling system | fraction | o | Every reporting period | Fraction of waste handled by the system component *S* pre-project. Each system component must have an MS value per livestock category. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 1. See Appendix B, Table B.1. |
| Equation 5.12 | $BE_{CO2,MSC}$ | Total baseline $CO_2$ emissions from electricity and mobile/stationary combustion during reporting period | $tCO_2$ | c | Every reporting period | |

| Equation Reference | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| Equation 5.12 | $PE_{CO2,MSC}$ | Total project $CO_2$ emissions from electricity and mobile/stationary combustion during reporting period | $tCO_2$ | c | Every reporting period | |
| Equation 5.12 | $CO_{2,MSC}$ | Anthropogenic $CO_2$ emissions from electricity and mobile/stationary combustion | $tCO_2$ | c | Every reporting period | |
| Equation 5.12 | $QE_c$ | Quantity of electricity consumed | MWh | o, c | Every reporting period | Electricity used by project for manure collection, transport, treatment/storage, and disposal. |
| Equation 5.12 | $EF_{CO2,e}$ | Emission factor for electricity used by project | $tCO_2$/MWh | r | Every reporting period | See Appendix B. If biogas produced from digester is used to generate electricity consumed, the EF is zero. |
| Equation 5.12 | $QF_c$ | Quantity of fuel used for mobile/stationary combustion sources | MMBtu or gallons | o, c | Every reporting period | Fuel used by project for manure collection, transport, treatment/storage, and disposal, and stationary combustion sources including supplemental fossil fuels used in combustion device. |
| Equation 5.12 | $EF_{CO2,f}$ | Fuel-specific emission factor for mobile/stationary combustion sources | kg $CO_2$/ MMBtu or kg $CO_2$/ gallon | r | Every reporting period | Refer to EPA eGRID for emission factors. If biogas produced from digester is used as an energy source, the EF is zero. |

# 7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure among project developers. Project developers must submit either a project monitoring report or a verified emission reduction report to the Reserve annually at minimum, depending on the verification option selected by the project developer.

## 7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register a livestock project:

- Project Submittal form
- Project diagram from Monitoring Plan – see Appendix F (not public)
- Completed Reserve Livestock Calculation Tool, if used (not public)
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form[37]
- Signed Attestation of Regulatory Compliance form
- Verification Report
- Verification Statement

Project developers must provide the following documentation each verification period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Project diagram from Monitoring Plan – see Appendix F (not public)
- Completed Reserve Livestock Calculation Tool, if used (not public)
- Signed Attestation of Title form
- Signed Attestation of Regulatory Compliance form
- Signed Attestation of Voluntary Implementation form (second crediting period only)

Unless otherwise specified, the above project documentation will be available to the public via the Reserve's online registry. Further disclosure and other documentation may be made available on a voluntary basis through the Reserve. Project forms can be found athttp://www.climateactionreserve.org/how/program/documents/. .

## 7.2 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

[37] A project developer only needs to attest that the project passes the Legal Requirement Test during its first verification period of a crediting period. Meeting the Legal Requirement Test is not required for the remainder of the first crediting period after initial verification.

**System Information:**

- All data inputs for the calculation of the baseline emissions and project emission reductions
- $CO_2$e annual tonnage calculations (including copies of the Reserve Livestock Calculation Tool, if used)
- Relevant sections of the BCS operating permits
- Executed Attestation of Title forms, Attestation of Regulatory Compliance forms, and Attestation of Voluntary Implementation form
- BCS information (installation dates, equipment list, etc.)
- Biogas flow meter information (model number, serial number, manufacturer's calibration procedures)
- Cleaning and inspection records for all biogas meters
- Field check results for all biogas meters
- Calibration results for all biogas meters
- Methane monitor information (model number, serial number, calibration procedures)
- Biogas flow data (for each flow meter)
- Biogas temperature and pressure readings (only if flow meter does not correct for temperature and pressure automatically)
- Methane concentration monitoring data
- Destruction device monitoring data (for each destruction device)
- Destruction device, methane monitor and biogas flow monitor information (model numbers, serial numbers, calibration procedures)
- Initial and annual verification records and results
- All maintenance records relevant to the BCS, monitoring equipment, and destruction devices

**If using a calibrated portable gas analyzer for $CH_4$ content measurement:**

- Date, time, and location of methane measurement
- Methane content of biogas (% by volume) for each measurement
- Methane measurement instrument type and serial number
- Date, time, and results of instrument calibration
- Corrective measures taken if instrument does not meet performance specifications

## 7.3 Reporting and Verification Cycle

To provide flexibility and help manage verification costs associated with livestock projects, there are three verification options to choose from after a project's initial verification and registration. Regardless of the option selected, project developers must report GHG reductions resulting from project activities during each reporting period. A "reporting period" is a period of time over which a project developer quantifies and reports GHG reductions to the Reserve. Under this protocol, the reporting period cannot exceed 12 months. A "verification period" is the period of time over which GHG reductions are verified. Under this protocol, a verification period may cover multiple reporting periods (see Section 7.3.4). The end date of any verification period must correspond to the end date of a reporting period.

A project developer may choose to utilize one option for the duration of a project's crediting period, or may choose different options at different points during a single crediting period. Regardless of the option selected, reporting periods must be contiguous; there may be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced.

### 7.3.1 Initial Reporting and Verification Period

While a reporting period cannot exceed 12 months, a project developer may register multiple reporting periods (i.e. more than 12 months of data) during a project's initial verification period. A project developer may also register a project's initial verification period as a zero-credit reporting period (see the Reserve Program Manual for more information on zero-credit reporting periods).

Once a project is registered and has had at least 3 months of emission reductions verified, the project developer may choose one of the verification options below.

### 7.3.2 Option 1: Twelve-Month Maximum Verification Period

Under this option, the verification period may not exceed 12 months. Verification with a site visit is required for CRT issuance. The project developer may choose to have a sub-annual verification period (e.g. quarterly or semi-annually).

### 7.3.3 Option 2: Twelve-Month Verification Period with Desktop Verification

Under this option, the verification period cannot exceed 12 months. However, CRTs may be issued upon successful completion of a desktop verification as long as: (1) site-visit verifications occur at two-year intervals; and (2) the verifier has confirmed that there have been no significant changes in data management systems, equipment, or personnel since the previous site visit. Desktop verifications must cover all other required verification activities.

In order to utilize this option, there are two additional requirements that must be satisfied:

1. Prior to a desktop verification commencing, the project developer must attest to the verifier that there have been no significant changes to the project's data management systems, project set up/equipment, or site personnel involved with the project since the last site-visit verification. For each verification period, the project developer must provide the following documentation for review by the verifier prior to the desktop verification commencing:
    a. A schematic of system equipment and configuration, detailing any changes since the previous site visit, and any other supporting documentation for system or operation changes
    b. A list of personnel performing key functions related to project activities (personnel who manage and perform monitoring, measurement, and instrument QA/QC activities for the project), and documentation of any personnel or roles or changes since the pervious site visit; this shall include documented handover of personnel changes, including personnel change dates
    c. The sections from the Monitoring Plan that summarize the data management systems and processes in place and a summary of any changes to the systems or processes since the previous site visit

2. Desktop verifications must be conducted by the same verification body that conducted the most recent site-visit verification.

For projects using this option, the initial verification in this cycle shall be a full verification, including a site visit, and shall cover a minimum of 3 months and maximum 12 months of project data. All subsequent verification periods under this option shall be 12-month verification periods. Projects that wish to upgrade to the latest protocol version from a previous version whilst simultaneously taking advantage of the desktop verification option shall be allowed to do so, provided:

i. The verification of the previous verification period (e.g. under Version 2.1, 2.2 or 3.0) was a full verification, including site visit, and covered a minimum of 3 months of project data, and
ii. The two additional requirements specified in Section 7.3.3 are satisfied.

Taking into consideration the Reserve's policy that a verification body may provide verification services to a project for a maximum of six consecutive years (see the Verification Program Manual, Section 2.6 for more information), Table 7.1 below details what the verification cycle might look under Option 2.

**Table 7.1.** Sample Verification Cycle under Option 2

| Reporting Period | Verification Activity | Verification Body (VB) |
|---|---|---|
| Year 1 *(initial verification)* | Site-visit verification | VB A |
| Year 2 | Desktop verification | VB A |
| Year 3 | Site-visit verification | VB A |
| Year 4 | Desktop verification | VB A |
| Year 5 | Site-visit verification | VB A |
| Year 6 | Desktop verification | VB A |
| Year 7 | Site-visit verification | VB B *(new verification body)* |
| Year 8 | Desktop verification | VB B |

### 7.3.4 Option 3: Twenty-Four Month Maximum Verification Period

Under this option, the verification period cannot exceed 24 months and the project's monitoring report must be submitted to the Reserve for the interim 12 month reporting period. The project monitoring report must be submitted for projects that choose Option 3 to meet the annual documentation requirement of the Reserve program. It is meant to provide the Reserve with information and documentation on a project's operations and performance, and adherence to the project's monitoring plan. It is submitted via the Reserve's online registry, but is not a publicly available document. A monitoring report template for livestock projects is available at http://www.climateactionreserve.org/how/program/documents/. The monitoring report shall be submitted within 30 days of the end of the interim reporting period. The only exception to this requirement is for projects that verify under Option 3 as part of a protocol upgrade, and fall within the specific timeline outlined below.

Project developers that wish to upgrade to Version 4.0 of this protocol and immediately utilize the 24-month verification period shall be allowed to do so, provided that the verification of the previous verification period (e.g. under Version 2.0, 2.1, 2.2, or 3.0) was a full verification, including a site visit, and covered a minimum of 3 months of project data.

All project developers utilizing the 24-month verification period must submit the monitoring report within 30 days of the end of the interim reporting period.

Under this option, CRTs may be issued upon successful completion of a site-visit verification for GHG reductions achieved over a maximum of 24 months. CRTs will not be issued based on the Reserve's review of project monitoring plans/reports. Project developers may choose to have a verification period shorter than 24 months.

Taking into consideration the Reserve's policy that a verification body may provide verification services to a project for a maximum of six consecutive years (see the Verification Program Manual, Section 2.6 for more information), Table 7.2 below details what the verification cycle might look under Option 3.

**Table 7.2.** Sample Verification Cycle under Option 3

| Reporting Period | Verification Activity | Verification Body (VB) |
|---|---|---|
| Year 1 *(initial verification)* | Site-visit verification | VB A |
| Year 2 | Project monitoring plan and report submitted to Reserve | n/a |
| Year 3 | Site-visit verification for years 2 & 3 | VB A |
| Year 4 | Project monitoring plan and report submitted to Reserve | n/a |
| Year 5 | Site-visit verification for years 4 & 5 | VB A |
| Year 6 | Project monitoring plan and report submitted to Reserve | n/a |
| Year 7 | Site-visit verification for years 6 & 7 | VB B *(new verification body)* |
| Year 8 | Project monitoring plan and report submitted to Reserve | n/a |

# 8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions associated with installing a biogas control system for manure management on dairy cattle and swine farms. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities specifically related to livestock manure management projects.

Verification bodies trained to verify livestock projects must be familiar with the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve U.S. Livestock Project Protocol

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only Reserve-approved verification bodies are eligible to verify livestock project reports. Verification bodies approved under other project protocol types are not permitted to verify livestock projects. Information about verification body accreditation and Reserve project verification training can be found on the Reserve website at http://www.climateactionreserve.org.

## 8.1 Standard of Verification

The Reserve's standard of verification for livestock projects is the U.S. Livestock Project Protocol (this document), the Reserve Program Manual, and the Verification Program Manual. To verify a livestock project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Sections 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

## 8.2 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Section 6 are collected and recorded.

## 8.3 Verifying Project Eligibility

Verification bodies must affirm a livestock project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for livestock projects. This table does not present all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

**Table 8.1.** Summary of Eligibility Criteria for a Livestock Project

| Eligibility Rule | Eligibility Criteria | Frequency of Rule Application |
|---|---|---|
| Start Date | Projects must be submitted for listing within 6 months of the project start date | Once during first verification |
| Location | United States, its territories, and U.S. tribal areas | Once during first verification |
| Performance Standard Test | Installation of a biogas control system that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations | Once during first verification |
| Anaerobic Baseline | Projects must demonstrate that the depth of the anaerobic lagoons or ponds prior to the project's implementation were sufficient to prevent algal oxygen production and create an oxygen-free bottom layer; which means at least 1 meter in liquid depth | Once during first verification |
| Legal Requirement Test | Signed Attestation of Voluntary Implementation form and additional documentation demonstrating that the project passes the Legal Requirement Test | Once during first verification for first crediting period; every verification for second crediting period |
| Regulatory Compliance | Signed Attestation of Regulatory Compliance form and disclosure of all non-compliance events to verifier, and monitoring; project must be in material compliance with all applicable laws | Every verification |

## 8.4 Core Verification Activities

The U.S. Livestock Project Protocol provides explicit requirements and guidance for quantifying the GHG reductions associated with installing a BCS to capture and destroy methane gas from livestock operations. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a livestock project, but verification bodies must also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emission sources, sinks, and reservoirs
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

**Identifying emission sources, sinks, and reservoirs**

The verification body reviews for completeness the SSRs identified for a project, such as energy use waste collection and transport, treatment and storage, and uncombusted methane from the biogas control system.

**Reviewing GHG management systems and estimation methodologies**

The verification body reviews and assesses the appropriateness of the methodologies and management systems that the livestock project operator uses to gather data and calculate baseline and project emissions. This includes the examination of assertions or assumptions regarding MS, the percentage of manure going to anaerobic treatment systems in the baseline, and the baseline lagoon cleaning frequency.

**Verifying emission reduction estimates**

The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

## 8.5 Verification Period

Per Section 7.3, this protocol provides project developers three verification options for a project after its initial verification and registration in order to provide flexibility and help manage verification costs associated with livestock projects. The different options require verification bodies to confirm additional requirements specific to this protocol, and in some instances, to utilize professional judgment on the appropriateness of the option selected.

### 8.5.1 Option 1: Twelve-Month Maximum Verification Period

Option 1 does not require verification bodies to confirm any additional requirements beyond what is specified in the protocol.

### 8.5.2 Option 2: Twelve-Month Verification Period with Desktop Verification

Option 2 requires verification bodies to review the documentation specified in Section 7.3.3 in order to determine if a desktop verification is appropriate. The verifier shall use his/her professional judgment to assess any changes that have occurred related to a project's data management systems, equipment, or personnel and determine whether a site visit should be required as part of verification activities in order to provide a reasonable level of assurance on the project's verification. The documentation shall be reviewed prior to the COI/NOVA renewal being submitted to the Reserve, and the verification body shall provide a summary of its assessment and decision on the appropriateness of a desktop verification when submitting the COI/NOVA renewal. The Reserve reserves the right to review the documentation provided by the project developer and the decision made by the verification body on whether a desktop verification is appropriate.

### 8.5.3 Option 3: Twenty-Four Month Maximum Verification Period

Under Option 3 (see Section 7.3.4), verification bodies shall look to the project monitoring report submitted by the project developer to the Reserve for the interim 12 month reporting period as a resource to inform its planned verification activities. While verification bodies are not expected to provide a reasonable level of assurance on the accuracy of the monitoring report as part of verification, the verification body shall list a summary of discrepancies between the monitoring report and what was ultimately verified in the List of Findings.

## 8.6 Livestock Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a livestock project. The tables include references to the section in the protocol where requirements are further specified. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

***Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to livestock projects that must be addressed during verification.***

### 8.6.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for livestock projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or sub-set of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

**Table 8.2.** Eligibility Verification Items

| Protocol Section | Eligibility Qualification Item | Apply Professional Judgment? |
|---|---|---|
| 2.1 | Verify that the project meets the definition of a livestock project | No |
| 2.2 | Verify ownership of the reductions by reviewing Attestation of Title and other relevant contracts, documentation | No |
| 3.2 | Verify eligibility of project start date | No |
| 3.2 | Verify accuracy of project start date based on operational records | Yes |
| 3.3 | Verify that project is within its 10-year crediting period | No |
| 3.4 | Verify that all pre-project manure treatment lagoons/ponds/tanks were of sufficient depth to ensure an oxygen free bottom layer (> 1m) | Yes |
| 3.4 | Verify that the pre-project manure management system met the requirements of this section for the relevant period of time | Yes |
| 3.4 | If the project is a greenfield project, verify that the project site meets the definition of a greenfield | Yes |
| 3.5.1 | Verify that the project meets the Performance Standard Test | No |
| 3.5.2 | Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the Legal Requirement Test (initial verification only) | No |
| 3.6 | Verify that the project activities comply with applicable laws by reviewing instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form | Yes |
| 6 | Verify that monitoring meets the requirements of the protocol. If it does not, verify that variance has been approved for monitoring variations | No |
| 6 | Verify that all gas flow meters and continuous methane analyzers adhered to the inspection, cleaning, and calibration schedule specified in the protocol. If they do not, verify that a variance has been approved for | No |

| Protocol Section | Eligibility Qualification Item | Apply Professional Judgment? |
|---|---|---|
| | monitoring variations or that adjustments have been made to data per the protocol requirements | |
| 6 | Verify that adjustments for failed calibrations were properly applied | No |
| 6, Appendix D | If used, verify that data substitution methodology was properly applied | No |

### 8.6.2 Quantification

Table 8.3 lists the items that verification bodies shall include in their risk assessment and re-calculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

**Table 8.3.** Quantification Verification Items

| Protocol Section | Quantification Item | Apply Professional Judgment? |
|---|---|---|
| 4 | Verify that all SSRs in the GHG Assessment Boundary are accounted for | No |
| 5 | Verify that the modeled baseline is compared with the total amount of methane metered and destroyed by the project, and the lesser of the two values is used as the baseline for the GHG reduction calculation | No |
| 5.1 | Verify that the livestock categories (L) are correctly differentiated | Yes |
| 5.1 | Verify that the project developer applied the correct VS and $B_0$ values for each livestock category | No |
| 5.1, 6.1 | If site-specific $B_0$ values were developed, verify that the sampling and analysis procedures were correctly followed | Yes |
| 5.1 | Verify that the fraction of manure (MS) handled by the different manure management system components (i.e. GHG source) is satisfactorily represented | Yes |
| 5.1 | Verify that the baseline lagoon cleaning frequency is satisfactorily represented | Yes |
| 5.1 | Verify that the project developer used methane conversion factors (MCF) differentiated by temperature | No |
| 5.1 | Verify that the methane baseline emissions calculations for each livestock category were calculated according to the protocol with the appropriate data | No |
| 5.1 | Verify that the project developer correctly aggregated methane emissions from sources within each livestock category | Yes |
| 5.4 | Verify that the project developer correctly monitored, quantified and aggregated electricity use | Yes |
| 5.2, 5.4 | Verify that the project developer correctly monitored, quantified and aggregated fossil fuel use | Yes |
| 5.2, 5.4 | Verify that the project developer applied the correct emission factors for fossil fuel combustion and grid-delivered electricity | No |
| 5.2 | Verify that the project developer applied the correct methane destruction efficiencies | No |
| 5.2 | Verify that the project developer applied the correct $B_0$ value for Modeled Project Methane Emissions from Anaerobic Treatment of BCS Effluent | No |
| 5.2 | Verify that the project developer correctly quantified the amount of uncombusted methane | No |

| Protocol Section | Quantification Item | Apply Professional Judgment? |
|---|---|---|
| 5.2 | Verify that methane emissions resulting from any venting event are estimated correctly | Yes |
| 5.2, 5.4 | Verify that the project emissions calculations were calculated according to the protocol with the appropriate data | No |
| 5.2, 5.1 | Verify that the project developer assessed baseline and project emissions on a month-to-month basis | No |
| 5.2 | Verify that the project developer correctly monitored and quantified the amount of methane destroyed by the project | No |
| 5.3 | Verify that the modeled methane emission reductions are compared with the *ex-post* methane metered and destroyed by the project, and the lesser of the two values is used to quantify project emission reductions | No |

### 8.6.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

**Table 8.4.** Risk Assessment Verification Items

| Protocol Section | Item that Informs Risk Assessment | Apply Professional Judgment? |
|---|---|---|
| 6 | Verify that the project Monitoring Plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project | Yes |
| 6 | Verify that the BCS was operated and maintained according to manufacturer specifications | No |
| 6 | Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol | No |
| 6 | Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function | Yes |
| 6 | Verify that appropriate training was provided to personnel assigned to greenhouse gas reporting duties | Yes |
| 6 | Verify that all contractors are qualified for managing and reporting greenhouse gas emissions if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor's work | Yes |
| 7.2 | Verify that all required records have been retained by the project developer | No |

## 8.7 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project's verified status.

# 9 Glossary of Terms

| | |
|---|---|
| Accredited verifier | A verification firm approved by the Reserve to provide verification services for project developers. |
| Additionality | Manure management practices that are above and beyond business-as-usual operation, exceed the baseline characterization, and are not mandated by regulation. |
| Anaerobic | Pertaining to or caused by the absence of oxygen. |
| Anthropogenic emissions | GHG emissions resultant from human activity that are considered to be an unnatural component of the Carbon Cycle (i.e. fossil fuel combustion, deforestation etc.). |
| Biogas | The mixture of gas (largely methane) produced as a result of the anaerobic decomposition of livestock manure. |
| Biogas control system (BCS) | A system designed to capture and destroy the biogas that is produced by the anaerobic treatment and/or storage of livestock manure and/or other organic material. Commonly referred to as a “digester.” |
| Biogenic $CO_2$ emissions | $CO_2$ emissions resulting from the combustion and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the carbon cycle, as opposed to anthropogenic emissions. |
| Carbon dioxide ($CO_2$) | The most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms. |
| $CO_2$ equivalent ($CO_2e$) | The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs. |
| Direct emissions | Greenhouse gas emissions from sources that are owned or controlled by the reporting entity. |
| Emission factor | A unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g. metric tons of carbon dioxide emitted per barrel of fossil fuel burned). |
| Flare | A destruction device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. |
| Fossil fuel | A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals. |
| Greenfield | For the purposes of this protocol, a livestock facility that has been in operation for less than two years at a site that had no prior manure management infrastructure. |
| Greenhouse gas | Carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), |

| | |
|---|---|
| (GHG) | sulfur hexafluoride ($SF_6$), hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs). |
| Global warming potential (GWP) | The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of $CO_2$. |
| Indirect emissions | Emissions that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity. |
| Livestock project | Installation of a biogas control system that, in operation, causes a decrease in GHG emissions from the baseline scenario through destruction of the methane component of biogas. |
| Metric ton (tonne, MT, t) | A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons. |
| Methane ($CH_4$) | A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms. |
| MMBtu | One million British thermal units. |
| Mobile combustion | Emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g. cars, trucks, tractors, dozers, etc.). |
| Nitrous oxide ($N_2O$) | A GHG consisting of two nitrogen atoms and a single oxygen atom. |
| Project baseline | A business-as-usual GHG emission assessment against which GHG emission reductions from a specific GHG reduction activity are measured. |
| Project developer | An entity that undertakes a project activity, as identified in the Livestock Project Protocol. A project developer may be an independent third party or the dairy/swine operating entity. |
| Reporting period | The period of time over which a project developer quantifies and reports GHG reductions to the Reserve. Under this protocol, the reporting period cannot exceed 12 months. |
| Stationary combustion source | A stationary source of emissions from the production of electricity, heat, or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment. |
| van't Hoff-Arrhenius factor (*f*) | The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system.[38] |

[38] Mangino, et al.

| | |
|---|---|
| Verification | The process used to ensure that a given participant's greenhouse gas emissions or emission reductions have met the minimum quality standard and complied with the Reserve's procedures and protocols for calculating and reporting GHG emissions and emission reductions. |
| Verification body | An accredited firm that is able to render a verification opinion and provide verification services for operators subject to reporting under this protocol. |
| Verification period | The period of time over which GHG reductions are verified. Under this protocol, a verification period may cover multiple reporting periods (see Section 7.3.4). The end date of any verification period must correspond to the end date of a reporting period. |

# 10 References

American Society of Agricultural Engineers, Standard: ASAE D384.2 (2005).

Intergovernmental Panel on Climate Change, Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2001).

Intergovernmental Panel on Climate Change, IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 10: Emissions from Livestock and Manure Management (2006).

Intergovernmental Panel on Climate Change, IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 11: N20 Emissions from Managed Soils, and CO2 Emissions from Lime and Urea Application (2006).

Regional Greenhouse Gas Initiative, Draft Model Rule (January 2007).

Mangino, J., Bartram, D. and Brazy, A. Development of a methane conversion factor to estimate emissions from animal waste lagoons. Presented at U.S. EPA's 17th Annual Emission Inventory Conference, Atlanta GA, April 16-18, 2001.

Moser, M., Dr. J. Martin, A. Martin, R.P. Mattocks. Pig Manure Solids Separation. Unpublished report prepared by ICF Inc. for the Engineering Analysis Division, United States Environmental Protection Agency, Washington, DC. (1999).

Solid Waste Association of North America, Landfill gas operation and maintenance, manual of practice (1997).

Seebold, J.G., et al., Reaction Efficiency of Industrial Flares: The Perspective of the Past (2003).

United Nations Framework Convention on Climate Change (UNFCCC), Revisions to the Approved Consolidated Baseline Methodology ACM0010, “Consolidated baseline methodology for greenhouse gas emission reductions from manure management systems,” Clean Development Mechanism, Version 02, Sectoral Scopes 13 and 15 (2006).

U.S. Department, of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Anaerobic Digester—Ambient Temperature, No. 365.

U.S. Department of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Anaerobic Digester—Controlled Temperature, No. 366.

U.S. Department of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Waste Storage Facility, No. 313.

U.S. Department of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Waste Treatment Lagoon, No. 359.

U.S. Department of Energy 1605(b) Technical Guidelines for Voluntary Reporting of Greenhouse Gas Program.

U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002, 1990-2003, 1990-2004, 1990-2005, 1990-2006, and 1990-2007.

U.S. Environmental Protection Agency – Climate Leaders Draft Manure Offset Protocol (Managing Manure with Biogas Recovery Systems) (October 2006).

U.S. Environmental Protection Agency – Climate Leaders Offset Methodology for Managing Manure with Biogas Recovery Systems V.1.3 (2008).

Association of State Energy Research and Technology Transfer Institutions (ASERTTI), U.S. Environmental Protection Agency AgStar Program, and U.S. Department of Agriculture Rural Development, Protocol for Quantifying and Reporting the Performance of Anaerobic Digestion Systems for Livestock Manures (January 2007).

World Resource Institute and World Business Counsel for Sustainable Development, Greenhouse Gas Protocol for Project Accounting (November 2005).

# Appendix A Associated Environmental Impacts

Manure management projects have many documented environmental benefits, including air emission reductions, water quality protection, and electricity generation. These benefits are the result of practices and technologies that are well managed, well implemented, and well designed. However, in cases where practices or technologies are poorly or improperly designed, implemented, and/or managed, local air and water quality could be compromised.

With regard to air quality, there are a number of factors that must be considered and addressed to realize the environmental benefits of a biogas project and reduce or avoid potential negative impacts. Uncontrolled emissions from combustion of biogas may contain between 200 to 300 ppm NOx. The anaerobic treatment process creates intermediates such as ammonia, hydrogen sulfide, orthophosphates, and various salts, all of which must be properly controlled or captured. In addition, atmospheric releases at locations off-site where bio-gas is shipped may negate or decrease the benefit of emissions controls on-site. Thus, while devices such as Selective Catalyst Reduction (SCR) units can reduce NOx emissions and proper treatment system operation can control intermediates, improper design or operation may lead to violations of federal, state, and local air quality regulations as well as release of toxic air contaminants.

With regard to water quality, it is critical that project developers and managers ensure digester integrity and fully consider and address post-digestion management of the effluent in order to avoid contamination of local waterways and groundwater resources. Catastrophic digester failures; leakage from pipework and tanks; and lack of containment in waste storage areas are all examples of potential problems. Further, application of improperly treated digestate and/or improper application timing or rates of digestate to agricultural land may lead to increased nitrogen oxide emissions, soil contamination, and/or nutrient leaching, thus negating or reducing benefits of the project overall.

Project developers must not only follow the protocol to register GHG reductions with the Reserve, they must also comply with all local, state, and national air and water quality regulations. Projects must be designed and implemented to mitigate potential releases of pollutants such as those described, and project managers must acquire the appropriate local permits prior to installation to prevent violation of the law.

The Reserve agrees that GHG emission reduction projects should not undermine air and water quality efforts and will work with stakeholders to establish initiatives to meet both climate-related and localized environmental objectives.

# Appendix B Emission Factor Tables

**Table B.1.** Manure Management System Components

| System | Definition |
|---|---|
| Pasture/Range/ Paddock | The manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed. |
| Daily spread | Manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion. |
| Solid storage | The storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation. |
| Dry lot | A paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically. |
| Liquid/Slurry | Manure is stored as excreted or with some minimal addition of water in either tanks or earthen ponds outside the animal housing, usually for periods less than one year. Per IPCC Guidelines, if manure contains less than 20% dry matter it can be considered liquid. |
| Uncovered anaerobic lagoon | A type of liquid storage system designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields. |
| Pit storage below animal confinements | Collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility, usually for periods less than one year. |
| Anaerobic digester | Animal excreta with or without straw are collected and anaerobically digested in a large containment vessel or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO2 and CH4, which is captured and flared or used as a fuel. |
| Burned for fuel | The dung and urine are excreted on fields. The sun dried dung cakes are burned for fuel. |
| Cattle and Swine deep bedding | As manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture. |
| Composting – In-vessel* | Composting, typically in an enclosed channel, with forced aeration and continuous mixing. |
| Composting – Static pile* | Composting in piles with forced aeration but no mixing. |
| Composting – Intensive windrow* | Composting in windrows with regular (at least daily) turning for mixing and aeration. |
| Composting – Passive windrow* | Composting in windrows with infrequent turning for mixing and aeration. |
| Aerobic treatment | The biological oxidation of manure collected as a liquid with either forced or natural aeration. Natural aeration is limited to aerobic and facultative ponds and wetland systems and is due primarily to photosynthesis. Hence, these systems typically become anoxic during periods without sunlight. |

*Composting is the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production.

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 10: Emissions from Livestock and Manure Management, Table 10.18: Definitions of Manure Management Systems, p. 10.49.

**Table B.2.** Livestock Categories and Typical Animal Mass

| Livestock Category (L) | Livestock Typical Animal Mass (TAM) in kg | |
|---|---|---|
| | 2006 - 2008 | 2009 - 2010 |
| Dairy cows (on feed) | 604[b] | 680[c] |
| Non-milking dairy cows (on feed) | 684[a] | 684[a] |
| Heifers (on feed) | 476[b] | 407[c] |
| Bulls (grazing) | 750[b] | 750[c] |
| Calves (grazing) | 118[b] | 118[c] |
| Heifers (grazing) | 420[b] | 351[c] |
| Cows (grazing) | 533[b] | 582.5[c] |
| Nursery swine | 12.5[a] | 12.5[a] |
| Grow/finish swine | 70[a] | 70[a] |
| Breeding swine | 198[b] | 198[c] |

Sources for TAM:
[a.] American Society of Agricultural Engineers (ASAE) Standards 2005, ASAE D384.2.
[b.] Environmental Protection Agency (EPA), Inventory of US GHG Emissions and Sinks 1990-2006 (2007), Annex 3, Table A-161, pg. A-195.
[c.] Environmental Protection Agency (EPA), Inventory of US GHG Emissions and Sinks 1990-2010 (2012), Annex 3, Table A-191, pg. A-246.

**Table B.3.** Volatile Solids and Maximum Methane Potential by Livestock Category

| Livestock category (L) | $VS_L$ (kg/day/1000 kg mass) | $B_{0,L}$ [b] ($m^3$ $CH_4$/kg VS added) |
|---|---|---|
| Dairy cows | See Appendix B, Tables 5a-e | 0.24 |
| Non-milking dairy cows | 5.56 | 0.24 |
| Heifers | See Appendix B, Tables 5a-e | 0.17 |
| Bulls (grazing) | 6.04[b] | 0.17 |
| Calves (grazing) | 6.41[b] | 0.17 |
| Heifers (grazing) | See Appendix B, Tables 5a-e | 0.17 |
| Cows (grazing) | See Appendix B, Tables 5a-e | 0.17 |
| Nursery swine | 8.89[b] | 0.48 |
| Grow/finish swine | 5.36[b] | 0.48 |
| Breeding swine | 2.71[b] | 0.35 |

[a.] American Society of Agricultural Engineers (ASAE) Standards 2005, ASAE D384.2, $VS_L$(kg/day per animal) from table 1.b (p.2) converted to (kg/day/1000 kg mass) using average Live Weight (kg)values from table 5c (p.7).
[b.] Environmental Protection Agency (EPA) – Climate Leaders Draft Manure Offset Protocol, October 2006, Table IIa: Animal Waste Characteristics (VS, $B_0$, and $N_{ex}$ rates), p. 18.

**Table B.4.** Biogas Collection Efficiency by Digester Type

| Digester Type | Cover Type | Biogas Collection Efficiency (BCE) as a Decimal |
|---|---|---|
| Covered Anaerobic Lagoon | Bank-to-Bank, impermeable | 0.95 |
| | Partial area (modular), impermeable | (0.95) x (% area covered) |
| Complete mix, plug flow, or fixed film digester | Enclosed vessel | 0.98 |
| Two stages of differing types | With flow metered for each stage | $\frac{(BCE1) \times (Gasflow1) + (BCE2) \times (Gasflow2)}{Total\ biogas\ flow}$ |
| | No separate flow metering | $(BCE1) \times 0.7 + (BCE2) \times 0.3$ |

Adapted from: U.S. EPA Climate Leaders, Offset Project Methodology for Managing Manure and Biogas Recovery Systems, 2008. Table IIf (original table has been expanded upon).

**Table B.5a.** 2010 Volatile Solid Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

| State | VS Dairy Cow | VS Heifer | VS Heifer-Grazing | VS Cows-Grazing |
|---|---|---|---|---|
| Alabama | 8.99 | 8.43 | 8.53 | 7.82 |
| Alaska | 7.98 | 8.43 | 9.98 | 8.89 |
| Arizona | 11.47 | 8.43 | 9.77 | 8.89 |
| Arkansas | 8.30 | 8.43 | 8.48 | 7.82 |
| California | 11.27 | 8.43 | 9.48 | 8.89 |
| Colorado | 11.54 | 8.43 | 9.27 | 8.89 |
| Connecticut | 10.22 | 8.43 | 8.62 | 7.87 |
| Delaware | 9.53 | 8.43 | 8.53 | 7.87 |
| Florida | 10.26 | 8.43 | 8.63 | 7.82 |
| Georgia | 10.03 | 8.43 | 8.49 | 7.82 |
| Hawaii | 8.43 | 8.43 | 9.77 | 8.89 |
| Idaho | 11.24 | 8.43 | 9.41 | 8.89 |
| Illinois | 10.19 | 8.43 | 7.78 | 7.47 |
| Indiana | 10.54 | 8.43 | 7.91 | 7.47 |
| Iowa | 10.67 | 8.43 | 7.64 | 7.47 |
| Kansas | 10.74 | 8.43 | 7.61 | 7.47 |
| Kentucky | 9.11 | 8.43 | 8.40 | 7.82 |
| Louisiana | 7.98 | 8.43 | 8.63 | 7.82 |
| Maine | 9.94 | 8.43 | 8.51 | 7.87 |
| Maryland | 10.00 | 8.43 | 8.51 | 7.87 |
| Massachusetts | 9.67 | 8.43 | 8.53 | 7.87 |
| Michigan | 11.42 | 8.43 | 7.83 | 7.47 |
| Minnesota | 10.25 | 8.43 | 7.83 | 7.47 |
| Mississippi | 8.59 | 8.43 | 8.53 | 7.82 |
| Missouri | 8.81 | 8.43 | 7.97 | 7.47 |
| Montana | 10.63 | 8.43 | 8.42 | 7.82 |
| Nebraska | 10.38 | 8.43 | 9.25 | 8.89 |
| Nevada | 11.08 | 8.43 | 8.01 | 7.47 |
| New Hampshire | 10.40 | 8.43 | 9.62 | 8.89 |
| New Jersey | 9.69 | 8.43 | 8.45 | 7.87 |
| New Mexico | 11.81 | 8.43 | 8.43 | 7.87 |
| New York | 10.69 | 8.43 | 9.50 | 8.89 |
| North Carolina | 10.54 | 8.43 | 8.61 | 7.87 |
| North Dakota | 9.92 | 8.43 | 8.31 | 7.82 |
| Ohio | 10.27 | 8.43 | 7.95 | 7.47 |
| Oklahoma | 9.59 | 8.43 | 7.90 | 7.47 |
| Oregon | 10.54 | 8.43 | 8.33 | 7.82 |
| Pennsylvania | 10.39 | 8.43 | 9.56 | 8.89 |
| Rhode Island | 9.76 | 8.43 | 8.66 | 7.87 |
| South Carolina | 10.02 | 8.43 | 8.61 | 7.87 |
| South Dakota | 10.59 | 8.43 | 8.19 | 7.82 |
| Tennessee | 9.56 | 8.43 | 8.12 | 7.47 |
| Texas | 10.87 | 8.43 | 8.21 | 7.82 |
| Utah | 10.86 | 8.43 | 8.42 | 7.82 |
| Vermont | 10.00 | 8.43 | 9.56 | 8.89 |
| Virginia | 10.09 | 8.43 | 8.52 | 7.87 |
| Washington | 11.50 | 8.43 | 8.25 | 7.82 |
| West Virginia | 9.15 | 8.43 | 9.73 | 8.89 |
| Wisconsin | 10.63 | 8.43 | 7.96 | 7.47 |
| Wyoming | 10.46 | 8.43 | 9.62 | 8.89 |

Source: Environmental Protection Agency (EPA). U.S. Inventory of GHG Sources and Sinks 1990-2010 (2012), Annex 3, Table A-192, page A-237.

**Table B.5b.** 2009 Volatile Solid Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

| State | VS Dairy Cow | VS Heifer | VS Heifer-Grazing | VS Cows-Grazing |
|---|---|---|---|---|
| Alabama | 9.13 | 8.42 | 8.61 | 7.90 |
| Alaska | 7.43 | 8.42 | 11.51 | 10.15 |
| Arizona | 11.35 | 8.42 | 11.23 | 10.15 |
| Arkansas | 8.24 | 8.42 | 8.53 | 7.87 |
| California | 10.97 | 8.42 | 8.13 | 7.70 |
| Colorado | 11.37 | 8.42 | 7.42 | 7.27 |
| Connecticut | 10.05 | 8.42 | 8.53 | 7.77 |
| Delaware | 9.54 | 8.42 | 8.29 | 7.77 |
| Florida | 10.08 | 8.42 | 8.71 | 7.90 |
| Georgia | 10.24 | 8.42 | 8.61 | 7.90 |
| Hawaii | 8.70 | 8.42 | 11.32 | 10.15 |
| Idaho | 11.07 | 8.42 | 10.86 | 10.15 |
| Illinois | 10.10 | 8.42 | 8.10 | 7.77 |
| Indiana | 10.48 | 8.42 | 8.20 | 7.77 |
| Iowa | 10.55 | 8.42 | 7.98 | 7.77 |
| Kansas | 10.77 | 8.42 | 7.38 | 7.27 |
| Kentucky | 8.91 | 8.42 | 8.52 | 7.90 |
| Louisiana | 8.01 | 8.42 | 8.68 | 7.87 |
| Maine | 9.86 | 8.42 | 8.43 | 7.77 |
| Maryland | 9.92 | 8.42 | 8.32 | 7.77 |
| Massachusetts | 9.71 | 8.42 | 8.43 | 7.77 |
| Michigan | 11.18 | 8.42 | 8.15 | 7.77 |
| Minnesota | 10.21 | 8.42 | 8.17 | 7.77 |
| Mississippi | 8.82 | 8.42 | 8.60 | 7.90 |
| Missouri | 8.83 | 8.42 | 8.33 | 7.77 |
| Montana | 10.42 | 8.42 | 7.83 | 7.27 |
| Nebraska | 10.36 | 8.42 | 7.42 | 7.27 |
| Nevada | 10.99 | 8.42 | 11.14 | 10.15 |
| New Hampshire | 10.30 | 8.42 | 8.37 | 7.77 |
| New Jersey | 9.81 | 8.42 | 8.34 | 7.77 |
| New Mexico | 11.74 | 8.42 | 11.06 | 10.15 |
| New York | 10.46 | 8.42 | 8.20 | 7.77 |
| North Carolina | 10.55 | 8.42 | 8.60 | 7.90 |
| North Dakota | 9.46 | 8.42 | 7.68 | 7.27 |
| Ohio | 10.06 | 8.42 | 8.28 | 7.77 |
| Oklahoma | 9.55 | 8.42 | 8.32 | 7.87 |
| Oregon | 10.36 | 8.42 | 11.03 | 10.15 |
| Pennsylvania | 10.25 | 8.42 | 8.20 | 7.77 |
| Rhode Island | 9.78 | 8.42 | 8.55 | 7.77 |
| South Carolina | 10.29 | 8.42 | 8.64 | 7.90 |
| South Dakota | 10.48 | 8.42 | 7.57 | 7.27 |
| Tennessee | 9.53 | 8.42 | 8.58 | 7.90 |
| Texas | 10.73 | 8.42 | 8.26 | 7.87 |
| Utah | 10.74 | 8.42 | 11.11 | 10.15 |
| Vermont | 9.93 | 8.42 | 8.23 | 7.77 |
| Virginia | 10.08 | 8.42 | 8.56 | 7.90 |
| Washington | 11.39 | 8.42 | 10.93 | 10.15 |
| West Virginia | 8.85 | 8.42 | 8.35 | 7.77 |
| Wisconsin | 10.46 | 8.42 | 8.33 | 7.77 |
| Wyoming | 10.08 | 8.42 | 7.72 | 7.27 |

Source: Environmental Protection Agency (EPA). U.S. Inventory of GHG Sources and Sinks 1990-2009 (2011), Annex 3, Table A-186, page A-225.

**Table B.5c.** 2008 Volatile Solid Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

| State | VS Dairy Cow | VS Heifer | VS Heifer-Grazing | VS Cows-Grazing |
|---|---|---|---|---|
| Alabama | 8.40 | 8.35 | 7.81 | 7.02 |
| Alaska | 7.30 | 8.35 | 10.05 | 9.02 |
| Arizona | 10.37 | 8.35 | 10.34 | 9.02 |
| Arkansas | 7.59 | 8.35 | 7.86 | 7.00 |
| California | 10.02 | 8.35 | 7.95 | 6.85 |
| Colorado | 10.25 | 8.35 | 7.69 | 6.46 |
| Connecticut | 9.22 | 8.35 | 7.67 | 6.90 |
| Delaware | 8.63 | 8.35 | 7.72 | 6.90 |
| Florida | 8.90 | 8.35 | 7.75 | 7.02 |
| Georgia | 9.07 | 8.35 | 7.85 | 7.02 |
| Hawaii | 7.00 | 8.35 | 10.26 | 9.02 |
| Idaho | 10.11 | 8.35 | 10.82 | 9.02 |
| Illinois | 9.07 | 8.35 | 8.07 | 6.91 |
| Indiana | 9.38 | 8.35 | 7.98 | 6.91 |
| Iowa | 9.46 | 8.35 | 8.27 | 6.91 |
| Kansas | 9.63 | 8.35 | 7.75 | 6.46 |
| Kentucky | 7.89 | 8.35 | 7.91 | 7.02 |
| Louisiana | 7.39 | 8.35 | 7.73 | 7.00 |
| Maine | 8.99 | 8.35 | 7.76 | 6.90 |
| Maryland | 9.02 | 8.35 | 7.76 | 6.90 |
| Massachusetts | 8.63 | 8.35 | 7.74 | 6.90 |
| Michigan | 10.05 | 8.35 | 7.99 | 6.91 |
| Minnesota | 9.17 | 8.35 | 8.04 | 6.91 |
| Mississippi | 8.19 | 8.35 | 7.82 | 7.02 |
| Missouri | 8.02 | 8.35 | 7.85 | 6.91 |
| Montana | 9.03 | 8.35 | 7.17 | 6.46 |
| Nebraska | 9.09 | 8.35 | 7.71 | 6.46 |
| Nevada | 9.65 | 8.35 | 10.49 | 9.02 |
| New Hampshire | 9.44 | 8.35 | 7.74 | 6.90 |
| New Jersey | 8.51 | 8.35 | 7.89 | 6.90 |
| New Mexico | 10.34 | 8.35 | 10.56 | 9.02 |
| New York | 9.42 | 8.35 | 8.02 | 6.90 |
| North Carolina | 9.38 | 8.35 | 7.83 | 7.02 |
| North Dakota | 8.40 | 8.35 | 7.43 | 6.46 |
| Ohio | 9.01 | 8.35 | 7.93 | 6.91 |
| Oklahoma | 8.58 | 8.35 | 8.08 | 7.00 |
| Oregon | 9.40 | 8.35 | 10.54 | 9.02 |
| Pennsylvania | 9.26 | 8.35 | 8.00 | 6.90 |
| Rhode Island | 8.94 | 8.35 | 7.60 | 6.90 |
| South Carolina | 9.05 | 8.35 | 7.81 | 7.02 |
| South Dakota | 9.45 | 8.35 | 7.50 | 6.46 |
| Tennessee | 8.60 | 8.35 | 7.86 | 7.02 |
| Texas | 9.51 | 8.35 | 8.21 | 7.00 |
| Utah | 9.70 | 8.35 | 10.51 | 9.02 |
| Vermont | 9.03 | 8.35 | 7.89 | 6.90 |
| Virginia | 9.02 | 8.35 | 7.87 | 7.02 |
| Washington | 10.36 | 8.35 | 10.77 | 9.02 |
| West Virginia | 8.13 | 8.35 | 7.74 | 6.90 |
| Wisconsin | 9.34 | 8.35 | 7.87 | 6.91 |
| Wyoming | 9.29 | 8.35 | 7.30 | 6.46 |

Source: Environmental Protection Agency (EPA). U.S. Inventory of GHG Sources and Sinks 1990-2008 (2010), Annex 3, Table A-181, page A-213.

*For VS values for reporting years prior to 2008, please refer to the Livestock Project Protocol V3.0, Appendix B.*

**Table B.6.** IPCC 2006 Methane Conversion Factors by Manure Management System Component/Methane Source 'S' [39]

| MCF Values by Temperature for Manure Management Systems | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Average annual temperature (°C) | | | | | | | | | | | | | | | | | | | |
| | Cool | | | | | Temperate | | | | | | | | | | | Warm | | | |
| **System[a]** | **<10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** | **27** | **>28** | **Source and comments** |
| Pasture/Range/Paddock | 0.010 | | | | | 0.015 | | | | | | | | | | | 0.020 | | | Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994). |
| Daily spread | 0.001 | | | | | 0.005 | | | | | | | | | | | 0.010 | | | Hashimoto and Steed (1993). |
| Solid storage | 0.02 | | | | | 0.04 | | | | | | | | | | | 0.05 | | | Judgment of IPCC Expert Group in combination with Amon et al. (2001), which shows emissions of approximately 2% in winter and 4% in summer. Warm climate is based on judgment of IPCC Expert Group and Amon et al. (1998). |
| Dry lot | 0.010 | | | | | 0.015 | | | | | | | | | | | 0.020 | | | Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994). |
| Liquid/slurry w/natural crust cover[40] | 0.10 | 0.11 | 0.13 | 0.14 | 0.15 | 0.17 | 0.18 | 0.20 | 0.22 | 0.24 | 0.26 | 0.29 | 0.31 | 0.34 | 0.37 | 0.41 | 0.44 | 0.48 | 0.50 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001) and Sommer (2000). The estimated reduction due to the crust cover (40%) is an annual average value based on a limited data set and can be highly variable dependent on temperature, rainfall, and composition. |
| Liquid/slurry uncovered | 0.17 | 0.19 | 0.20 | 0.22 | 0.25 | 0.27 | 0.29 | 0.32 | 0.35 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.65 | 0.71 | 0.78 | 0.80 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). |
| Uncovered anaerobic lagoon | 0.66 | 0.68 | 0.70 | 0.71 | 0.73 | 0.74 | 0.75 | 0.76 | 0.77 | 0.77 | 0.78 | 0.78 | 0.78 | 0.79 | 0.79 | 0.79 | 0.79 | 0.80 | 0.80 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Uncovered lagoon MCFs vary based on several factors, including temperature, retention time, and loss of volatile solids from the system (through removal of lagoon effluent and/or solids). |
| Pit storage below animal confinements (<1 month) | 0.03 | | | | | 0.03 | | | | | | | | | | | 0.03 | | | Judgment of IPCC Expert Group in combination with Moller et al. (2004) and Zeeman (1994). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions. |
| Pit storage below animal confinements (>1 month) | 0.17 | 0.19 | 0.20 | 0.22 | 0.25 | 0.27 | 0.29 | 0.32 | 0.35 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.65 | 0.71 | 0.78 | 0.80 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions. |

[39] Adapted from 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 10: Emissions from Livestock and Manure Management, Table 10.17. MCF values shall be chosen based on the average temperature at the site for an entire calendar year, even if the reporting period does not exactly cover a calendar year.

[40] A "natural crust cover" is a naturally-forming layer that covers the majority of the liquid surface at a thickness sufficient to support communities of oxidizing bacteria, and which persists throughout the year. Evidence of such a cover (including the area covered, thickness, and persistence) must be provided by the project developer during verification in order to justify the use of this MCF value.

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anaerobic digester | 0 - 1 | | | | | 0 - 1 | | | | | | | | | | | 0 - 1 | | | Should be subdivided in different categories, considering amount of recovery of the biogas, flaring of the biogas and storage after digestion. Calculation with Formula 1. |
| Burned for fuel | 0.10 | | | | | 0.10 | | | | | | | | | | | 0.10 | | | Judgment of IPCC Expert Group in combination with Safley et al. (1992). |
| Cattle and swine deep bedding (<1 month) | 0.03 | | | | | 0.03 | | | | | | | | | | | 0.30 | | | Judgment of IPCC Expert Group in combination with Moller et al. (2004). Expect emissions to be similar, and possibly greater, than pit storage, depending on organic content and moisture content. |
| Cattle and swine deep bedding (>1 month) | 0.17 | 0.19 | 0.20 | 0.22 | 0.25 | 0.27 | 0.29 | 0.32 | 0.35 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.65 | 0.71 | 0.78 | 0.90 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). |
| Composting - in-vessel or aerated static pile[b] | 0.005 | | | | | 0.005 | | | | | | | | | | | 0.005 | | | Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are less than half of solid storage. Not temperature dependant. |
| Composting - passive or intensive windrow[b] | 0.005 | | | | | 0.010 | | | | | | | | | | | 0.015 | | | Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are slightly less than solid storage. Less temperature dependant. |
| Aerobic treatment | 0.00 | | | | | 0.00 | | | | | | | | | | | 0.00 | | | MCFs are near zero. Aerobic treatment can result in the accumulation of sludge which may be treated in other systems. Sludge requires removal and has large VS values. It is important to identify the next management process for the sludge and estimate the emissions from that management process if significant. |

[a] Definitions for manure management systems are provided in Table B.1.
[b] Composting is the biological oxidation of a solid waste, including manure, usually with bedding or another organic carbon source, typically at thermophilic temperatures produced by microbial heat production.

**Table B.7.** Biogas Destruction Efficiency Default Values by Destruction Device

If available, the official source tested methane destruction efficiency shall be used in place of the default methane destruction efficiency. Otherwise, project developers have the option to use either the default methane destruction efficiencies provided, or the site specific methane destruction efficiencies, for each of the combustion devices used in the project case performed on an annual basis. Site-specific values must be provided by an independent air emissions testing body that is accredited by a state or local regulatory agency, or the Stack Testing Accreditation Council. Where a state/region does not have an appropriate accreditation system or accredited service providers, the project developer may look to another state/region to find suitably qualified service providers.

| Biogas Destruction Device | Biogas Destruction Efficiency (BDE)* |
|---|---|
| Open Flare | 0.96[2] |
| Enclosed Flare | 0.995[2] |
| Lean-burn Internal Combustion Engine | 0.936[2] |
| Rich-burn Internal Combustion Engine | 0.995[2] |
| Boiler | 0.98[2] |
| Microturbine or large gas turbine | 0.995[2] |
| Upgrade and use of gas as CNG/LNG fuel | 0.95[2] |
| Upgrade and injection into natural gas transmission and distribution pipeline | 0.98[3] |
| Direct pipeline to an end-user | Per corresponding destruction device |

Source:
[1] Seebold, J.G., et al., Reaction Efficiency of Industrial Flares, 2003
[2] The default destruction efficiencies for this source are based on a preliminary set of actual source test data provided by the Bay Area Air Quality Management District. The default destruction efficiency values are the lesser of the twenty fifth percentile of the data provided or 0.995. These default destruction efficiencies may be updated as more source test data are made available to the Reserve.
[3] The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas destroyed of 99.5% (Reference Manual, Table 1.6, page 1.29). It also gives a value for emissions from processing, transmission and distribution of gas which would be a very conservative estimate for losses in the pipeline and for leakage at the end user (Reference Manual, Table 1.58, page 1.121). These emissions are given as 118,000kgCH4/PJ on the basis of gas consumption, which is 0.6%. Leakage in the residential and commercial sectors is stated to be 0 to 87,000kgCH4/PJ, which equates to 0.4%, and in industrial plants and power station the losses are 0 to 175,000kg/CH4/PJ, which is 0.8%. These leakage estimates are compounded and multiplied. The methane destruction efficiency for landfill gas injected into the natural gas transmission and distribution system can now be calculated as the product of these three efficiency factors, giving a total efficiency of (99.5% * 99.4% * 99.6%) 98.5% for residential and commercial sector users, and (99.5% * 99.4% * 99.2%) 98.1% for industrial plants and power stations.[41]

[41] GE AES Greenhouse Gas Services, Landfill Gas Methodology, Version 1.0 (July 2007).

**Table B.8.** $CO_2$ Emission Factors for Fossil Fuel Use

| Fuel Type | Heat Content | Carbon Content (Per Unit Energy) | Fraction Oxidized | $CO_2$ Emission Factor (Per Unit Energy) | $CO_2$ Emission Factor (Per Unit Mass or Volume) |
|---|---|---|---|---|---|
| **Coal and Coke** | **MMBTU / Short ton** | **kg C / MMBTU** | | **kg $CO_2$ / MMBTU** | **kg $CO_2$ / Short ton** |
| Anthracite Coal | 25.09 | 28.26 | 1.00 | 103.62 | 2,599.83 |
| Bituminous Coal | 24.93 | 25.49 | 1.00 | 93.46 | 2,330.04 |
| Sub-bituminous Coal | 17.25 | 26.48 | 1.00 | 97.09 | 1,674.86 |
| Lignite | 14.21 | 26.30 | 1.00 | 96.43 | 1,370.32 |
| Unspecified (Residential/ Commercial) | 22.05 | 26.00 | 1.00 | 95.33 | 2,102.29 |
| Unspecified (Industrial Coking) | 26.27 | 25.56 | 1.00 | 93.72 | 2,462.12 |
| Unspecified (Other Industrial) | 22.05 | 25.63 | 1.00 | 93.98 | 2,072.19 |
| Unspecified (Electric Utility) | 19.95 | 25.76 | 1.00 | 94.45 | 1,884.53 |
| Coke | 24.80 | 31.00 | 1.00 | 113.67 | 2,818.93 |
| **Natural Gas** (By Heat Content) | **BTU / Standard $ft^3$** | **kg C / MMBTU** | | **kg $CO_2$ / MMBTU** | **kg $CO_2$ / Standard $ft^3$** |
| 975 to 1,000 Btu / Standard $ft^3$ | 975 – 1,000 | 14.73 | 1.00 | 54.01 | Varies |
| 1,000 to 1,025 Btu / Standard $ft^3$ | 1,000 – 1,025 | 14.43 | 1.00 | 52.91 | Varies |
| 1,025 to 1,050 Btu / Standard $ft^3$ | 1,025 – 1,050 | 14.47 | 1.00 | 53.06 | Varies |
| 1,050 to 1,075 Btu / Standard $ft^3$ | 1,050 – 1,075 | 14.58 | 1.00 | 53.46 | Varies |
| 1,075 to 1,100 Btu / Standard $ft^3$ | 1,075 – 1,100 | 14.65 | 1.00 | 53.72 | Varies |
| Greater than 1,100 Btu / Standard $ft^3$ | > 1,100 | 14.92 | 1.00 | 54.71 | Varies |
| Weighted U.S. Average | 1,029 | 14.47 | 1.00 | 53.06 | 0.0546 |
| **Petroleum Products** | **MMBTU / Barrel** | **kg C / MMBTU** | | **kg $CO_2$ / MMBTU** | **kg $CO_2$ / gallon** |
| Asphalt & Road Oil | 6.636 | 20.62 | 1.00 | 75.61 | 11.95 |
| Aviation Gasoline | 5.048 | 18.87 | 1.00 | 69.19 | 8.32 |
| Distillate Fuel Oil (#1, 2, and 4) (diesel) | 5.825 | 19.95 | 1.00 | 73.15 | 10.15 |
| Jet Fuel | 5.670 | 19.33 | 1.00 | 70.88 | 9.57 |
| Kerosene | 5.670 | 19.72 | 1.00 | 72.31 | 9.76 |
| LPG (average for fuel use) | 3.849 | 17.23 | 1.00 | 63.16 | 5.79 |
| Propane | 3.824 | 17.20 | 1.00 | 63.07 | 5.74 |
| Ethane | 2.916 | 16.25 | 1.00 | 59.58 | 4.14 |
| Isobutene | 4.162 | 17.75 | 1.00 | 65.08 | 6.45 |
| n-Butane | 4.328 | 17.72 | 1.00 | 64.97 | 6.70 |
| Lubricants | 6.065 | 20.24 | 1.00 | 74.21 | 10.72 |
| Motor Gasoline | 5.218 | 19.33 | 1.00 | 70.88 | 8.81 |
| Residual Fuel Oil (#5 and 6) | 6.287 | 21.49 | 1.00 | 78.80 | 11.80 |
| Crude Oil | 5.800 | 20.33 | 1.00 | 74.54 | 10.29 |
| Naphtha (<401°F) | 5.248 | 18.14 | 1.00 | 66.51 | 8.31 |
| Natural Gasoline | 4.620 | 18.24 | 1.00 | 66.88 | 7.36 |
| Other Oil (>401°F) | 5.825 | 19.95 | 1.00 | 73.15 | 10.15 |
| Pentanes Plus | 4.620 | 18.24 | 1.00 | 66.88 | 7.36 |
| Petrochemical Feedstocks | 5.428 | 19.37 | 1.00 | 71.02 | 9.18 |
| Petroleum Coke | 6.024 | 27.85 | 1.00 | 102.12 | 14.65 |
| Still Gas | 6.000 | 17.51 | 1.00 | 64.20 | 9.17 |
| Special Naphtha | 5.248 | 19.86 | 1.00 | 72.82 | 9.10 |
| Unfinished Oils | 5.825 | 20.33 | 1.00 | 74.54 | 10.34 |
| Waxes | 5.537 | 19.81 | 1.00 | 72.64 | 9.58 |

Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-2 except:
Default $CO_2$ emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default $CO_2$ emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

**Table B.9.** Volatile Solids Removed Through Solids Separation[42]

| Type of Solids Separation | Volatile Solids Removed (fraction) |
|---|---|
| Gravity | 0.45 |
| Mechanical: | |
| Stationary screen | 0.17 |
| Vibrating screen | 0.15 |
| Screw press | 0.25 |
| Centrifuge | 0.50 |
| Roller drum | 0.25 |
| Belt press/screen | 0.50 |

**Table B.10.** Baseline Assumptions for Greenfield Projects[43]

| Baseline Assumption | Dairy Cattle Operations | | Swine Operations |
|---|---|---|---|
| | >200 Mature Dairy Cows | <200 Mature Dairy Cows | |
| **Anaerobic manure storage system** | Flush system into an anaerobic lagoon with >30 day retention time | Flush system into an anaerobic lagoon with >30 day retention time | Flush system into an anaerobic lagoon with >30 day retention time |
| **Non-anaerobic manure storage system(s)** | Solids storage | Solids Storage | Solids Storage |
| **$MS_L$** | 90% lagoon<br>10% solids storage | 50% lagoon<br>50% solids storage | 95% lagoon<br>5% solids storage |
| **Lagoon cleaning schedule** | Annually, in September | Annually, in September | Annually, in September |

[42] U.S.EPA National Pollutant Discharge Elimination System (NPDES) Development Document, Chapter 5, "Industry Subcategorization for Effluent Limitations Guidelines and Standards". Adapted from Moser et al. (1999).
[43] The simplified assumptions contained within this table are based on the waste management system data compiled by the U.S. Environmental Protection Agency for the development of Table A-194 in Annex 3 of the U.S. Inventory of GHG Sources and Sinks 1990-2010 (2012).

# Appendix C Summary of Performance Standard Development

The analysis to establish a performance standard for the U.S. Livestock Project Protocol was undertaken by Science Applications International Corporation (SAIC) and independent consultant Kathryn Bickel Goldman. It took place at the end of 2006. The analysis culminated in a paper that provided a performance standard recommendation to support the Reserve's protocol development process, which the Reserve has incorporated into the protocol's eligibility rules (see Section 33). This analysis was re-visited during the development of Version 4.0 of the protocol and, although there was no recommended change to the performance standard, this appendix has been updated to reflect more recent data and analysis.

The purpose of a performance standard is to establish a threshold that is significantly better than average GHG production for a specified service, which, if met or exceeded by a project developer, satisfies the criterion of "additionality." This protocol focuses on the following direct emission reduction activity: avoiding methane emissions from the anaerobic storage and treatment of livestock manure. Therefore, in this case the methane emissions correspond to GHG production, and manure treatment/storage correspond to the specified service.

The analysis to establish the performance standard evaluated U.S.- and California-specific data on dairy and swine manure management systems. Ultimately, it recommended a practice-based/technology-specific GHG emissions performance standard – i.e. the installation of a manure digester (or Biogas Control System (BCS), more generally). The paper was composed of the following sections:

- The livestock industry in the U.S. and California
- Livestock manure management practices
- GHG emissions from livestock manure management
- Data on livestock manure management practices in the U.S. and California
- Current and anticipated regulations in California impacting manure management practices
- Recommendation for a performance threshold for livestock operations
- Considerations for baseline determinations

The initial analysis from that paper can be found in earlier versions of the U.S. Livestock Project Protocol Performance Standard Appendix.[44] In this updated Performance Standard Appendix, The additional, California-specific analysis showed adoption rates similar to the rest of the country, and thus has been removed from this document to reflect the Reserve's decision to apply the same performance standard to all operations across the United States. Beef facility and animal information has also been removed as beef operations are not currently eligible under the Protocol.

[44] Climate Action Reserve U.S. Livestock Project Protocol V1.0-3.0, Appendix C, http://www.climateactionreserve.org/how/protocols/us-livestock/

## C.1 Analysis of Common Practice

### C.1.1 U.S. Data on Manure Management Practices

For the initial performance standard analysis, data from the Draft EPA Climate Leaders Offset Protocol for Managing Manure with Biogas Recovery Systems (2006) were used to assess national-level manure management practices. That protocol relied on data describing farm distribution and manure management systems from the Manure Management portion of the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2004 and used data on the number of farms by farm size and geographic location from the 2002 Census of Agriculture.[45]

Information compiled for the EPA's U.S. GHG Inventory also provided a breakdown of the assumed predominant manure management systems in use for dairy and swine operations. Table C.1 and Table C.3 show data compiled for the systems in place in 2006. Table C.2 and Table C.4 show the Reserve's approximate recreation of the same analysis using the most recently published numbers.[46]

**Table C.1.** Dairy and Swine Operations in the U.S. by Manure Management System (2006)

| Animal | Number of Operations by Manure Management System | | | | | | |
|---|---|---|---|---|---|---|---|
| | P/R/P | Anaerobic Digester | Lagoon | Liquid/ Slurry | Solid Storage | Deep Pit | Total |
| Dairy | 72,487 | 62 | 4,453 | 4,345 | 9,494 | 1,147 | 91,989 |
| Swine | 53,230 | 18 | 6,571 | 6,303 | 1,129 | 11,643 | 78,894 |

Source: U.S. EPA Climate Leaders Offset Protocol for Managing Manure with Biogas Recovery Systems (2008), Table I.A.

**Table C.2.** Dairy and Swine Operations in the U.S. by Manure Management System (2012)

| Animal | Number of Operations by Manure Management System | | | | | | |
|---|---|---|---|---|---|---|---|
| | P/R/P | Anaerobic Digester | Lagoon | Liquid/ Slurry | Solid Storage | Deep Pit | Total |
| Dairy | 56,075 | 185* | 3,332 | 3,261 | 6,263 | 775 | 69,890 |
| Swine | 55,110 | 30 | 5,740 | 4,641 | 892 | 9,029 | 75,442 |

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture
* There are three systems in operation that digest both swine and dairy manure. For the purpose of this analysis they are considered as dairy.

[45] EPA GHG Inventory Reports in subsequent years (including 2010) still rely on the results of the 2002 Census for this data.
[46] The equivalent analysis based on the 2007 census is unavailable in the same format from the EPA Climate Leaders program. The Reserve performed a similar analysis using data for manure management from the Inventory of U.S. Greenhouse Gas Emissions and Sinks (2012), data on the prevalence of anaerobic digesters from the U.S. EPA's AgSTAR database (Sept. 2012), and data on the number of farms by farms size and geographic location from the 2007 Census of Agriculture, the results of which are Table C.2 and Table C.4. This analysis may not have been performed in precisely the same way as the EPA Climate Leaders Program analysis; however it serves the purpose of evaluating the current state of the dairy and swine manure management practices. The following classification assumptions were made: 1. digester projects associated with farms of size are classified by based on other information in the AgSTAR database, if available, or assumed to be in the medium size class; 2. farms employing anaerobic digesters are subtracted from the USDA counts based on "Baseline System" or other information in the AgSTAR database, if available. Where the "Baseline System" is categorized as "Storage Tank or Pond or Pit," the farm is assumed to belong in the "Liquid/Slurry" category for Dairy and the "Deep Pit" category for Swine.

The distribution of livestock across different sized operations can be an important criterion when developing a livestock manure management performance standard. There is a general relationship between manure management practices and operation size, where larger operations (in terms of livestock numbers) tend to use manure management systems that treat and store waste in liquid form (i.e. flush or scrape/slurry systems), particularly in dairy and swine operations.[47]

**Table C.3.** Dairy and Swine Operations by Size and Manure Management System (2006)

| Animal | Number of Operations by Farm Size and Manure Management System | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Farm Size | P/R/P | Anaerobic Digester | Lagoon | Liquid/ Slurry | Solid Storage | Deep Pit | Total |
| Dairy | ≥500 head | 320 | 48 | 1,614 | 675 | 245 | - | 2,902 |
| | 200-499 | 3,213 | 9 | 617 | 652 | 54 | - | 4,546 |
| | 1-199 | 6,8954 | 5 | 2,223 | 3,017 | 9,195 | 1,147 | 84,541 |
| Swine | ≥2000 head | - | 14 | 2,581 | 1,084 | 297 | 2,774 | 6,749 |
| | 200-2000 | - | 3 | 3,990 | 5,219 | 832 | 8,869 | 18,913 |
| | 1-199 | 53,230 | 1 | - | - | - | - | 53,231 |

Source: U.S. 2002 Census of Agriculture.

**Table C.4.** Dairy and Swine Operations by Size and Manure Management System (2012)

| Animal | Number of Operations by Farm Size and Manure Management System | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Farm Size | P/R/P | Anaerobic Digester | Lagoon | Liquid/ Slurry | Solid Storage | Deep Pit | Total |
| Dairy | ≥500 head | 312 | 154 | 1,824 | 710 | 284 | - | 3,284 |
| | 200-499 | 3205 | 25 | 502 | 531 | 44 | - | 4,307 |
| | 1-199 | 52559 | 6 | 1,006 | 2,020 | 5,934 | 775 | 62,299 |
| Swine | ≥2000 head | - | 26 | 3,182 | 1,295 | 358 | 3,345 | 8,206 |
| | 200-2000 | - | 3 | 2,557 | 3,347 | 534 | 5,685 | 12,125 |
| | 1-199 | 55,110 | 1 | - | - | - | - | 55,111 |

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture.

According to the Interim Draft Winter 2006 AgSTAR Digest used for the initial analysis, of 91,988 dairy and 78,894 swine farm operations in the United States, a total of 80 anaerobic digesters were in operation: 62 (0.07%) for dairy manure and 18 (0.02%) for swine manure.

Data were also disaggregated in the Climate Leaders protocol to determine whether digester installation was a common practice in any animal production operation size range. As was shown in Table C.3, even at large animal production operations, very few digester systems were in place. At dairy farms with ≥500 head, only 1.7% of manure management systems included digesters, and of swine farms with >2000 head, only 0.2% had digesters.

[47] U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004 (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006.

The most current information from the AgSTAR database (September 2012) shows that the number of anaerobic digesters in operation or under construction has nearly tripled at dairy farms and increased by more than 50% at swine farms. In terms of prevalence as a manure management practice across farms however, the practice remains the exception, rather than the rule. Currently there are 185 digesters at dairy farms (0.14%), and 30 at swine farms (0.03%). The number of digesters at the largest farms increased the most significantly, with 154 digesters at dairy farms with ≥500 head (4.69%), and 26 at swine operations with ≥2000 head (0.32%). Of the 185 dairy farms with anaerobic digesters in operation, 84 have participated in GHG offset programs; eight of the 30 swine farms with anaerobic digester have participated in GHG offset programs. Table C.5 shows the distribution and percentages of digesters in operation or under construction by size farm, compared to farms with other manure management practices; Table C.6 shows the same distribution, but does not include the digesters at farms participating in GHG offset programs.

The "natural" market penetration of anaerobic digesters on livestock facilities can be considered as the percentage of farms that choose this management option without the incentive provided by GHG offset programs. Table C.6 shows that the natural market penetration of anaerobic digesters on dairy and swine facilities in the U.S. remains very low. The highest rate of adoption is among dairy farms with ≥500 head, at 2.31%. However, this number conservatively includes anaerobic digestion facilities that are currently under construction. As many if not all of these facilities may actually be installed in response to GHG offset programs (which is often not known until they are operational and become publicly listed in one of these programs), even this small rate of adoption is likely to be overestimated by this analysis. If the anaerobic digesters that are under construction are all assumed to be GHG offset projects, then the natural market penetration of anaerobic digesters on dairy facilities of ≥ 500 head drops to 1.71%.

**Table C.5.** Dairy and Swine Operations by Size and Manure Management System (2012)

| Animal | Number of Operations by Farm Size and Manure Management System | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Farm Size | P/R/P | Anaerobic Digester | Lagoon | Liquid/ Slurry | Solid Storage | Deep Pit | Total |
| Dairy | ≥500 head | 312<br>9.49% | 154<br>4.69% | 1,824<br>55.53% | 710<br>21.63% | 284<br>8.66% | -<br>- | 3,284 |
| | 200-499 | 3,205<br>74.41% | 25<br>0.58% | 502<br>11.66% | 531<br>12.32% | 44<br>1.03% | -<br>- | 4,307 |
| | 1-199 | 52,559<br>84.37% | 6<br>0.01% | 1,006<br>1.61% | 2,020<br>3.24% | 5,934<br>9.52% | 775<br>1.24% | 62,299 |
| | Total | 56,075<br>80.23% | 185<br>0.26% | 3,332<br>4.77% | 3,261<br>4.67% | 6,263<br>8.96% | 775<br>1.11% | 69,890 |
| Swine | ≥2000 head | -<br>- | 26<br>0.32% | 3,182<br>38.78% | 1,295<br>15.78% | 358<br>4.37% | 3,345<br>40.76% | 8,206 |
| | 200-1999 | -<br>- | 3<br>0.02% | 2,557<br>21.09% | 3,347<br>27.60% | 534<br>4.40% | 5,685<br>46.88% | 12,125 |
| | 1-199 | 55,110<br>99.998% | 1<br>0.002% | -<br>- | -<br>- | -<br>- | -<br>- | 55,111 |
| | Total | 55,110<br>73.05% | 30<br>0.04% | 5,740<br>7.61% | 4,641<br>6.15% | 892<br>1.18% | 9,029<br>11.97% | 75,442 |

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture.

**Table C.6.** Dairy and Swine Operations by Size and Manure Management System (2012)
Not including those participating in a GHG offset program.

| Animal | Number of Operations by Farm Size and Manure Management System | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Farm Size | P/R/P | Anaerobic Digester | Lagoon | Liquid/ Slurry | Solid Storage | Deep Pit | Total |
| Dairy | ≥500 head | 312<br>*9.73%* | 74<br>*2.31%* | 1,824<br>*56.91%* | 710<br>*22.17%* | 284<br>*8.88%* | -<br>- | 3,204 |
| | 200-499 | 3,205<br>*74.47%* | 21<br>*0.49%* | 502<br>*11.67%* | 531<br>*12.33%* | 44<br>*1.03%* | -<br>- | 4,303 |
| | 1-199 | 52,559<br>*84.37%* | 6<br>*0.01%* | 1,006<br>*1.61%* | 2,020<br>*3.24%* | 5,934<br>*9.52%* | 775<br>*1.24%* | 62,299 |
| | Total | 56,075<br>*80.33%* | 101<br>*0.14%* | 3,332<br>*4.77%* | 3,261<br>*4.67%* | 6,263<br>*8.97%* | 775<br>*1.11%* | 69,806 |
| Swine | ≥2000 head | -<br>- | 19<br>*0.23%* | 3,182<br>*38.81%* | 1,295<br>*15.79%* | 358<br>*4.37%* | 3,345<br>*40.80%* | 8,199 |
| | 200-1999 | -<br>- | 2<br>*0.02%* | 2,557<br>*21.09%* | 3,347<br>*27.60%* | 534<br>*4.40%* | 5,685<br>*46.89%* | 12,124 |
| | 1-199 | 55,110<br>*99.998%* | 1<br>*0.002%* | -<br>- | -<br>- | -<br>- | -<br>- | 55,111 |
| | Total | 55,110<br>*73.06%* | 22<br>*0.03%* | 5,740<br>*7.61%* | 4,641<br>*6.15%* | 892<br>*1.18%* | 9,029<br>*11.97%* | 75,434 |

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture, open GHG offset program registries.

Finally, as anaerobic digesters are most likely to be installed on livestock facilities that already utilize liquid-based manure management systems, it is useful to examine the market penetration among only these facilities. Table C.7 shows that, among the total facilities utilizing liquid manure management systems, the natural market penetration of anaerobic digesters is 1.35% for dairy farms and 0.11% for swine farms.[48] The highest rate, seen among dairy farms of ≥500 head, is 2.84%. This continues to be an extremely low rate of adoption for anaerobic digestion technology.

[48] There is seemingly 100% market penetration on swine farms with <200 animals, due to the fact that there was only one farm in the dataset utilizing liquid manure management, and it also had an anaerobic digester. A greater trend of adoption of anaerobic digestion cannot be drawn from this single farm.

**Table C.7.** Dairy and Swine Operations Utilizing Liquid Manure Management, by Size and Manure Management System (2012)
Not including those participating in a GHG offset program.

| Animal | Number of Operations by Farm Size Using Anaerobic Manure Management (Excluding GHG Offsets) | | | |
|---|---|---|---|---|
| | Farm Size | Anaerobic Digester | Liquid Manure Management | Total |
| Dairy | ≥500 head | 74<br>*2.84%* | 2,534<br>*97.16%* | 2,608 |
| | 200-499 | 21<br>*1.99%* | 1,033<br>*98.01%* | 1,054 |
| | 1-199 | 6<br>*0.16%* | 3,800<br>*99.84%* | 3,806 |
| | Total | 101<br>*1.35%* | 7,367<br>*98.65%* | 7,468 |
| Swine | ≥2000 head | 19<br>*0.24%* | 7,822<br>*99.76%* | 7,841 |
| | 200-1999 | 2<br>*0.02%* | 11,589<br>*99.98%* | 11,591 |
| | 1-199 | 1<br>*100.00%* | -<br>- | 1 |
| | Total | 22<br>*0.11%* | 19,410<br>*99.89%* | 19,432 |

### C.1.2 U.S. and State Manure Management Regulations

As a part of the Reserve's protocol management, regulatory developments are tracked through, among other outreach and research activities, reporting on regulatory requirements by project developers and verification bodies in the verification process. Of the farms with an anaerobic digester that have participated in GHG offset projects documented in EPA's AgSTAR program, 65 have listed their projects under the Reserve's U.S. Livestock Project Protocol. Twenty-seven projects have been registered with the Reserve, i.e., successfully undergone the verification process. This includes projects in four of the five top dairy producing states, namely, California, Wisconsin, Texas and Idaho. In states where registered Reserve projects are located, no state or federal regulations have been found that would require the use of a BCS.

## C.2 Performance Standard Recommendation

The original SAIC report recommended that a performance standard apply to the control of methane emissions from dairy and swine livestock operations in the U.S. and California. In particular, the performance standard should be a technology-specific threshold that dairy or swine operators would meet. The recommended threshold would be the installation of a BCS (e.g. an anaerobic digester).

The report found that even under favorable conditions digesters were found on less than 1% of the dairies in California, which was found to be representative of the U.S. market; and that if a dairy operator chose to install a digester then the farmer would be managing waste in the 99$^{th}$ percentile. This constitutes above and beyond common practice. The report also found that the main barrier inhibiting the installation and use of digesters was cost. Cost studies performed by EPA's AgSTAR program and the California Electricity Commission indicated that significant subsidies and/or incentives were needed to encourage additional digester installations.

The Reserve adopted this performance standard recommendation based on the data available at the time of the SAIC report. While the number of anaerobic digesters has increased significantly, the market penetration of BCS technology remains quite low, especially among those farms which are not receiving revenues from GHG offset markets. Today a dairy operator who chooses to install a digester would be managing waste in the 98th percentile—a modest increase since the original analysis, but hardly a significant shift in common practice. Furthermore, cost continues to inhibit wider adoption of BCS technologies according to a recent EPA report on the status of anaerobic digester adoption.[49] In light of these facts, the Reserve will not alter the current performance standard, but will continue to monitor market developments in the future.

## C.3 Renewable Energy Credits and Other Revenue Opportunities for Biogas-to-Energy Projects

Along with carbon credits, there are opportunities for farms installing digesters to earn additional revenues from a variety of sources that support renewable energy generation. These include loans and grants for developing biogas-to-energy projects and the sale of Renewable Energy Certificates (RECs) for use in a renewable portfolio standard (RPS) or a renewable portfolio goal (RPG)[50].

When considering additionality and the ability to generate RECs and CRTs from a livestock project, it is important to remember that the REC and CRT are created by two different but related activities. The REC is awarded for generating renewable electricity from the biogas collected by the BCS, whereas the CRT is awarded for the climate benefit created by the conversion of $CH_4$ in the biogas into $CO_2$ through combustion of the biogas. Under this protocol, projects are not required to generate electricity with collected biogas or send it to a natural gas pipeline. Rather, they are only required to destroy the biogas. So while a project may generate renewable electricity with its biogas, renewable energy generation is not an activity required or credited under this protocol.

As there are a number of active RPS, RPG and voluntary REC programs nationwide, the availability of revenue from the sales of RECs is inherently represented in the data analyzed to set the performance standard. Since this analysis shows that the installation of a digester is not common practice at dairy and swine farms, the Reserve does not limit a project's ability to generate or sell RECs. Due to the numerous barriers to implementation of an anaerobic digester project, their success typically relies on a complex array of factors, including multiple incentive program. Renewable energy incentives alone have not significantly increased the natural market penetration of these projects.

When considering additionality and the availability of public dollars to support the development of biogas-to-energy projects, the Reserve has identified numerous state and local programs to support such projects through grants, loans and payments. Although the Reserve's performance standard tests do not require individual project assessments of financial viability or returns, they are designed to reflect these factors in determining which projects are additional. Even with the funds available, the installation of anaerobic digesters according to this protocol is still very rare. Thus, even if a project does receive a grant or loan to support the generation of renewable

49 U.S. Anaerobic Digester Status Report, October 2010, http://www.epa.gov/agstar/documents/digester_status_report2010.pdf

50 Whereas compliance with an RPS is mandatory, RPGs set voluntary compliance targets.

energy from a biogas project, the performance standard and rules set forth in this protocol should ensure the additionality of the CRTs generated.

Beyond grants and loans for biogas-to-energy projects, there are two nationwide payment programs administered by USDA Natural Resource Conservation Service (NRCS) that support the installation of anaerobic digesters. Authorized by the 2008 Farm Bill, the Environmental Quality Incentives Program (EQIP), and the Chesapeake Bay Watershed Initiative (CBWI) are programs that provide payments to support the installation of a BCS and are implemented at the state- and county-level. NRCS expressly allows the sale of environmental credits from enrolled lands,[51] but does not provide any additional guidance on ensuring the environmental benefit of any mitigation payment stacked with an NRCS payment.

All NRCS programs share a common set of conservation practice standards that contain information on why and where the practice is to be applied, and set forth the minimum quality criteria that must be met during the application of that practice in order for it to achieve its intended purpose(s).

NRCS Conservation Practice Standard 366 – *Anaerobic Digester* (CPS 366) provides assistance to farmers for the treatment of manure and other byproducts of animal agricultural operations for one or more of the following reasons: to capture biogas for energy production, to manage odors, to reduce the net effect of greenhouse gas emissions, or to reduce pathogens.[52]

Data obtained from NRCS show that less than 0.3% of farms eligible for funding under CPS 366 (i.e., farms with anaerobic operations) have received NRCS funds to install a BCS.[53] In practice, only 9% of the farms that installed BCS since 2004 have received NRCS funds. Because the installation of anaerobic digesters is expensive, uncommon and generally not already funded by NRCS programs, the use of NRCS payments to help finance project activity is allowed under this protocol.

[51] EQIP, 7 CFR §1466.36; CSP, 7 CFR §1470.37.
[52] Natural Resources Conservation Service. (September 2009). Conservation Practice Standard, Anaerobic Digester, Code 366. State-specific conservation practice standards can be downloaded from http://efotg.sc.egov.usda.gov//efotg_locator.aspx.
[53] Based on 2004-2011 data obtained from NRCS Resource Economics, Analysis and Policy Division through personal communication.

# Appendix D Data Substitution

This appendix provides guidance on calculating emission reductions when data integrity has been compromised either due to missing data points or a failed calibration. No data substitution is permissible for the operational status of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters. If operational data are missing for a destruction device, then the device shall be assumed to have been inoperable, and will be assigned a destruction efficiency of zero for that period.

## D.1 Missing Data

The Reserve expects that projects will have continuous, uninterrupted data for the entire verification period. However, the Reserve recognizes that unexpected events or occurrences may result in brief data gaps.

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. Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data are missing for both parameters, no reductions can be credited.

Further, substitution may only occur when the following is true:

1. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
2. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

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 maybe applied:

| Duration of Missing Data | Substitution Methodology |
|---|---|
| Less than six hours | Use the average of the four hours immediately before and following the outage |
| Six to 24 hours | Use the 90% lower or upper confidence limit of the 24 hours prior to and after the outage, whichever results in greater conservativeness |
| One to seven days | Use the 95% lower or upper confidence limit of the 72 hours prior to and after the outage, whichever results in greater conservativeness |
| Greater than one week | No data may be substituted and no credits may be generated |

Note: It is conservative to use the upper confidence limit when calculating emissions from the BCS (Equation 5.6); however it is conservative to use the lower confidence limit when calculating the total amount of methane that is destroyed in the BCS Equation 5.10.

For periods when it is not possible to use data substitution to fill data gaps, no emission reductions may be claimed. The methane flow volume for these days shall be zero, and the number of reporting days for that month shall be reduced to exclude the days of missing data. This guidance is not to be used for venting events.

# Appendix E Development of the $B_0$ Sampling and Analysis Methodology

With the release of Livestock Protocol Version 4.0, the Reserve has adopted a novel methodology for the sampling and analysis of livestock manure to determine maximum methane potential. In all previous versions of the protocol, the value of this term was defined by the default options provided in Table B.3, which were themselves sourced from the EPA Climate Leaders Draft Manure Offset Protocol. Other than a change in the value of the default for Dairy Cows with Version 2.1 from a “low roughage” value to a “high roughage” value, these default values have not changed since the first version of the protocol was adopted. Reserve staff have received feedback from stakeholders that in many cases, the default value for a particular animal category, especially Dairy Cows, is excessively conservative. Based on this feedback, the Reserve initiated a process to explore the options for updating the default values for maximum methane potential ($B_0$). After review of existing methodologies and literature related to manure methane potential, the Reserve determined that there is currently not a clear basis for establishing different default values. However, direct sampling and analysis were identified as an option that could be immediately provided as an alternative to the existing default values.

In 2009 the Reserve adopted the Organic Waste Digestion project protocol (updated to Version 2.0 in 2011). This protocol introduced a procedure for the determination of site-specific $B_0$ value for organic wastewater streams (OWD V2.0, Section 6.1.3.2). These requirements formed the basis for the development of a sampling and analysis procedure for livestock projects.

In early September, 2012, the Reserve solicited stakeholder interest for participation in the development process for this new methodology. A diverse group of 36 stakeholders representing carbon project developers, academia, government, livestock industry, GHG verification bodies, and others, responded to this request. These stakeholders then received a memorandum detailing the proposed methodology and were invited to a webinar on September 19, 2012 to provide feedback and engage in discussion. 22 individuals participated in the webinar discussion, providing a great deal of feedback and suggestions for improvement.

In addition to the public stakeholder consultation, Reserve staff worked directly with experts in industry and academia to further refine the methodology. The goal was to identify a sampling and testing regime that could consistently provide accurate estimates of the $B_0$ value of different manure streams, and that would be reasonably practical for implementation. The major considerations and decisions are addressed below.

### Sampling Schedule

The sampling procedure requires that six samples be taken at regular intervals throughout the day. These individual samples are then combined into one composite sample to represent that event. The sampling procedure in the OWD protocol calls for 10 samples spaced out over at least one week. In consultation with expert stakeholders, it was determined that livestock manure will be less variable over such short timescales, and that the collection of multiple samples in a single day would be sufficient to control for sample variability and error. A more onerous sampling requirement would introduce additional resourcing requirements and costs disproportionate to any reduction in uncertainty/error.

The procedure also requires that the sampling event take place between the months of August through November (inclusive). The Reserve has limited the applicability of this procedure to dairy facilities, and expects that it will mainly be used for the determination of a site-specific $B_0$

for dairy cows. Thus, the timing of the sampling procedure is designed to avoid overestimating the $B_0$ value for this particular livestock category. Academic experts advised the Reserve that the methane generating potential of dairy cow manure tends to be positively correlated with milk production.[54] To ensure that the average $B_0$ value for the year is not overestimated, it is appropriate to avoid sampling the manure during periods of above-average milk production. Reserve staff used data from the National Agricultural Statistics Service[55] to examine monthly milk production trends. For the years 1998-2011, the milk production for each month (in lb/head) was compared to the average monthly milk production for that year. This process highlighted the months with above or below-average milk production, while controlling for the overall trend of increasing milk production year-over-year. Figure E.1 shows the results of this analysis and the consistent pattern of milk production during this 14 year period.

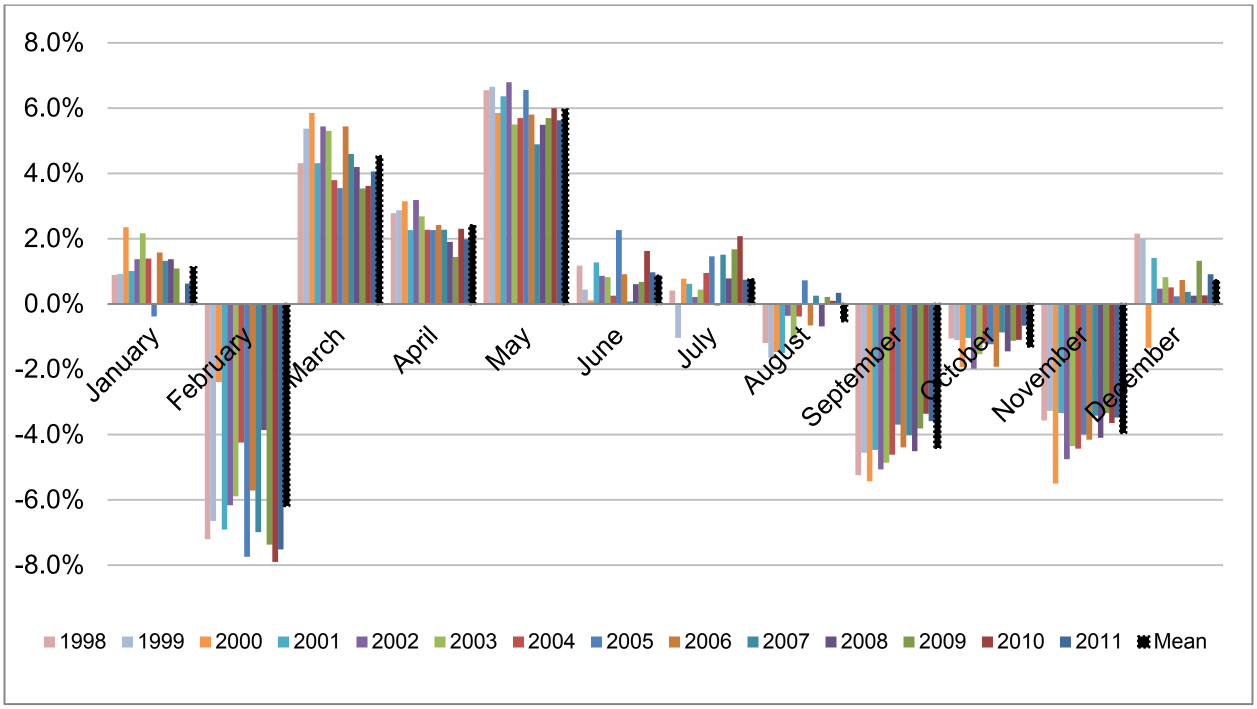



**Figure E.1.** Monthly Milk Production Trends as a Percent Change Over Annual Average Monthly Milk Production (1998-2011)

Based on this analysis the Reserve has limited the sampling period to August through November. These months consistently exhibit average- to below-average milk production, which should result in a conservative estimate of the annual average $B_0$ value.

### Sample Source

The procedure instructs the user to obtain a manure sample that represents only a single animal category, prior to mixing with other residues (except for flush water in the case of flush systems). While certain stakeholders indicated through public comment that they would prefer to sample the entire waste stream as it enters the digester, there are two main reasons why this requirement was not amended:

[54] In the future, it may be possible to develop a default methane potential that is based directly on monthly milk production, though additional research is needed.
[55] Accessed from the USDA website at http://quickstats.nass.usda.gov/.

1. The waste stream entering the digester may contain ineligible materials which, while permitted to be processed by the project BCS, should not be represented in the quantification of baseline emissions.
2. The baseline quantification model is run on a monthly basis, using the actual animal population figures for that month. The relative populations of different animal categories may change during the year, resulting in an overall $B_0$ value for the manure from that facility that is variable through time. To use a composite $B_0$ value, representative of multiple animal categories, would create quantification inaccuracies if relative populations change from one month to the next (see Table E.1).

**Table E.1.** Effects of Relative Population Size on Composite $B_0$ Value

| Animal Category | $B_0$ Value | Population in Month 1 | Population in Month 2 | Population in Month 3 |
|---|---|---|---|---|
| Dairy Cows | 0.24 | 2,000 | 800 | 3,000 |
| Heifers | 0.17 | 500 | 2,000 | 200 |
| Calves | 0.17 | 500 | 1,200 | 0 |
| | ***Composite $B_0$ Value*** | ***0.22*** | ***0.18*** | ***0.24*** |

There is an additional step for dairies that utilize a flush system for manure management, as the flush water is typically composed of some type of wastewater, which could have a significant methane potential. For these systems it is necessary to also sample the flush water inlet point prior to mixing with the manure, so that the methane potential of the flush water can then be subtracted from the methane potential of the sample.

### Laboratory Analysis

The Reserve undertook research to determine whether standard procedures/processes existed for the professional analysis of $B_0$ potential. This research revealed that while there is currently no standard laboratory certification scheme within the US pertaining to this type of analysis, there are commonly-accepted methods for undertaking the relevant biochemical methane potential (BMP) analysis itself. The requirements to document a laboratory's experience and standard operating procedures were introduced to ensure rigor and consistency among testing bodies.

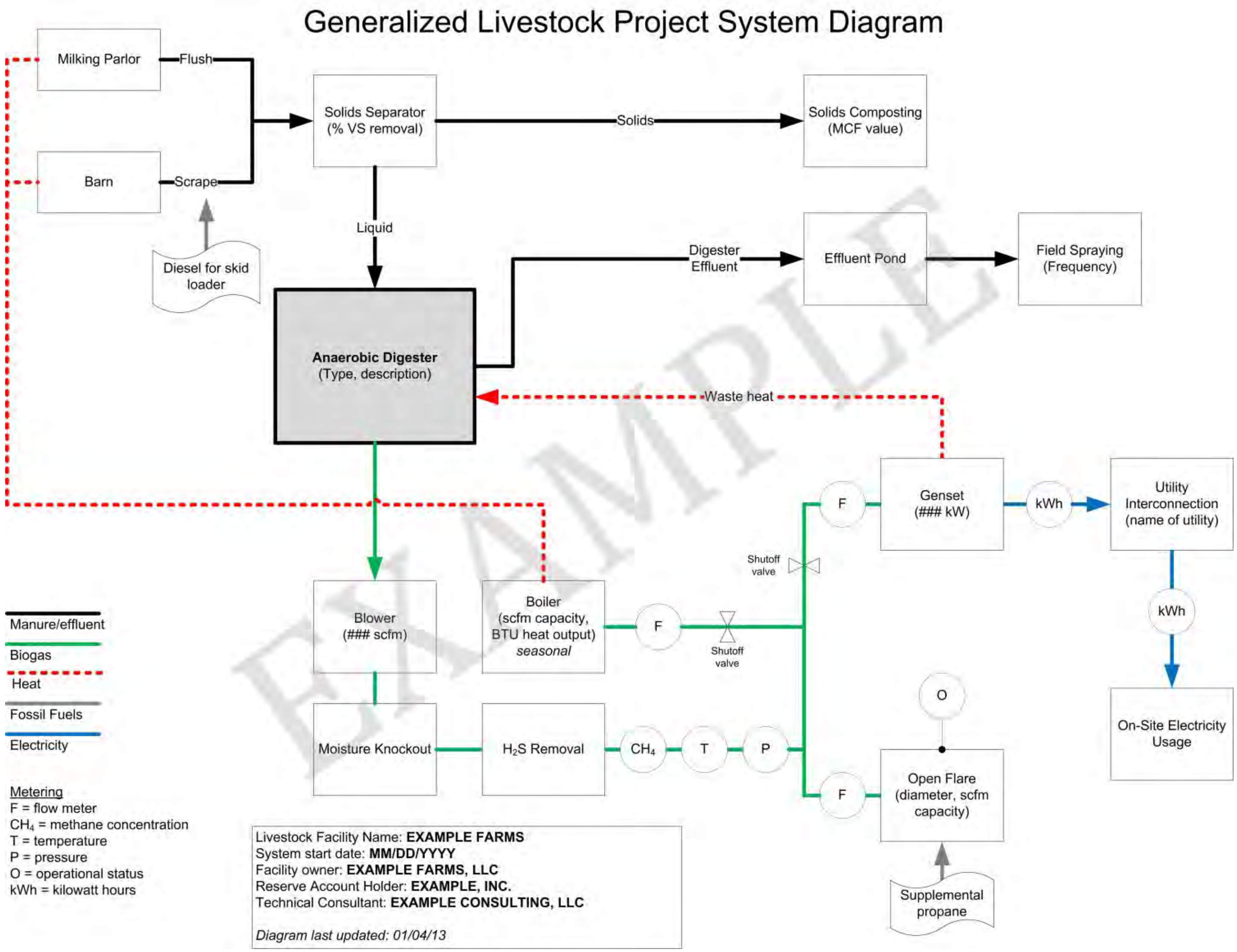
The Reserve consulted with commercial and university testing laboratories regarding the requirements for the biochemical methane potential (BMP) assay. The resulting requirements closely resemble the standard procedures of existing laboratories. It is necessary for the protocol to prescribe at least basic parameters for the BMP assay in order to ensure consistency among projects that hire different laboratories. The inclusion of a control assay was suggested by multiple laboratories as an important quality check on the viability of the seed inoculum that is used for the BMP assay.

**Stakeholder Participation**

The Reserve would like to thank the following stakeholders, in addition to others not listed here, for their participation in the research and development of this methodology.

| | |
|---|---|
| David Belcher | Camco |
| Michael Carim | First Environment, Inc. |
| Dr. Craig Frear | Washington State University |
| Noel Gurwick | Smithsonian Environmental Research Center |
| Karen Haugen-Kozyra | The Prasino Group |
| Cortney Itle | Eastern Research Group, Inc. |
| Dr. Xiaomei Li | XY Green Carbon |
| Dr. John H. Martin, Jr. | Hall Associates |
| Carl Morris | Joseph Gallo Farms |
| Dr. Scott Subler | Environmental Credit Corp. |
| Peter Weisberg | The Climate Trust |

# Appendix F Sample Livestock Project Diagram



California Environmental Protection Agency

**AIR RESOURCES BOARD**

# Compliance Offset Protocol Livestock Projects

## Capturing and Destroying Methane from Manure Management Systems

Adopted: November 14, 2014

Note: *All text is new. As permitted by title 2, California Code of Regulations, section 8, for ease of review, underline to indicate adoption has been omitted.*

**(This page left intentionally blank)**

**Table of Contents**

## Contents

## Chapter 1. Purpose and Definitions

### 1.1. Purpose

(a) The purpose of the Compliance Offset Protocol Livestock Projects (protocol) is to quantify greenhouse gas emission reductions associated with the installation of a BCS for manure management on dairy cattle and swine farms that would otherwise be vented into the atmosphere as a result of livestock operations from those farms.

(b) AB 32 exempts quantification methodologies from the Administrative Procedure Act[1]; however, those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process. Those sections that are considered to be a quantification methodology are clearly indicated in the title of the chapter or subchapter if only a portion of that chapter is considered part of the quantification methodology of the protocol.

### 1.2. Definitions

(a) For the purposes of this protocol, the following definitions apply:

(1) "Aerobic Treatment" means the biological oxidation of manure collected as a liquid with either forced or natural aeration. Natural aeration is limited to aerobic and facultative ponds and wetland systems and is due primarily to photosynthesis. Hence, these systems typically become anoxic during periods without sunlight.

(2) "Anaerobic" means pertaining to or caused by the absence of oxygen.

(3) "Anaerobic Digester" or "Digester" means a large containment vessel or covered lagoon that collects and anaerobically digests animal excreta with or without straw. Digesters are designed and operated for waste

[1] Health and Safety Code section 38571

stabilization by the microbial reduction of complex organic compounds to $CO_2$ and $CH_4$, which is captured and flared or used as a fuel.

(4) “Baseline Emissions,” see “Project Baseline Emissions”

(5) “Biogas Control System” or “BCS” commonly referred to as a digester, is a system that is designed to capture and destroy the biogas that is produced by the anaerobic treatment and/or storage of livestock manure and/or other organic material.

(6) “Biogenic $CO_2$ Emissions,” for the purposes of this protocol, means $CO_2$ emissions resulting from the combustion and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the carbon cycle, as opposed to anthropogenic emissions.

(7) “Burned for Fuel” means the dung and urine that are excreted on fields. The sun dried dung cakes are burned for fuel.

(8) “Cap-and-Trade Regulation” or “Regulation” means ARB’s regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(9) “Cattle and Swine Deep Bedding” means that as manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system is also known as a “bedded pack manure” management system and may be combined with a dry lot or pasture.

(10) “Centralized Digester” means a digester that integrates waste from more than one livestock operation.

(11) “Composting – Intensive Windrow” means composting in windrows with regular (at least daily) turning for mixing and aeration.

(12) “Composting – In-Vessel” means composting, typically in an enclosed channel, with forced aeration and continuous mixing.

(13) “Composting – Passive Windrow” means composting in windrows with infrequent turning for mixing and aeration.

(14) “Composting – Static Pile” means composting in piles with forced aeration but no mixing.

(15) “Daily Spread” means manure that is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.

(16) “Dry Lot” means a paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.

(17) “Emission Factor” has the same definition as provided in section 95102 of the Mandatory Reporting Regulation.

(18) “Enclosed Vessel” means a complete mix, fixed film, or plug-flow digester that is topped by a cover (e.g. hardened or dual membrane flexible) that provides a complete enclosure to the digester itself. A digester cover design that does not meet this exact definition must offer verifiable proof that it achieves the same biogas capture efficiency as an enclosed vessel cover would.

(19) “Flare” has the same definition as provided in section 95102 of the Mandatory Reporting Regulation.

(20) “Greenfield Livestock Project” means a project that is implemented at a new livestock facility that has no prior manure management system.

(21) “Initial Start-up Period” means the period between post-system installation and pre-project commencement. After the installation of the project’s BCS, the Offset Project Operator or Authorized Project Designee may run, tune, and test the system to ensure its operational quality.

(22) “Liquid Slurry” means manure that is stored as excreted or with some minimal addition of water in either tanks or earthen ponds outside the animal housing, usually for periods of less than one year.

(23) “Livestock Project” means installation of a BCS that, in operation, causes a decrease in GHG emissions from the baseline scenario through destruction of the methane component of biogas.

(24) “Mandatory Reporting Regulation” or “MRR” means ARB’s regulation establishing the Mandatory Reporting of Greenhouse Gas Emissions set

forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 2 (commencing with section 95100).

(25) "Mobile Combustion" means emissions from the transportation of materials, products, waste, and employees that result from the combustion of fuels in company owned or controlled mobile combustion sources.

(26) "Pasture/Range/Paddock" means that the manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.

(27) "Pit Storage Below Animal Confinements" means the collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility, usually for periods of less than one year.

(28) "Project Baseline Emissions" or "Baseline Emissions" means the GHG emissions within the Offset Project Boundary that would have occurred if not for the installation of the BCS.

(29) "Registry offset credits" means the offset credits defined in section 95802 of the Regulation and whose issuance is described in section 95980 and section 95980.1 of the Regulation.

(30) "Solid Storage" means the storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked because there is a sufficient amount of bedding material or loss of moisture by evaporation.

(31) "Standard Conditions" or "Standard Temperature and Pressure" or "STP" means, for the purposes of this protocol, 60 degrees Fahrenheit and 14.7 pounds per square inch absolute.

(32) "Standard Cubic Foot" or "scf" means, for the purposes of this protocol, a measure of quantity of gas equal to a cubic foot of volume at 60 degrees Fahrenheit and 14.7 pounds per square inch (1atm) pressure.

(33) "Stationary Combustion Source" means a stationary source of emissions from the production of electricity, heat, or steam that result from the combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.

(34) "Uncovered Anaerobic Lagoon" means a type of liquid storage system that is designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage, depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields.

(35) "Van't Hoff-Arrhenius Factor" means the proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system.

(b) For terms not defined in subchapter 1.2(a) of this protocol, the definitions in section 95802 of the Regulation apply.

(c) Acronyms. For purposes of this protocol, the following acronyms apply:

(1) "AB 32" means The Global Warming Solutions Act of 2006.

(2) "APA" means Administrative Procedure Act.

(3) "ARB" means California Air Resources Board.

(4) "BCS" means biogas control system.

(5) "BDE" means biogas destruction efficiency.

(6) "$CH_4$" means methane.

(7) "CITSS" means Compliance Instrument Tracking System Service.

(8) "CNG" means condensed natural gas.

(9) "$CO_2$" means carbon dioxide.

(10) "GHG" means greenhouse gas.

(11) "GWP" means global warming potential.

(12) "ID" means identification.

(13) "IPCC" means Intergovernmental Panel on Climate Change.

(14) "kg" means kilogram.

(15) "lb" means pound.

(16) "LNG" means liquefied natural gas.

(17) "MMBtu" means one million British thermal units.

(18) "MS" means management system.

(19) “mt” means metric ton.

(20) “$N_2O$” means nitrous oxide.

(21) “NG” means natural gas.

(22) “QA/QC” means quality assurance/quality control.

(23) “R” mean Rankine.

(24) “scf” means standard cubic feet.

(25) “SSR” means GHG sources, GHG sinks, and GHG reservoirs.

(26) “STP” means standard temperature and pressure.

(27) “TAM” means typical average mass.

(28) “VS” means volatile solids.

## Chapter 2. Eligible Activities – Quantification Methodology

This protocol defines a set of activities designed to reduce GHG emissions that result from anaerobic manure treatment at dairy cattle and swine farms. Projects that install a BCS that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations are eligible.

### 2.1. Project Definition

(a) The BCS must destroy methane gas that would otherwise have been emitted to the atmosphere in the absence of the offset project from uncontrolled anaerobic treatment and/or storage of manure.

(b) Captured biogas can be destroyed on-site, transported for off-site use (e.g. through gas distribution or transmission pipeline), or used to power vehicles.

(c) A centralized digester that integrates waste from more than one livestock operation meets the definition of an offset project.

## Chapter 3. Eligibility

In addition to the offset project eligibility criteria and the regulatory program requirements set forth in subarticle 13 of the Regulation, livestock offset projects must adhere to the eligibility requirements below:

### 3.1. General Eligibility Requirements.

(a) Offset projects that use this protocol must:

(1) Involve the installation and operation of a device, or set of devices, associated with the capture and destruction of methane;
(2) Capture methane that would otherwise be emitted to the atmosphere; and
(3) Destroy the captured methane through an eligible end-use management option per subchapter 3.4 of this protocol.

(b) Offset Project Operators or, if applicable, Authorized Project Designees using this protocol must:
(1) Provide the listing information required by section 95975 of the Regulation and subchapter 7.1 of this protocol;
(2) Monitor GHG emission SSRs within the GHG assessment boundary as delineated in chapter 4 pursuant to the requirements of Chapter 6 of this protocol;
(3) Quantify GHG emission reductions pursuant to Chapter 5 of this protocol;
(4) Prepare and submit the Offset Project Data Report for each reporting period that include the information requirements in chapter 7 of this protocol; and
(5) Obtain offset verification services from an ARB-accredited offset verification body in accordance with section 95977 of the Regulation and Chapter 8 of this protocol.

### 3.2. Location

(a) Only projects located in the United States and United States' territories are eligible under this protocol.

(b) Offset projects situated on the following categories of land are only eligible under this protocol if they meet the requirements of this protocol and the Regulation, including the waiver of sovereign immunity requirements of section 95975(l) of the Regulation:
(1) Land that is owned by, or subject to an ownership or possessory interest of a Tribe;
(2) Land that is "Indian lands" of a Tribe, as defined by 25 U.S.C. §81(a)(1); or
(3) Land that is owned by any person, entity, or Tribe, within the external borders of such Indian lands.

### 3.3. The Offset Project Operator or Authorized Project Designee

(a) The Offset Project Operator or Authorized Project Designee is responsible for project listing, monitoring, reporting, and verification.

(b) The Offset Project Operator or Authorized Project Designee must submit the information required by subarticle 13 of the Regulation and in subchapters 7.1 and 7.2 of this protocol.

(c) The Offset Project Operator must have legal authority to implement the offset project.

### 3.4. Additionality

Offset projects must meet the additionality requirements of section 95973(a)(2) of the Regulation, as well as the requirements in this protocol. 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 in subchapter 3.4.1. and the Performance Standard Evaluation in subchapter 3.4.2. of this protocol.

#### 3.4.1. Legal Requirement Test

(a) Emission reductions achieved by a livestock project must exceed those required by any law, regulation, or legally binding mandate, as required by sections 95973(a)(2)(A) and 95975(n) of the Regulation.

(b) The following legal requirement test applies to all livestock projects:

   (1) If no law, regulation, or legally binding mandate requiring the destruction of methane at which the project is located exists, all emission reductions resulting from the capture and destruction of methane are considered to not be legally required, and therefore eligible for crediting under this protocol.

   (2) If any law, regulation, or legally binding mandate requiring the destruction of methane at which the project is located exists, only emission reductions resulting from the capture and destruction of methane 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.

### 3.4.2. Performance Standard Evaluation

(a) Emission reductions achieved by a livestock project must exceed those likely to occur in a conservative business-as-usual scenario.

(b) The performance standard evaluation for existing farms is satisfied if the depth of the anaerobic lagoons or ponds prior to the offset project's commencement were sufficient to prevent algal oxygen production and create an oxygen-free bottom layer; which means at least 1 meter in depth at the shallowest area.

(c) The performance standard evaluation for a greenfield livestock project is satisfied only if uncontrolled anaerobic storage and/or treatment of manure is common practice in the industry and geographic region where the offset project is located as determined by ARB. Greenfield projects must use the baseline assumptions in Table A.10.

## 3.5. Offset Project Commencement

(a) For this protocol, offset project commencement is defined as the date at which the offset project's BCS becomes operational.

(b) A BCS is considered operational on the date at which the system begins producing and destroying methane gas upon completion of an initial start-up period. An initial start-up period must not exceed nine months. The commencement date, which follows the initial start-up period, is defined as the date that the BCS becomes operational.

(c) Pursuant to section 95973(a)(2)(B) of the Regulation, compliance offset projects must have an offset project commencement date after December 31, 2006.

## 3.6. Offset Project Crediting Period

(a) For this protocol, the crediting period for an eligible project is ten reporting periods from the first day of the first reporting period as identified in the first verified Offset Project Data Report received by ARB or an Offset Project Registry approved pursuant to section 95986 of the Regulation.

(b) The upgrade of a BCS at an existing project continues the original crediting period and retains the original baseline scenario.

(c) Switching manure from an existing project to a different BCS, including a centralized BCS, continues the crediting period of the project with the earliest commencement date. For a centralized BCS, only livestock manure that meets the relevant eligibility requirements of chapter 3 of this protocol is eligible for crediting under this protocol.

### 3.7. Regulatory Compliance

An offset project must meet the regulatory compliance requirements set forth in section 95973(b) of the Regulation.

## Chapter 4. Offset Project Boundary – Quantification Methodology

The GHG assessment boundary, or 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 methane. The following apply to all livestock projects regarding offset project boundaries:

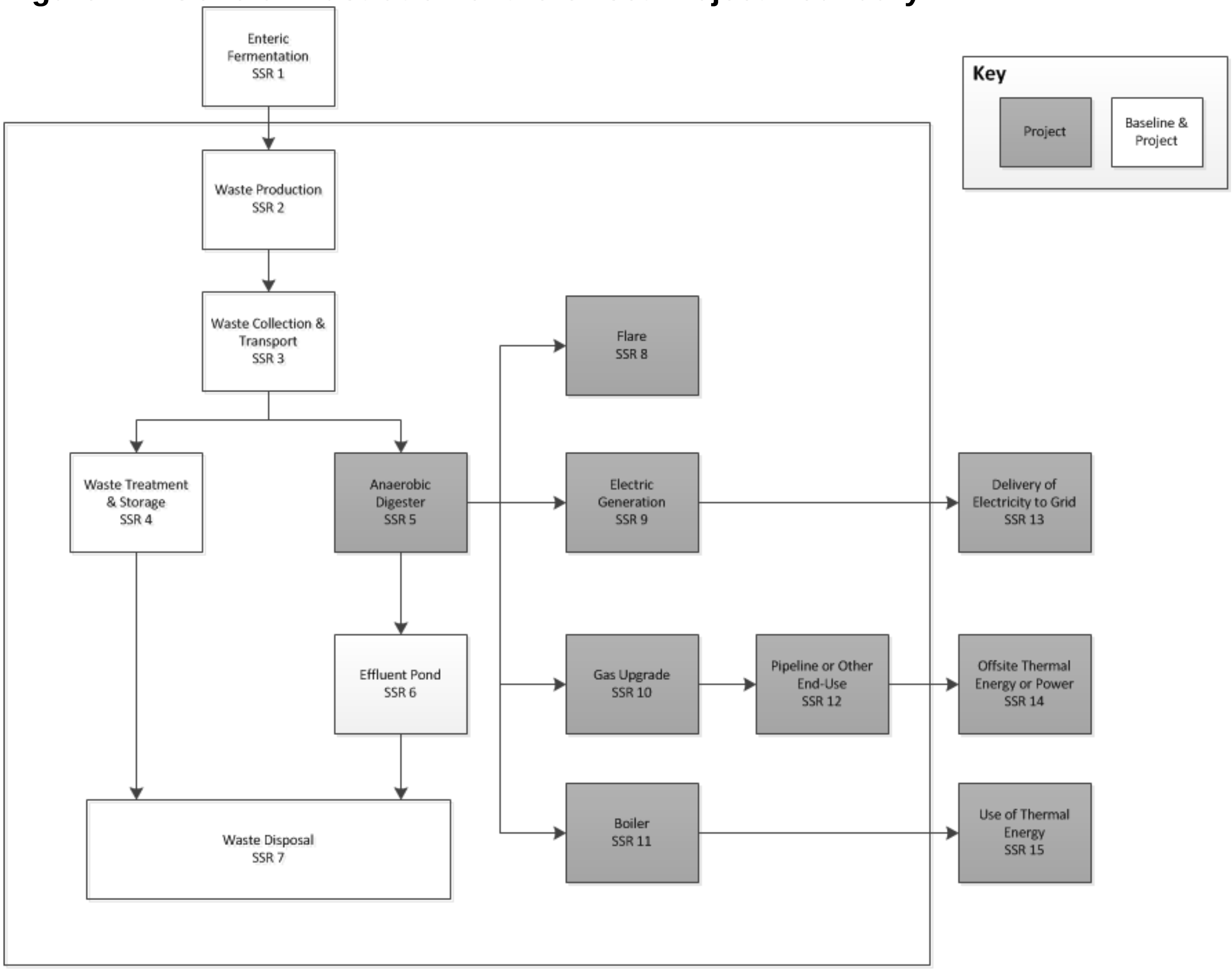
(a) Figure 4.1 illustrates the GHG assessment boundary for livestock projects, indicating which SSRs are included or excluded from the Offset Project Boundary.

  (1) All SSRs within the bold line are included and must be accounted for under this protocol.

  (2) SSRs in unshaded boxes are relevant to the baseline and project emissions.

  (3) SSRs in shaded boxes are relevant only to the project emissions.

**Figure 4.1. General Illustration of the Offset Project Boundary**




(b) Table 4.1. Description of all GHG Sources, GHG Sinks, and GHG Reservoirslists the SSRs for livestock projects, indicating which gases are included or excluded from the offset project boundary.

**Table 4.1. Description of all GHG Sources, GHG Sinks, and GHG Reservoirs**

| SSR | GHG Source | GHG | Relevant to Baseline (B) or Project (P) | Included/ Excluded |
|---|---|---|---|---|
| 1 | Emissions from enteric fermentation | $CH_4$ | B, P | Excluded |
| 2 | Emissions from waste deposits in barn, milking parlor, or pasture/corral | $N_2O$ | B, P | Excluded |
| | Emissions from mobile and stationary support equipment | $CO_2$ | B, P | Included |
| | | $CH_4$ | | Excluded |
| | | $N_2O$ | | Excluded |

| SSR | GHG Source | GHG | Relevant to Baseline (B) or Project (P) | Included/ Excluded |
|---|---|---|---|---|
| 3 | Emissions from mechanical systems used to collect and transport waste (e.g. engines and pumps for flush systems; vacuums and tractors for scrape systems) | $CO_2$ | B, P | Included |
| | | $CH_4$ | | Excluded |
| | | $N_2O$ | | Excluded |
| | Vehicle emissions (e.g. for centralized digesters) | $CO_2$ | | Included |
| | | $CH_4$ | | Excluded |
| | | $N_2O$ | | Excluded |
| 4 | Emissions from waste treatment and storage including: anaerobic lagoons, dry lot deposits, compost piles, solid storage piles, manure settling basins, aerobic treatment, storage ponds, etc. | $CO_2$ | B, P | Excluded |
| | | $CH_4$ | | Included |
| | | $N_2O$ | | Excluded |
| | Emissions from support equipment | $CO_2$ | | Included |
| | | $CH_4$ | | Excluded |
| | | $N_2O$ | | Excluded |
| 5 | Emissions from the anaerobic digester due to biogas collection inefficiencies and venting events | $CH_4$ | P | Included |
| 6 | Emissions from the effluent pond | $CH_4$ | B, P | Included |
| | | $N_2O$ | | Excluded |
| 7 | Emissions from land application | $N_2O$ | B, P | Excluded |
| | Vehicle emissions for land application and/or off-site transport | $CO_2$ | B, P | Included |
| | | $CH_4$ | | Excluded |
| | | $N_2O$ | | Excluded |
| 8 | Emissions from combustion during flaring, including emissions from incomplete combustion of biogas | $CO_2$ | P | Excluded |
| | | $CH_4$ | | Included |
| | | $N_2O$ | | Excluded |
| 9 | Emissions from combustion during electric generation, including incomplete combustion of biogas | $CO_2$ | P | Excluded |
| | | $CH_4$ | | Included |
| | | $N_2O$ | | Excluded |
| 10 | Emissions from equipment upgrading biogas for pipeline injection or use as CNG/LNG fuel | $CO_2$ | P | Included |
| | | $CH_4$ | | Excluded |
| | | $N_2O$ | | Excluded |
| 11 | Emissions from combustion at boiler including emissions from incomplete combustion of biogas | $CO_2$ | P | Excluded |
| | | $CH_4$ | | Included |
| | | $N_2O$ | | Excluded |
| 12 | Emissions from combustion of biogas by end user of pipeline or CNG/LNG, including incomplete combustion | $CO_2$ | P | Excluded |
| | | $CH_4$ | | Included |
| | | $N_2O$ | | Excluded |

| SSR | GHG Source | GHG | Relevant to Baseline (B) or Project (P) | Included/ Excluded |
|---|---|---|---|---|
| 13 | Delivery and use of project electricity to grid | $CO_2$<br>$CH_4$<br>$N_2O$ | P | Excluded |
| 14 | Off-site thermal energy or power | $CO_2$<br>$CH_4$<br>$N_2O$ | P | Excluded |
| 15 | Use of project-generated thermal energy | $CO_2$<br>$CH_4$<br>$N_2O$ | P | Excluded |
| 16 | Project construction and decommissioning emissions | $CO_2$<br>$CH_4$<br>$N_2O$ | P | Excluded |

## Chapter 5. Quantifying GHG Emission Reductions – Quantification Methodology

(a) GHG emission reductions from a livestock project are quantified by comparing actual project emissions to baseline emissions within the offset project boundary.

(b) The Offset Project Operator or, if applicable, Authorized Project Designee must use the specific calculation methods provided in this protocol to determine baseline and project GHG emissions.

(c) GHG emission reductions must be quantified over an entire reporting period. Pursuant to section 95802(a) of the Regulation, the initial reporting may consist of 6 to 24 consecutive months, and all subsequent reporting periods consist of 12 consecutive months.

(d) Measurements used to quantify emission reductions must be corrected to standard conditions of 60°F and 14.7 pounds per square inch (1 atm).

(e) Global warming potential values must be determined consistent with the definition of Carbon Dioxide Equivalent in MRR section 95102(a).

(f) GHG emission reductions for a reporting period (ER) must be quantified using Equation 5.1 by summing two selections:

(1) The smaller of:

(A) the project methane emission ($PE_{CH4}$) subtracted from modeled project baseline methane emissions ($BE_{CH4\ Mod}$); or

(B) the metered and destroyed methane ($CH_{4\ meter}$); and

(2) The smaller of:

(A) project carbon dioxide emissions ($PE_{CO2}$) subtracted from the project baseline carbon dioxide emissions ($BE_{CO2}$); or

(B) zero.

**Equation 5.1: GHG Reductions from Installing a BCS**

$$ER = MIN[(BE_{CH4\ Mod}-PE_{CH4}),CH_{4\ meter}] + MIN[(BE_{CO2}-PE_{CO2}),0]$$

| *Where,* | | | Units |
|---|---|---|---|
| $BE_{CH4\ Mod}$ | = | Modeled baseline methane emissions during the reporting period | $mtCO_2e$ |
| $PE_{CH4}$ | = | Total project methane emissions during the reporting period | $mtCO_2e$ |
| $CH_{4\ meter}$ | = | Aggregated quantity of methane collected and destroyed during the reporting period | $mtCO_2e$ |
| $BE_{CO2}$ | = | Total baseline anthropogenic $CO_2$ emissions from electricity consumption and mobile and stationary combustion that would have occurred in the absence of the project | $mtCO_2e$ |
| $PE_{CO2}$ | = | Total project anthropogenic $CO_2$ emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity | mtCO2e |

### 5.1. Quantifying Baseline Methane Emissions

(a) Total modeled project baseline methane emissions for a reporting period ($BE_{CH4\ Mod}$) must be estimated by using equation 5.2 and summing the baseline methane emissions for all SSRs which table 4.1 identifies as included within the project boundary.

(b) Baseline emissions represent the GHG emission that would have occurred in the absence of the BCS. Baseline emissions are calculated based on the manure management system in place prior to the installation of the BCS. Baseline emissions are recalculated for each reporting period and represent the emissions that would have occurred with the previous manure management system operated under the current conditions.

**Equation 5.2: Modeled Project Baseline Methane Emissions**

$$BE_{CH4Mod} = \sum_{AS} BE_{CH4,AS} + \sum_{non-AS} BE_{CH4,non-AS}$$

| *Where,* | | | Units |
|---|---|---|---|
| $BE_{CH4}$ | = | Total project baseline methane emissions for a reporting period. | $mtCO_2e$ |
| $BE_{CH4,AS}$ | = | Total project baseline methane emissions from anaerobic storage/treatment systems by livestock category for a reporting period | $mtCO_2e$ |
| $BE_{CH4,non-AS}$ | = | Total project baseline methane emissions from non-anaerobic storage/treatment systems by livestock category for a reporting period | $mtCO_2e$ |
| AS | = | Anaerobic storage/treatment systems | |
| Non-AS | = | Non-anaerobic storage/treatment systems | |

(c) Baseline modeled methane emission from anaerobic storage/treatment systems ($BE_{CH4,AS,L}$) must be quantified using equation 5.3.

(d) Methane producing capacity for each livestock category ($B_{O,L}$) and volatile solids produced ($VS_{table}$) must use default values from tables A.2 and A.4 as applicable.

(e) The average monthly population for each livestock category ($P_{L,i}$) must use site-specific data monitored and recorded at least monthly.

(f) The fraction of volatile solids ($MS_{AS,L}$) sent to each anaerobic storage/treatment system for each livestock category represents the percent of manure that would be sent to (managed by) the anaerobic manure storage/treatment systems, taking into account any volatile solids removed by solid separation equipment, in the project baseline case, as if the BCS was never installed. Site-specific data must be used if available. If site-specific data is unavailable, values from table A.9 can be used to calculate $MS_{AS,L}$.

(g) The number of reporting days in the reporting month ($RD_{rm,i}$) must be calculated by subtracting the number of days not in the reporting period for the reporting month and the number of days the project is ineligible to report from the total number of reporting days in the reporting month. Ineligible days include, but are not limited to, days with missing data beyond what is allowed to be substituted according to the methods in appendix B.

(h) The annual average live weight of the animals ($Mass_L$), per livestock category, must be taken from site-specific livestock mass data. If site-specific data are unavailable, Typical Average Mass (TAM) values from table A.1 must be used.

(i) The monthly average ambient temperature ($T_2$) in Kelvin must be obtained from the closest weather station, with available data, located in the same air basin, if applicable.

(j) If the volatile solids retention time in the anaerobic storage/treatment system is less than or equal to 30 days, then the volatile solids retained in the system from the previous month ($VS_{avail, AS, L, i-1} - VS_{deg,AS,L,i-1}$) must be set to zero.

(k) For the month following the complete drainage and cleaning of solid buildup from the anaerobic storage/treatment system, the volatile solids retained in the system from the previous month ($VS_{avail, AS, L, i-1} - VS_{deg,AS,L,i-1}$) must be set to zero.

**Equation 5.3: Modeled project baseline methane emissions from anaerobic storage treatment systems**

$$BE_{CH4,AS} = \sum_{L,i} (VS_{\deg,AS,L,i} \times B_{0,L}) \times 0.68 \times 0.001 \times GWP_{CH4}$$

| *Where,* | | | Units |
|---|---|---|---|
| $BE_{CH4,AS}$ | = | Total project baseline methane emissions from anaerobic manure storage/treatment systems for a reporting period | $mtCO_2e$ |
| $VS_{deg,AS,L,i}$ | = | Monthly volatile solids degraded in anaerobic manure storage/treatment system ‘AS’ from livestock category ‘L’ | kg dry matter |
| $B_{0,L}$ | = | Maximum methane producing capacity of manure for livestock category ‘L’ from table A.2 | $m^3$ $CH_4$/kg of VS |
| 0.68 | = | Density of methane (1 atm, 60°F) | $kg/m^3$ |
| 0.001 | = | Conversion factor from kg to mt | |
| $GWP_{CH4}$ | = | Global warming potential of methane | |
| L | = | Livestock category | |
| i | = | Months in the reporting period | |

With:

$$VS_{\deg,AS,L,i} = VS_{avail,AS,L,i} \times f$$

| *Where,* | | | Units |
|---|---|---|---|
| $VS_{deg,AS,L.i}$ | = | Monthly volatile solids degraded by anaerobic manure storage/ treatment system ‘AS’ by livestock category ‘L’ | kg dry matter |
| $VS_{avail,AS,L,i}$ | = | Monthly volatile solids available for degradation from anaerobic manure storage/treatment system ‘AS’ by livestock category ‘L’ | kg dry matter |
| f | = | Van’t Hoff-Arrhenius factor | |
| i | = | Months in the reporting period | |

And:

$$VS_{avail,AS,L,i} = \left(VS_L \times P_{L,i} \times MS_{AS,L} \times RD_{rm,i} \times 0.8\right) + \left(VS_{avail,AS,L,i-1} - VS_{\deg,AS,L,i-1}\right)$$

| *Where,* | | | Units |
|---|---|---|---|
| $VS_{avail,AS,L}$ | = | Monthly volatile solids available for degradation in anaerobic storage/treatment system 'AS' by livestock category 'L' | kg dry matter |
| $VS_L$ | = | Volatile solids produced by livestock category 'L' on a dry matter basis | kg/ animal/ day |
| $P_{L,i}$ | = | Monthly average population of livestock category 'L' | |
| $MS_{AS,L}$ | = | Fraction of volatile solids sent to (managed in) anaerobic manure storage/treatment system 'AS' from livestock category 'L' | Fraction (0-1) |
| $RD_{rm,i}$ | = | Number of reporting days in the reporting month | days |
| 0.8 | = | System calibration factor | |
| $VS_{avail-1,AS}$ | = | Previous month's volatile solids available for degradation in anaerobic system 'AS' | kg |
| $VS_{deg-1,AS}$ | = | Previous month's volatile solids degraded by anaerobic system 'AS' | kg |

And:

$$VS_L = VS_{table} \times \frac{Mass_L}{1000}$$

| *Where,* | | | Units |
|---|---|---|---|
| $VS_L$ | = | Volatile solid excretion on a dry matter weight basis | kg/ animal/ day |
| $VS_{table}$ | = | Volatile solid excretion from table A.2 or A.4 | kg/ day/ 1000kg |
| $Mass_L$ | = | Average live weight for livestock category 'L'; if site-specific data is unavailable, use values from table A.1 | kg |

And:

$$f = MIN\left(\exp\left[\frac{E\left(T_2 - T_1\right)}{RT_1T_2}\right], 0.95\right)$$

| *Where,* | | | Units |
|---|---|---|---|
| f | = | Van't Hoff-Arrhenius factor | |
| E | = | Activation energy constant (15,175) | cal/mol |
| $T_1$ | = | 303.16 | Kelvin |
| $T_2$ | = | Monthly average ambient temperature (K = °C + 273). If $T_2$ < 5 °C then *f* = 0.104. | Kelvin |
| R | = | Ideal gas constant (1.987) | cal/Kmol |

(l) Modeled baseline methane emissions from non-anaerobic storage/treatment systems ($BE_{CH4,non-AS,L}$) must be quantified using equation 5.4.

(m) The fraction of volatile solids ($MS_{non-AS,L}$) sent to each non-anaerobic storage/treatment system for each livestock category represents the fraction of manure that would be sent to (managed by) the non-anaerobic manure storage/treatment systems, taking into account any volatile solids removed by solid separation equipment, in the project baseline case, as if the BCS was never installed. Site-specific data must be used if available. If site-specific data is unavailable, values from table A.9 must be used to calculate $MS_{non\text{-}AS,L}$.

(n) The number of reporting days in the reporting period ($RD_{rp}$) must be calculated by subtracting the number of days the project is ineligible to report from the total number of reporting days in the reporting period. Ineligible days would include, but are not limited to, days with missing data beyond what is allowed to be substituted according to the methods in appendix B.

(o) The methane conversion factor for the non-anaerobic storage/treatment ($MCF_{non\text{-}AS}$) represents the non-anaerobic systems in place prior to BCS installation and must be obtained from table A.5 for the appropriate system type and average annual temperature ($^{o}C$).

**Equation 5.4: Modeled project baseline methane for non-anaerobic storage/treatment systems**

$$BE_{CH4,non-AS} = \sum_{L,i} (P_{L,i} \times MS_{non-AS,L} \times VS_L \times RD_{rm} \times MCF_{non-AS} \times B_{0,L}) \times 0.68 \times 0.001 \times GWP_{CH4}$$

| *Where,* | | | Units |
|---|---|---|---|
| $BE_{CH4,non-AS}$ | = | Total project baseline methane emissions from non-anaerobic storage/treatment systems for a reporting period, expressed in carbon dioxide equivalent | $mtCO_2e$ |
| $P_L$ | = | Monthly average population of livestock category 'L' | |
| $MS_{non-AS,L}$ | = | Fraction of volatile solids from livestock category 'L' managed in non-anaerobic storage/treatment systems | Fraction (0-1) |
| $VS_L$ | = | Volatile solids produced by livestock category 'L' on a dry matter basis | kg/ animal/ day |
| $RD_{rm}$ | = | Number of reporting days in the current reporting month | days |
| $MCF_{non-AS}$ | = | Methane conversion factor for non-anaerobic storage/treatment system 'S' from table A.5. | Fraction (0-1) |
| $B_{0,L}$ | = | Maximum methane producing capacity for manure for livestock category 'L' from table A.2 | $m^3$ $CH_4$/kg of VS dry matter |
| 0.68 | = | Density of methane (1 atm, $60^{o}F$) | $kg/m^3$ |
| 0.001 | = | Conversion factor from kg to mt | |
| $GWP_{CH4}$ | = | Global warming potential of methane | |
| i | = | Months in the reporting period | |

With:

$$VS_L = VS_{table} \times \frac{Mass_L}{1000}$$

*Where,* Units

| | | | |
|---|---|---|---|
| $VS_L$ | = | Volatile solid excretion on a dry matter weight basis | kg/ animal/ day |
| $VS_{table}$ | = | Volatile solid excretion from tables A.2 and A.4 | kg/ day/ 1000kg |
| $Mass_L$ | = | Average live weight for livestock category 'L' | kg |

### 5.2. Quantifying Project Methane Emissions

(a) Project methane emissions must be quantified for each reporting period.

(b) Project methane emissions for a reporting period ($PE_{CH4}$) must be quantified by using equation 5.5 and summing the project methane emissions for all SSRs which table 4.1 identifies as included within the project boundary.

**Equation 5.5: Project Methane Emissions**

$$PE_{CH4} = (PE_{CH4,\,BCS} + PE_{CH4,\,EP} + PE_{CH4,\,non\text{-}BCS}) \times GWP_{CH4}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{CH4}$ | = | Total project methane emissions for the reporting period | $mtCO_2e$ |
| $PE_{CH4,\,BCS}$ | = | Methane emissions from the BCS | $mtCH_4$ |
| $PE_{CH4,\,EP}$ | = | Methane emissions from the BCS effluent pond | $mtCH_4$ |
| $PE_{CH4,\,non\text{-}BCS}$ | = | Methane emissions from sources in the waste treatment and storage category other than the BCS and associated effluent | $mtCH_4$ |
| $GWP_{CH4}$ | = | Global warming potential of methane | |

(c) Project methane emissions from the BCS ($PE_{CH4,\,BCS}$) must be quantified using Equation 5.6.

(d) The quarterly methane concentration ($C_{CH4}$) is used for the entire month in which it is taken and for all subsequent months until a new methane concentration is taken. A weighted average of more frequent samples may also be used.

(e) A site-specific biogas destruction efficiency ($BDE_j$) of each device must be used when available, and when the destruction device is not listed in table A.6. If a site-specific methane destruction efficiency for devices listed in table A.6 is not available, then the default value from table A.6 must be used. Site-specific methane destruction efficiencies require prior written approval from the Executive Officer.

(f) Biogas flow to an inoperable device must be counted as a separate device with a biogas destruction efficiency ($BDE_j$) of zero when calculating the fractional monthly weighted average destruction efficiency of devices used during the month ($BDE_{i,weighted}$).

(g) Biogas capture efficiencies (BCE) must be taken from or calculated according to table A.3.

(h) All volume flows (F) must come from the monitored project-specific flow data corrected to standard conditions.

(i) The maximum biogas storage of the BCS system ($MS_{BCS}$) must be calculated using project-specific information and design documentation.

(j) The number of days for each uncontrolled venting ($t_k$) must be monitored and recorded at least daily from the time of discovery.

(k) The number of days for each uncontrolled venting ($t_k$) must date back to the last field check date without any uncontrolled venting events.

**Equation 5.6: Project Methane Emissions from the BCS**

$$PE_{CH4,BCS} = \sum_i \left[ \mathrm{CH}_{4\,\mathrm{meter},i} \times \left( \left(\frac{1}{BCE}\right) - BDE_{i,weighted} \right) + CH_{4\,vent,i} \right]$$

| *Where,* | | | Units |
|---|---|---|---|
| $PE_{CH4,\,BCS}$ | = | Methane emissions from the BCS | $mtCH_4$ |
| $CH_{4\ meter,i}$ | = | Quantity of methane collected and metered in month *i* | $mtCH_4$/ month |
| BCE | = | Fraction of monthly methane collected by the BCS from table A.3 | fraction (0-1) |
| $BDE_{i,weighted}$ | = | Monthly weighted average of all fractional destruction efficiencies of devices used in month *i*. | fraction (0-1) |
| $CH_{4\ vent,i}$ | = | The monthly quantity of methane that is vented to the atmosphere due to BCS venting events | mtCH4/ month |
| i | = | Months in the reporting period | |

With:

$$BDE_{i,weighted} = \frac{\sum_j (F_{j,i} \times BDE_j)}{\sum_j F_{Fj,i}}$$

| Where: | | | Units |
|---|---|---|---|
| j | = | Destruction devices | |
| Fj,i | = | Volume of biogas in month i sent to destruction device j | scf |
| BDEj | = | Biogas destruction efficiency of device j | fraction (0-1) |

And:

$$CH_{4\ meter,i} = F_i \times C_{CH4} \times 0.0423 \times 0.000454$$

| *Where,* | | | Units |
|---|---|---|---|
| $C_{CH4}$ | = | Quarterly methane concentration | fraction (0-1) |
| $F_i$ | = | Volume of biogas from the digester in month i | scf |

And:

$$CH_{4\,vent,i} = \sum_{k}\left(\left(F_{pw,k} \times t_k + MS_{BCS}\right) \times C_{CH4}\right) \times 0.04230 \times 0.00454$$

| *Where,* | | | Units |
|---|---|---|---|
| $F_{pw,k}$ | = | The average daily biogas production from the digester for the 7 days preceding the venting event k | scf/day |
| $t_k$ | = | The number of days for each uncontrolled venting event *k* from the BCS system (can be a fraction) | days |
| $MS_{BCS}$ | = | Maximum biogas storage of the BCS system | scf |
| $C_{CH4}$ | = | Quarterly methane concentration | fraction (0-1) |
| 0.04230 | = | Standard density of methane | lb $CH_4$/scf $CH_4$ |
| 0.000454 | = | Conversion factor from lb to mt | mt/lb |

(l) If gas flow metering equipment does not internally correct gas flow volumes to standard conditions, then equation 5.7 must be applied to the volume of biogas prior to calculating project methane emissions from the BCS in equation 5.6.

**Equation 5.7: Biogas Volume corrected for Temperature and Pressure**

$$F_{corrected,y} = F_{meas,y} \times \frac{519.67}{T_{meas,y}} \times \frac{P_{meas,y}}{1.00}$$

| Where: | | | Units |
|---|---|---|---|
| $F_{corrected,y}$ | = | Corrected volume of biogas for time interval y, adjusted to 60 $^oF$ and 1 atm | scf |
| $F_{meas,y}$ | = | Measured volume of biogas for time interval *y* | cf |
| $T_{meas,y}$ | | Measured temperature of the biogas for time interval *y*, $^oR={}^oF+459.67$ | $^oR$ |
| Pmeas,y | | Measured pressure of the biogas for the time interval *y* | atm |

(m) Project methane emissions from the BCS effluent pond ($PE_{CH4,ep}$) must be quantified using equation 5.8.

(n) Methane producing capacity for each livestock category ($B_{O,L}$) and volatile solids produced ($VS_{table}$) must use default values from tables A.2 and A.4 as applicable.

(o) The number of reporting days in the reporting period ($RD_{rp}$) must be calculated as the total number of reporting days in the reporting period.

(p) The methane conversion factor for the effluent pond ($MCF_{ep}$) must be obtained from table A.5 using the liquid/slurry system type and appropriate average annual temperature ($^oC$).

(q) The fraction of volatile solids ($MS_{L,BCS}$) sent to the BCS for each livestock category represents the fraction of manure that was sent to (managed by) the

BCS, taking into account any volatile solids removed by solid separation equipment. Site-specific data must be used if available. If site-specific data is unavailable, then values from table A.9 must be used to calculate $MS_{L,BCS}$.

(r) The average monthly population ($P_{L,i}$) must use site-specific data monitored and recorded at least monthly.

(s) The number of reporting days in the reporting month ($RD_{rm,i}$) must be calculated by subtracting the number of days not in the reporting period for the reporting month.

(t) The annual average live weight of the animals ($Mass_L$), per livestock category, must be taken from site-specific livestock mass data if the data are available. If site-specific data is unavailable, Typical Average Mass (TAM) values from table A.1 must be used.

**Equation 5.8 : Project Methane Emissions from the BCS Effluent Pond(s)**

$$PE_{CH4,EP} = \sum_{I} (VS_{ep} \times RD_{rp} \times 0.68 \times MCF_{ep} \times 0.001)$$

| *Where,* | | | Units |
|---|---|---|---|
| $PE_{CH4,\,EP}$ | = | Methane emissions from the effluent pond | $mtCH_4$ |
| I | = | Number of effluent ponds | |
| $VS_{ep}$ | = | Volatile solid to effluent pond | kg/day |
| $RD_{rp}$ | = | Reporting days in the reporting period | days |
| 0.68 | = | Density of methane (1 atm, 60°F) | $kg/m^3$ |
| $MCF_{ep}$ | = | Methane conversion factor from table A.4 | fraction (0-1) |
| 0.001 | = | Conversion factor from kg to mt | |

With:

$$VS_{ep} = \sum_{L} (VS_L \times P_L \times B_{O,L} \times MS_{L,BCS}) \times 0.3$$

| *Where,* | | | Units |
|---|---|---|---|
| $VS_L$ | = | VS produced by livestock category ‘L’ on a dry matter basis. | kg/ animal/ day |
| $P_L$ | = | Average population of livestock category ‘L’ (based on monthly population data) for a given reporting period | |
| $B_{O,L}$ | = | Maximum methane producing capacity for livestock category ‘L’ (of VS dry matter) | $m^3CH_4/kg$ |
| $MS_{L,BCS}$ | = | Fraction of manure from livestock category ‘L’ that is managed in the BCS | fraction (0-1) |
| 0.3 | = | Default value representing the amount of VS that exits the digester as a percentage of the VS entering the digester | |

And:

$$P_L = \frac{\sum_i (RD_{rm,i} \times P_{L,i})}{RD_{rp}}$$

| *Where,* | | | Units |
|---|---|---|---|
| $RD_{rm,i}$ | = | Reporting days in the reporting month | days |
| $P_{L,i}$ | = | Monthly average population of livestock category 'L' | |
| $RD_{rp}$ | = | Reporting days in the reporting period | days |

And:

$$VS_L = VS_{table} \times \frac{Mass_L}{1000}$$

| *Where,* | | | Units |
|---|---|---|---|
| $VS_L$ | = | Volatile solid excretion on a dry matter weight basis | kg/ animal/ day |
| $VS_{table}$ | = | Volatile solid excretion from tables A.2 and A.4 | kg/ day/ 1000kg |
| $Mass_L$ | = | Average live weight for livestock category 'L', | kg |

(u) Project methane emissions from manure management system components other than the BCS and the BCS effluent pond ($PE_{CH4,nBCS}$) must be quantified using equation 5.9.

(v) The methane conversion factor for systems other than the BCS and the effluent pond ($MCF_S$) must be obtained from table A.5 using the appropriate system type and average annual temperature ($^oC$).

(w) The fraction of volatile solids sent to systems other than the BCS and effluent pond ($MS_{L,S}$) for each livestock category represents the fraction of manure that was sent to (managed by) these systems, taking into account any volatile solids removed by solid separation equipment. Site-specific data must be used if available. If site-specific data is unavailable, values from table A.9 must be used to calculate $MS_{L,S}$.

**Equation 5.9: Project Methane Emissions from *Non*-BCS Related Sources**

$$PE_{CH4,nBCS} = \left( \sum_L (EF_{CH4,L,nBCSs} \times P_L) \right) \times 0.001$$

| *Where,* | | | Units |
|---|---|---|---|
| $PE_{CH4,\ nBCS}$ | = | Methane from sources in the waste treatment and storage category other than the BCS and associated effluent pond | $mtCH_4$ |
| $EF_{CH4,L,nBCSs}$ | = | Emission factor for the livestock population from non-BCS-related sources (nBCSs, calculated below) | $kgCH_4$/ head/ yr |
| $P_L$ | = | Average population of livestock category 'L' (based on monthly population data) for a given reporting period | |
| 0.001 | = | Conversion factor from kg to mt | |

$$EF_{CH4,L,nBCSs} = \left(VS_L \times B_{o,L} \times \mathrm{RD}_{\mathrm{rp}} \times 0.68\right) \times \left(\sum_S (MCF_S \times MS_{L,S})\right)$$

| *Where,* | | | Units |
|---|---|---|---|
| $EF_{CH4,L,nBCS}$ | = | Methane emission factor for the livestock population from non-BCS related sources | $kgCH_4$/ head/ yr |
| $VS_L$ | = | Volatile solids produced by livestock category 'L' on a dry matter basis. | kg/ animal/ day |
| $B_{o,L}$ | = | Maximum methane producing capacity for manure for livestock category 'L' (of VS dry matter) from table A.2 | $m^3$ $CH_4$/kg |
| $RD_{rp}$ | = | reporting days in a reporting period | days/yr |
| 0.68 | = | Density of methane (1 atm, 60$^o$F) | kg/$m^3$ |
| $MCF_S$ | = | Methane conversion factor for system component 'S' from table A.4 | fraction (0-1) |
| $MS_{L,S}$ | = | Percent of manure from livestock category L that is managed in non-BCS system component 'S' | fraction (0-1) |

And:

$$VS_L = VS_{Table} \times \frac{Mass_L}{1000}$$

| *Where,* | | | Units |
|---|---|---|---|
| $VS_L$ | = | Volatile solid excretion on a dry matter weight basis | kg/ animal/ day |
| $VS_{Table}$ | = | Volatile solid excretion from tables A.2 and A.4 | kg/ day/ 1000kg |
| $Mass_L$ | = | Average live weight for livestock category 'L', | kg |

And:

$$P_L = \frac{\sum_i \left(RD_{rm,i} \times P_{L,i}\right)}{RD_{rp}}$$

| *Where,* | | | Units |
|---|---|---|---|
| $RD_{rm,i}$ | = | Reporting days in the reporting month | days |
| $P_{L,i}$ | = | Monthly average population of livestock category 'L' | |
| $RD_{rp}$ | = | Reporting days in the reporting period | days |

### 5.3. Metered Methane Destruction Comparison

Offset projects must compare the modeled methane emission reductions for the reporting period, as calculated in equation 5.2 above, with the actual metered amount of methane that is destroyed by the BCS over the same period. The lesser of the two values is to be used as the total methane emission reductions for the reporting period in question.

(a) The total metered methane destruction ($CH_{4\ destroyed}$) must be quantified using equation 5.10.

(b) The quarterly methane concentration ($C_{CH4}$) is used for the entire month in which it is taken and for all subsequent months until a new methane concentration is taken. A weighted average of more frequent samples may also be used.

(c) All volume flows (F) must come from the monitored project-specific flow data corrected to standard conditions.

(d) A site-specific biogas destruction efficiency ($BDE_j$) of each device must be used when available, and when the destruction device is not listed in table A.6. If a site-specific methane destruction efficiency for devices listed in table A.6 is not available then the default value from table A.6 must be used. Site-specific methane destruction efficiencies require prior written approval from the Executive Officer and must be equally or more accurate than the default destruction efficiencies.

(e) Biogas flow to an inoperable device must be counted as a separate device with a biogas destruction efficiency ($BDE_j$) of zero when calculating the fractional monthly weighted average destruction efficiency of devices used during the month ($BDE_{i,weighted}$).

**Equation 5.10 : Metered Methane Destruction**

$$CH_{4,destroyed} = \sum_i (CH_{4meter,i} \times BDE_{i,weighted}) \times GWP_{CH4}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $CH_{4,destroyed}$ | = | Aggregated quantity of methane collected and destroyed during the reporting period | $mtCO_2e$ |
| $CH_{4\ meter,i}$ | = | Monthly quantity of methane collected and metered. | $mtCH_4$/ month |
| $BDE_{i,weighted}$ | = | Monthly weighted average of all destruction devices used in month *i* | fraction (0-1) |
| $GWP_{CH4}$ | = | Global warming potential of methane | |

With:

$$CH_{4\ meter,i} = F_i \times C_{CH4} \times 0.0423 \times 0.000454$$

*Where,*

| | | | Units |
|---|---|---|---|
| $C_{CH4}$ | = | Quarterly methane concentration | fraction (0-1) |
| $F_i$ | = | Volume of biogas from the digester in month *i* | scf |

And:

$$BDE_{i,weighted} = \frac{\sum_j (F_{j,i} \times BDE_j)}{\sum_j F_{F\,j,i}}$$

*Where:*

| | | | Units |
|---|---|---|---|
| j | = | Destruction devices | |
| $F_{j,i}$ | = | Volume of biogas in month *i* sent to destruction device *j* | scf |
| $BDE_j$ | = | Biogas destruction efficiency of device *j* | Fraction (0-1) |

(f) If gas flow metering equipment does not internally correct gas flow volumes to standard conditions, the Offset Project Operator or, if applicable, the Authorized Project Designee must apply equation 5.11 to the volume of biogas prior to calculating metered methane destruction in eqution 5.10.

**Equation 5.11: Biogas Volume corrected for Temperature and Pressure**

$$F_{corrected,y} = F_{meas,y} \times \frac{519.67}{T_{meas,y}} \times \frac{P_{meas,y}}{1.00}$$

Where:

| | | | Units |
|---|---|---|---|
| $F_{corrected,y}$ | = | Corrected volume of biogas for time interval y, adjusted to 60 °F and 1 atm | scf |
| $F_{meas,y}$ | = | Measured volume of biogas for time interval y | cf |
| $T_{meas,y}$ | = | Measured temperature of the biogas for time interval y, °R=°F+459.67 | °R |
| Pmeas,y | = | Measured pressure of the biogas for the time interval y | atm |

### 5.4. Quantifying Project Baseline and Project Carbon Dioxide Emissions

(a) Carbon dioxide emissions associated with the project baseline or project activities include, but are not limited to, the following sources:

(1) Electricity use by pumps and equipment;

(2) Fossil fuel generators used to destroy biogas;

(3) Power pumping systems;

(4) Milking parlor equipment;

(5) Flares;

(6) Tractors that operate in barns or freestalls;

(7) On-site manure hauling trucks; and

(8) Vehicles that transport manure off-site.

(b) If it is demonstrated during verification that project carbon dioxide emissions are to be equal to or less than 5% of the total project baseline emissions of methane, project baseline and project carbon dioxide emissions may be estimated.

(c) Baseline carbon dioxide emissions ($BE_{CO2}$) must be calculated using equation 5.12.

(d) The baseline quantities of electricity ($BE_{QE,c}$) and fossil fuel ($BE_{QF,c}$) consumed by each source must be taken from operational records such as utility bills and delivery invoices unless the Offset Project Operator or Authorized Project Designee is allowed to estimate baseline carbon dioxide emissions pursuant to subchapter 5.4(b) of this protocol.

(e) If the total electricity being generated by project activities is greater than or equal to the additional electricity consumption by the project ($PE_{QE,c}$ - $BE_{QE,c}$) the baseline ($BE_{QE,c}$) and project ($PE_{QE,c}$) electricity consumption will both be set to zero.

**Equation 5.12 Baseline Carbon Dioxide Emissions**

$$BE_{CO2} = \sum_{c}(BE_{QE,c} \times EF_{CO2,e}) + \sum_{c}(BE_{QF,c} \times EF_{CO2,f}) \times 0.001$$

| *Where,* | | | Units |
|---|---|---|---|
| $BE_{CO2}$ | = | Baseline anthropogenic carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources | mtCO2e |
| $BE_{QE,c}$ | = | Baseline quantity of electricity consumed for each emissions source 'c' | MWh |
| $EF_{CO2,e}$ | = | $CO_2$ emission factor *e* for electricity used; see appendix A for emission factors by eGRID subregion | mtCO2/MWh |
| $EF_{CO2,f}$ | = | Fuel-specific emission factor *f* from appendix A | kg CO2/MMBtu or kg CO2/gal |
| $BE_{QF,c}$ | = | Baseline quantity of fuel consumed for each mobile and stationary emission source 'c' | MMBtu or gal |
| 0.001 | = | Conversion factor from kg to mt | |

(f) Project carbon dioxide emissions ($PE_{CO2}$) must be calculated using equation 5.13.

(g) The project quantities of electricity ($PE_{QE,c}$) and fossil fuel ($PE_{QF,c}$) consumed by each source must be taken from operational records such as utility bills and delivery invoices unless the Offset Project Operator or Authorized Project Designee is allowed to estimate project carbon dioxide emissions pursuant to subchapter 5.4(b) of this protocol.

**Equation 5.13 Project Carbon Dioxide Emissions**

$$PE_{CO2} = \sum_{c}(PE_{QE,c} \times EF_{CO2,e}) + \sum_{c}(PE_{QF,c} \times EF_{CO2,f}) \times 0.001$$

| *Where,* | | | Units |
|---|---|---|---|
| $PE_{CO2}$ | = | Project anthropogenic carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources | mtCO2e |
| $PE_{QE,c}$ | = | Project quantity of electricity consumed for each emissions source 'c' | MWh |

| | | | |
|---|---|---|---|
| $EF_{CO2,e}$ | = | $CO_2$ emission factor *e* for electricity used; see appendix A for emission factors by eGRID sub region | mtCO2/MWh |
| $EF_{CO2,f}$ | = | Fuel-specific emission factor *f* from appendix A | kg CO2/MMBtu or kg CO2/gal |
| $PE_{QF,c}$ | = | Project quantity of fuel consumed for each mobile and stationary emission source 'c' | MMBtu or gal |
| 0.001 | = | Conversion factor from kg to mt | |

# Chapter 6. Monitoring

## 6.1. General Monitoring Requirement - Quantification Methodology

(a) The Offset Project Operator or Authorized Project Designee is responsible for monitoring the performance of the offset project and operating each component of the biogas collection and destruction system in a manner consistent with the manufacturer's specifications.

(b) The Offset Project Operator or, if applicable, the Authorized Project Designee must monitor the methane capture and control system with measurement equipment that directly meters:

(1) The total flow of biogas, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure, prior to delivery to the destruction device(s);

(2) The total flow of biogas can come from one meter or summed from multiple meters;

(3) The flow of biogas delivered to each destruction device, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure. A single meter may be used for multiple destruction devices. In this instance, methane destruction in these devices is eligible only if the operational activity of all these devices are independently monitored and the least efficient BDE of all destruction devices is used; and

(4) The fraction of methane in the biogas must be measured with a continuous analyzer or, alternatively, with quarterly measurements.

(c) Flow data must be corrected for temperature and pressure at $60^{o}$F and 1 atm, either internally or by following equation 5.6.

(d) The Offset Project Operator or, if applicable, the Authorized Project Designee must independently monitor the operational activity of each destruction device and must collect and maintain documentation at least hourly to ensure actual methane destruction. No registry offset credits or ARB offset credits will be issued for any time period during which the destruction device is not operational.

(1) Any destruction device equipped with a safety shut off device that prevents biogas flow to the destruction device when the destruction device is not operational does not require hourly monitoring, provided that the presence, operability, and use of the safety device are verified.

(e) If for any reason the destruction device or the operational monitoring equipment is inoperable, during the period of inoperability, the destruction efficiency of the device is zero.

(f) Data substitution is allowed for limited circumstances where a project encounters biogas flow rate or methane concentration data gaps. The Offset Project Operator or, if applicable, Authorized Project Designee must apply the data substitution methodology provided in appendix B. 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.

(g) Data substitution is required for all circumstances where a projects encounters project flow rate or methane concentration gaps. The Offset Project Operator or, if applicable, Authorized Project Designee must apply the data substitution methodology provided in appendix B. 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. Biogas Measurement Instrument QA/QC – Quantification Methodology

(a) All gas flow meters and continuous methane analyzers must be:

(1) Cleaned and inspected on a quarterly basis, with the activities performed and “as found/as left condition” of the equipment documented;

(2) Field checked by a trained professional for calibration accuracy with the percent drift documented, using either a portable instrument (such as a pitot tube), a permanent fixture or manufacturer specifications, at the end of but no more than two months prior to the end date of the reporting period; and

(3) Calibrated by the manufacturer or a certified calibration service per manufacturer's specifications or every 5 years, whichever is more frequent.

(b) If the field check on a piece of equipment after cleaning reveals accuracy outside of a +/- 5% threshold, the equipment must be calibrated by the manufacturer or a certified service provider. The Offset Project Operator or, if applicable, Authorized Project Designee must maintain documentation of efforts to calibrate the equipment within 30 days of the failed field check or a biogas destruction efficiency of zero must be assigned to all destruction devices monitored by the equipment from date of discovery until calibration.

(c) For the interval between the last successful field check and any calibration event confirming accuracy outside the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful field check until such time as the meter is properly calibrated.

(1) For calibrations that indicate the flow meter was outside the +/- 5% accuracy threshold, the project developer must estimate total emission reductions independently for each meter using:

(A) The metered values without correction; and

(B) The metered values adjusted based on the greatest calibration drift recorded at the time of calibration.

(2) The lower of the two emission reduction estimates must be reported as the scaled emission reduction estimate.

(d) If a portable instrument is used (such as a handheld methane analyzer), the portable instrument must be calibrated per manufacturer's specifications or at least once during each reporting period, whichever is more frequent, by the manufacturer or at an ISO 17025 certified laboratory.

### 6.3. Document Retention

(a) The Offset Project Operator or Authorized Project Designee is required to keep all documentation and information outlined in the Regulation and this protocol. Record retention requirements are set forth in section 95976 of the Regulation.

(b) Information that must be retained by the Offset Project Operator or Authorized Project Designee must include, but is not limited to:

- (1) All data inputs for the calculation of the project baseline emissions and project emission reductions;
- (2) Emission reduction calculations;
- (3) Relevant sections of the BCS operating permits;
- (4) BCS information (installation dates, equipment list, etc.);
- (5) Biogas flow meter information (model number, serial number, manufacturer's calibration procedures) ;
- (6) Cleaning and inspection records for all biogas meters;
- (7) Field check results for all biogas meters;
- (8) Calibration results for all biogas meters;
- (9) Methane monitor information (model number, serial number, calibration procedures);
- (10) Biogas flow data (for each flow meter);
- (11) Biogas temperature and pressure readings (only if flow meter does not correct for temperature and pressure automatically);
- (12) Methane concentration monitoring data;
- (13) Destruction device monitoring data (for each destruction device);
- (14) Destruction device, methane monitor and biogas flow monitor information (model numbers, serial numbers, calibration procedures); and
- (15) All maintenance records relevant to the BCS, monitoring equipment, and destruction devices.

(c) If using a calibrated portable gas analyzer for $CH_4$ content measurement, all of the following information must also be included:

- (1) Date, time, and location of methane measurement;
- (2) Methane content of biogas (% by volume) for each measurement ;
- (3) Methane measurement instrument type and serial number;

(4) Date, time, and results of instrument calibration; and

(5) Corrective measures taken if instrument does not meet performance specifications.

(d) See the Regulation for additional record-keeping requirements.

### 6.4. Monitoring Parameters – Quantification Methodology

Provisions for monitoring other variables to calculate project baseline and project emissions are provided in table 6.1.

**Table 6.1.** Project Monitoring Parameters

| Eq. # | Parameter | Description | Data unit | calculated (c) measured (m) reference(r) operating records (o) | Measurement frequency | Comment |
|---|---|---|---|---|---|---|
| **General Project Parameters** | | | | | | |
| 5.1<br>5.6<br>5.10 | $CH_{4\ meter}$ | Amount of methane collected and metered in BCS | Metric tons of CH4 (tCH4) | c, m | Monthly | Calculated from biogas flow and methane fraction meter readings (See 'F' and '$C_{CH4}$' parameters below). Verifier: Review meter reading data; Confirm proper operation and maintenance in accordance with the manufacturer's specifications; Confirm meter calibration data. |
| 5.2<br>5.3 | L | Type of livestock categories on the farm | Livestock categories | o | Monthly | Select from list provided in table A.1. Verifier: Review herd management software; Conduct site visit; Interview operator. |
| 5.3 | $VS_{deg}$ | Monthly volatile solids degraded in each anaerobic storage system, for each livestock category | kg | c, o | Monthly | Calculated value from operating records. *Verifier*: Ensure proper calculations; Review operating records. |
| 5.3<br>5.4<br>5.8<br>5.9 | $B_{0,L}$ | Maximum methane producing capacity for manure by livestock category | (m3 CH4/kgVS) | r | Once per reporting period | From table A.2. Verifier: Verify correct value from table used. |
| 5.3 | $VS_{avail}$ | Monthly volatile solids available for degradation in each anaerobic storage system, for each livestock category | kg | c, o | Monthly | Calculated value from operating records. Verifier: Ensure proper calculations; Review operating records. |
| 5.3<br>5.4<br>5.8<br>5.9 | $VS_L$ | Daily volatile solid production | (kg/animal/ day) | r, c | Once per reporting period | From table A.2 and table A.4; Verifier: Ensure appropriate year's table is used; Review data units. |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5.3 | f | Van't Hoff-Arrhenius factor | n/a | c | Monthly | The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system.<br>Verifier: Ensure proper calculations; Review calculation; Review temperature data. |
| 5.3<br>5.4<br>5.8<br>5.9 | $P_L$ | Average number of animals for each livestock category | Population (# head) | o | Monthly | Verifier: Review herd management software; Review local air and water quality agency reporting submissions, if available (e.g. in CA, dairies with more than 500 cows report farm information to ARB). |
| 5.3<br>5.4<br>5.8<br>5.9 | $Mass_L$ | Average live weight by livestock category | kg | o, r | Monthly | From operating records, or if on-site data is unavailable, from lookup table (table A.1).<br>Verifier: Conduct site visit; Interview livestock operator;<br>Review average daily gain records, operating records. |
| 5.3 | $T_2$ | Average monthly temperature at location of the operation | oC | m/o | Monthly | Used for van't Hoff-Arrhenius factor calculation and for choosing appropriate MCF value.<br>Verifier: Review temperature records obtained from weather service. |
| 5.6 | $CH_{4\ meter,i}$ | Quantity of methane collected and metered in month i | $mtCH_4$/Month | m/o | Monthly | Used for calculating $PE_{CH4,\ BCS}$. |
| 5.6 | BCE | Biogas capture efficiency of the anaerobic digester, accounts for gas leaks. | Fraction (0-1) | r | Once per reporting period | Use default value from table A.3.<br>Verifier: Review operation and maintenance records to ensure proper functionality of BCS. |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5.6<br>5.10 | BDE | Methane destruction efficiency of destruction device(s) | Fraction (0-1) | r, c | Monthly | Reflects the actual efficiency of the system to destroy captured methane gas – accounts for different destruction devices. See Equation 5.6.<br>Verifier: Confirm evidence of proper and continuous operation in accordance with the manufacturer's specifications. |
| 5.6 | $C_{CH4}$ | Methane concentration of biogas | Fraction (0-1) | m | Quarterly | Use a direct sampling approach that yields a value with at least 95% confidence. Samples to be taken at least quarterly.<br>Calibrate monitoring instrument in accordance with the manufacturer's specifications.<br>Verifier: Review meter reading data; Confirm proper operation in accordance with the manufacturer's specifications. |
| 5.6<br>5.7<br>5.10<br>5.11 | F | Monthly volume of biogas from digester to destruction devices | scf/month | m | Continuously, aggregated monthly | Measured continuously from flow meter and recorded every 15 minutes or totalized and recorded at least once daily. Data to be aggregated monthly.<br>Verifier: Review meter reading data; Confirm proper aggregation of data; Confirm proper operation in accordance with the manufacturer's specifications; Confirm meter calibration data. |
| 5.6 | $F_{pw}$ | The average flow of biogas from the digester for the entire week prior to the uncontrolled venting event | scf/day | m | Weekly | The average flow of biogas can be determined from the daily records from the previous week. |
| 5.6 | t | The number of days of the month that biogas is venting uncontrolled from the project's BCS. | Days | m, o | Monthly | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5.6 | $MS_{BCS}$ | The maximum biogas storage of the BCS system | scf | r | Once per reporting period | Obtained from digester system design plans. Necessary to quantify the release of methane to the atmosphere due to an uncontrolled venting event. |
| 5.7<br>5.11 | T | Temperature of the biogas | °R (Rankine) | m | Continuously, averaged monthly | Measured to normalize volume flow of biogas to STP. No separate monitoring of temperature is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet. |
| 5.8 | $VS_{ep}$ | Average daily volatile solid of digester effluent to effluent pond | kg/day | c | Once per reporting period | If project uses effluent pond, equals 30% of the average daily VS entering the digester. Verifier: Review VSep calculations. |
| 5.8 | $MCF_{ep}$ | Methane conversion factor for BCS effluent pond | Fraction (0-1) | r | Once per reporting period | Referenced from appendix A. The Offset Project Operator or Authorized Project Designee must use the liquid slurry MCF value. Verifier: Verify value from table. |
| 5.8 | $MS_{L,BCS}$ | Fraction of manure from each livestock category managed in the BCS | Fraction (0-1) | o | Once per reporting period | Used to determine the total VS entering the digester. The percentage should be tracked in operational records. Verifier: Check operational records and conduct site visit. |
| 5.9 | $EF_{CH4,L}$ (nBCSs) | Methane emission factor for the livestock population from non-BCS-related sources | (kgCH4/head/year) | c | Once per reporting period | Emission factor for all non-BCS storage systems, differentiated by livestock category. Verifier: Review calculation, operation records. |
| 5.9 | $MCF_s$ | Methane conversion factor for manure management system component 'S' | Fraction (0-1) | r | Once per reporting period | From appendix A. Differentiate by livestock category Verifier: Verify correct value from table used. |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5.9 | $MS_L$ | Fraction of manure from each livestock category managed in the baseline waste handling system 'S' | Fraction (0-1) | o | Once per reporting period | Reflects the percent of waste handled by the system components 'S' pre-project. Applicable to the entire operation. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 100%. Verifier: Conduct site visit; Interview operator; Review baseline scenario documentation. |
| 5.9 | $MS_{L,S}$ | Fraction of manure from each livestock category managed in non-anaerobic manure management system component 'S' | Fraction (0-1) | o | Monthly | Based on configuration of manure management system, differentiated by livestock category. Verifier: Conduct site visit; Interview operator. |
| 5.10 | $CH_{4,destroyed}$ | Aggregated amount of methane collected and destroyed in the BCS | Metric tons of CH4 | c, m | Once per reporting period | Calculated as the collected methane times the destruction efficiency (see the 'CH4,meter ' and 'BDE' parameters below) Verifier: Review meter reading data, confirm proper operation of the destruction device(s); Ensure data is accurately aggregated over the correct amount of time. |
| 5.12 | $BE_{QEc}$ | Baseline quantity of electricity consumed | MWh/year | o, c | Once per reporting period | Electricity used by project for manure collection, transport, treatment/storage, and disposal. Verifier: Review operating records and quantity calculation. |
| 5.12 5.13 | $EF_{CO2,e}$ | Emission factor for electricity used by project | tCO2/MWh | r | Once per reporting period | Refer to appendix A for emission factors. If biogas produced from digester is used to generate electricity consumed, the emission factor is zero. Verifier: Review emission factors. |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5.12 5.13 | $EF_{CO2,f}$ | Fuel-specific emission factor for mobile and stationary combustion sources | kg CO2/MMBTU or kg CO2/gallon | r | Once per reporting period | Refer to appendix A for emission factors. If biogas produced from digester is used as an energy source, the emission factor is zero. Verifier: Review emission factors. |
| 5.12 | $BE_{QFc}$ | Baseline quantity of fuel used for mobile/stationary combustion sources | MMBTU/year or gallon/year | o, c | Once per reporting period | Fuel used by project for manure collection, transport, treatment/storage, and disposal, and stationary combustion sources including supplemental fossil fuels used in combustion device. Verifier: Review operating records and quantity calculation. |
| 5.13 | $PE_{QEc}$ | Project quantity of electricity consumed | MWh/year | o, c | Once per reporting period | Electricity used by project for manure collection, transport, treatment/storage, and disposal. Verifier: Review operating records and quantity calculation. |
| 5.13 | $PE_{QFc}$ | Project quantity of fuel used for mobile/stationary combustion sources | MMBTU/year or gallon/year | o, c | Once per reporting period | Fuel used by project for manure collection, transport, treatment/storage, and disposal, and stationary combustion sources including supplemental fossil fuels used in combustion device. Verifier: Review operating records and quantity calculation. |

## Chapter 7. Reporting

General requirements for reporting and record retention are included in the Regulation. In addition to the offset project requirements in sections 95975 and 95976 the Regulation, livestock offset projects must follow the project listing and reporting requirements below.

### 7.1. Listing Requirements

(a) Listing information must be submitted by the Offset Project Operator or Authorized Project Designee no later than the date on which the Offset Project Operator or Authorized Project Designee submits the first Offset Project Data Report.

(b) In order for a livestock Compliance Offset Project to be listed, the Offset Project Operator or Authorized Project Designee must submit the information required by section 95975 of the Regulation, in addition to all the following information:

- (1) Offset project name and ID number(s);
- (2) Name and CITSS ID number for the:
  - (A) Offset Project Operator; and,
  - (B) Authorized Project Designee (if applicable);
- (3) Contact information for both the Offset Project Operator and, if applicable, the Authorized Project Designee, including all of the following information:
  - (A) Entity's mailing address;
  - (B) Contact person's name;
  - (C) Contact person's phone number; and
  - (D) Contact person's email address;
- (4) Contact information, including name, phone number, email address, and, if applicable, the organizational affiliation for:
  - (E) The person submitting the listing information;
  - (F) Technical consultants; and
  - (G) Other parties with a material interest;
- (5) Name of facility owner;
- (6) Date of form completion;
- (7) Offset project description: 1-2 paragraphs (including type of digester and method of destruction);
- (8) Offset project site address (including all governing jurisdictions and latitude/longitude);

(9) Name and address of animal facility (if different from project site);

(10) Description of type of facility (e.g., dairy, swine, or combined);

(11) Offset project commencement date;

(12) Initial reporting period start and end dates;

(13) Indication whether any GHG reductions associated with the offset project have ever been registered with or claimed by another registry or program, or sold to a third party prior to our listing; if so, identification of the registry or program, as well as vintage and reporting period; and

(14) Indication whether the offset project is being implemented and conducted as the result of any law, statute, regulation, court order, or other legally binding mandate. If so, an explanation must also be provided;

### 7.2. Offset Project Data Report

(a) The Offset Project Operator or, if applicable, Authorized Project Designee must submit an Offset Project Data Report at the conclusion of each Reporting Period according to the reporting schedule in section 95976 of the Regulation.

(b) The Offset Project Operator or, if applicable, Authorized Project Designee must submit the information required by section 95976 of the Regulation, in addition to all of the following information:

(1) Offset project name and ID number(s);

(2) Name and CITSS ID number for the:

(A) Offset Project Operator; and,

(B) Authorized Project Designee (if applicable);

(3)

(C) Contact information for both the Offset Project Operator and, if applicable, the Authorized Project Designee, including all of the following information: Entity's mailing address;

(D) Contact person's name;

(E) Contact person's phone number; and

(F) Contact person's email address;

(4) Contact information including name, phone number, email address, and, if applicable, the organization affiliation for the person submitting the reporting information;

(5) Date OPDR completed;

(6) Reporting period start and end dates;

(7) Indication whether the offset project meets all local, state, or federal regulatory requirements;

(8) Offset project commencement date;

(9) Facility name and location;

(10) Indication whether all the information in the offset project listing is still accurate. If not provide updates;

(11) Project baseline emissions;

(12) Project emissions; and

(13) Total GHG emission reductions.

## Chapter 8. Verification

(a) All Offset Project Data Reports are subject to regulatory verification as required in section 95977 of the Regulation by an ARB accredited offset verification body.

(b) The Offset Project Data Reports must receive a positive or qualified positive verification statement to be issued ARB or registry offset credits.

## Appendix A Emissions Factor Tables – Quantification Methodology

**Table A.1.** Livestock Categories and Typical Average Mass ($Mass_L$)

| Livestock Category (L) | Livestock Typical Average Mass (TAM) in kg |
|---|---|
| Dairy cows (on feed) | 680 |
| Non-milking dairy cows (on feed) | 684 |
| Heifers (on feed) | 407 |
| Bulls (grazing) | 874 |
| Calves (grazing) | 118 |
| Heifers (grazing) | 351.5 |
| Cows (grazing) | 582.5 |
| Nursery swine | 12.5 |
| Grow/finish swine | 70 |
| Breeding swine | 198 |

**Table A.2.** Volatile Solids and Maximum Methane Potential by Livestock Category

| Livestock category (*L*) | $VS_{Table}$ (kg/day/1,000 kg mass) | $B_{o,L}$ ($m^3$ $CH_4$/kg VS added) |
|---|---|---|
| Dairy cows | See table A.4 | 0.24 |
| Non-milking dairy cows | 5.56 | 0.24 |
| Heifers | See table A.4 | 0.17 |
| Bulls (grazing) | 6.04 | 0.17 |
| Calves (grazing) | 7.70 | 0.17 |
| Heifers (grazing) | See table A.4 | 0.17 |
| Cows (grazing) | See table A.4 | 0.17 |
| Nursery swine | 8.89 | 0.48 |
| Grow/finish swine | 5.36 | 0.48 |
| Breeding swine | 2.71 | 0.35 |

**Table A.3.** Biogas Collection Efficiency by Digester Type

| Digester Type | Cover Type | Biogas Collection Efficiency (BCE) |
|---|---|---|
| Covered Anaerobic Lagoon | Bank-to-Bank, impermeable | 0.95 |
| | Partial area (modular), impermeable | 0.95 x % area covered |
| Complete mix, plug flow, or fixed film digester | Enclosed vessel | 0.98 |

**Table A.4.** 2012 Volatile Solid ($VS_{table}$). Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows- Grazing by State (kg/day/1000 kg mass)

| State | VS Dairy Cow | VS Heifer | VS Heifer-Grazing | VS Cows- Grazing |
|---|---|---|---|---|
| Alabama | 8.62 | 8.44 | 19.67 | 7.82 |
| Alaska | 8.71 | 8.44 | 30.94 | 8.89 |
| Arizona | 11.64 | 8.44 | 22.32 | 8.89 |
| Arkansas | 8.44 | 8.44 | 18.38 | 7.82 |
| California | 11.41 | 8.44 | 13.96 | 8.89 |
| Colorado | 11.64 | 8.44 | 12.28 | 8.89 |
| Connecticut | 10.41 | 8.44 | 23.35 | 7.87 |
| Delaware | 10.18 | 8.44 | 16.82 | 7.87 |
| Florida | 10.36 | 8.44 | 21.99 | 7.82 |
| Georgia | 10.40 | 8.44 | 19.17 | 7.82 |
| Hawaii | 8.70 | 8.44 | 20.25 | 8.89 |
| Idaho | 11.45 | 8.44 | 13.75 | 8.89 |
| Illinois | 10.30 | 8.44 | 11.42 | 7.47 |
| Indiana | 10.85 | 8.44 | 11.72 | 7.47 |
| Iowa | 10.96 | 8.44 | 9.54 | 7.47 |
| Kansas | 10.94 | 8.44 | 8.99 | 7.47 |
| Kentucky | 9.20 | 8.44 | 14.69 | 7.82 |
| Louisiana | 8.41 | 8.44 | 21.36 | 7.82 |
| Maine | 10.01 | 8.44 | 15.12 | 7.87 |
| Maryland | 10.20 | 8.44 | 17.18 | 7.87 |
| Massachusetts | 9.91 | 8.44 | 20.89 | 7.87 |
| Michigan | 11.56 | 8.44 | 12.19 | 7.47 |
| Minnesota | 10.29 | 8.44 | 11.47 | 7.47 |
| Mississippi | 8.96 | 8.44 | 19.31 | 7.82 |
| Missouri | 8.92 | 8.44 | 14.84 | 7.47 |
| Montana | 10.85 | 8.44 | 18.50 | 7.82 |
| Nebraska | 10.79 | 8.44 | 11.97 | 8.89 |
| Nevada | 11.33 | 8.44 | 14.77 | 7.47 |
| New Hampshire | 10.34 | 8.44 | 23.83 | 8.92 |
| New Jersey | 10.01 | 8.44 | 16.56 | 7.87 |
| New Mexico | 11.85 | 8.44 | 14.27 | 7.87 |
| New York | 10.93 | 8.44 | 16.72 | 8.89 |
| North Carolina | 10.79 | 8.44 | 19.93 | 7.87 |
| North Dakota | 10.22 | 8.44 | 14.61 | 7.82 |
| Ohio | 10.39 | 8.44 | 13.24 | 7.47 |
| Oklahoma | 9.76 | 8.44 | 12.67 | 7.47 |
| Oregon | 10.57 | 8.44 | 15.75 | 7.82 |

| | | | | |
|---|---|---|---|---|
| Pennsylvania | 10.32 | 8.44 | 16.19 | 8.89 |
| Rhode Island | 9.93 | 8.44 | 20.89 | 7.87 |
| South Carolina | 9.85 | 8.44 | 19.71 | 7.87 |
| South Dakota | 10.86 | 8.44 | 12.77 | 7.82 |
| Tennessee | 9.49 | 8.44 | 16.25 | 7.47 |
| Texas | 11.06 | 8.44 | 11.15 | 7.82 |
| Utah | 10.95 | 8.44 | 16.65 | 7.82 |
| Vermont | 10.23 | 8.44 | 16.08 | 8.89 |
| Virginia | 10.06 | 8.44 | 17.93 | 7.87 |
| Washington | 11.58 | 8.44 | 12.06 | 7.82 |
| West Virginia | 9.18 | 8.44 | 19.13 | 8.89 |
| Wisconsin | 10.87 | 8.44 | 17.03 | 7.47 |
| Wyoming | 10.69 | 8.44 | 18.18 | 8.89 |

**Table A.5.** IPCC 2006 Methane Conversion Factors by Manure Management System Component/Methane Source 'S'

**MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS**

| **System** | | **MCFs by average reporting period temperature (°C)** | | | | | | | | | | | | | | | | | | | **Source and comments** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Cool** | | | | | **Temperate** | | | | | | | | | | | **Warm** | | | |
| | | **≤ 10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** | **27** | **≥ 28** | |
| Pasture/Range/Paddock | | 0.01 | | | | | 0.02 | | | | | | | | | | | 0.02 | | | Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994). |
| Daily spread | | 0.001 | | | | | 0.02 | | | | | | | | | | | 0.01 | | | Hashimoto and Steed (1993). |
| Solid storage | | 0.02 | | | | | 0.04 | | | | | | | | | | | 0.05 | | | Judgment of IPCC Expert Group in combination with Amon et al. (2001), which shows emissions of approximately 2% in winter and 4% in summer. Warm climate is based on judgment of IPCC Expert Group and Amon et al. (1998). |
| Dry lot | | 0.01 | | | | | 0.02 | | | | | | | | | | | 0.02 | | | Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994). |
| Liquid / Slurry | With natural crust cover | 0.10 | 0.11 | 0.13 | 0.14 | 0.15 | 0.17 | 0.18 | 0.20 | 0.22 | 0.24 | 0.26 | 0.29 | 0.31 | 0.34 | 0.37 | 0.41 | 0.44 | 0.48 | 0.50 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001) and Sommer (2000). The estimated reduction due to the crust cover (40%) is an annual average value based on a limited data set and can be highly variable |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | dependent on temperature, rainfall, and composition. When slurry tanks are used as fed-batch storage/digesters, MCF should be calculated according to Formula 1. |
| | W/out natural crust cover | 0.17 | 0.19 | 0.20 | 0.22 | 0.25 | 0.27 | 0.29 | 0.32 | 0.35 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.65 | 0.71 | 0.78 | 0.80 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). When slurry tanks are used as fed-batch storage/digesters, MCF should be calculated according to Formula 1. |

**Table A.5.** Continued

| MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| System | | MCFs by average reporting period temperature (°C) | | | | | | | | | | | | | | | | | | | Source and comments |
| | | Cool | | | | | Temperate | | | | | | | | | | | Warm | | | |
| | | ≤ 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | ≥ 28 | |
| Uncovered anaerobic lagoon | | 0.66 | 0.68 | 0.70 | 0.71 | 0.73 | 0.74 | 0.75 | 0.76 | 0.77 | 0.77 | 0.78 | 0.78 | 0.78 | 0.79 | 0.79 | 0.79 | 0.79 | 0.80 | 0.80 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Uncovered lagoon MCFs vary based on several factors, including temperature, retention time, and loss of volatile solids from the system (through removal of lagoon effluent and/or solids). |
| Pit storage below animal confinements | < 1 month | 0.03 | | | | | 0.03 | | | | | | | | | | | 0.03 | | | Judgment of IPCC Expert Group in combination with Moller et al. (2004) and Zeeman (1994). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions. When pits used as fed-batch storage/digesters, MCF should be calculated according to Formula 1. |
| | > 1 month | 0.19 | 0.19 | 0.20 | 0.22 | 0.25 | 0.27 | 0.29 | 0.32 | 0.35 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.65 | 0.71 | 0.78 | 0.80 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions. When pits used as fed-batch storage/digesters, MCF should be calculated according to Formula 1. |

**Table A.5**. Continued

| MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **System** | | **MCFs by average reporting period temperature (°C)** | | | | | | | | | | | | | | | | | | | **Source and comments** |
| | | **Cool** | | | | | **Temperate** | | | | | | | | | | | **Warm** | | | |
| | | **≤ 10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** | **27** | **≥ 28** | |
| Anaerobic digester | | 0.0-1.00 | | | | | 0.0-1.00 | | | | | | | | | | | 0.0-1.00 | | | Should be subdivided in different categories, considering amount of recovery of the biogas, flaring of the biogas and storage after digestion. Calculation with Formula 1. |
| Burned for fuel | | 0.10 | | | | | 0.10 | | | | | | | | | | | 0.10 | | | Judgment of IPCC Expert Group in combination with Safley et al. (1992). |
| Cattle and Swine deep bedding | < 1 month | 0.03 | | | | | 0.03 | | | | | | | | | | | 0.30 | | | Judgment of IPCC Expert Group in combination with Moller et al. (2004). Expect emissions to be similar, and possibly greater, than pit storage, depending on organic content and moisture content. |
| Cattle and Swine deep bedding (cont.) | > 1 month | 0.17 | 0.19 | 0.20 | 0.22 | 0.25 | 0.27 | 0.29 | 0.32 | 0.35 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.65 | 0.71 | 0.78 | 0.90 | Judgment of IPCC Expert Group in combination with Mangino et al. (2001). |
| Composting - In-vessel[a] | | 0.005 | | | | | 0.005 | | | | | | | | | | | 0.005 | | | Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are less than half of solid storage. Not temperature dependant. |
| Composting - Static pile[a] | | 0.005 | | | | | 0.005 | | | | | | | | | | | 0.005 | | | Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are less than half of solid storage. Not temperature dependant. |

**Table A.5.** Continued

| | | | | |
|---|---|---|---|---|
| Composting - Intensive windrow[a] | 0.005 | 0.01 | 0.015 | Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are slightly less than solid storage. Less temperature dependant. |
| Composting – Passive windrow[a] | 0.005 | 0.01 | 0.015 | Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are slightly less than solid storage. Less temperature dependant. |
| Aerobic treatment | 0.00 | 0.00 | 0.00 | MCFs are near zero. Aerobic treatment can result in the accumulation of sludge which may be treated in other systems. Sludge requires removal and has large VS values. It is important to identify the next management process for the sludge and estimate the emissions from that management process if significant. |
| a Composting is the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production. | | | | |

**Table A.6.** Biogas Destruction Efficiency Default Values by Destruction Device

If available, the actual source test results for the measured methane destruction efficiency must be used in place of the default methane destruction efficiency. Otherwise, the Offset Project Operator or Authorized Project Designee must use the default methane destruction efficiencies provided below.

| Biogas Destruction Device | Biogas Destruction Efficiency (BDE) |
|---|---|
| Open Flare | 0.96 |
| Enclosed Flare | 0.995 |
| Lean-burn Internal Combustion Engine | 0.936 |
| Rich-burn Internal Combustion Engine | 0.995 |
| Boiler | 0.98 |
| Microturbine or large gas turbine | 0.995 |
| Upgrade and use of gas as CNG/LNG fuel | 0.95 |
| Upgrade and injection into natural gas transmission and distribution pipeline | 0.98 |
| Direct pipeline to an end-user | Per corresponding destruction device |

**Table A.7.** CO2 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) | $1.028 \times 10^{-3}$ | 53.02 | 0.055 |
| **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 |
| 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 |
| **Other fuels (solid)** | **MMBtu / short ton** | **kg $CO_2$ / MMBtu** | **kg $CO_2$ / short ton** |
| Municipal Solid Waste | 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 | $0.092 \times 10^{-3}$ | 274.32 | 0.025 |
| Coke Oven Gas | $0.599 \times 10^{-3}$ | 46.85 | 0.028 |
| Propane Gas | $2.516 \times 10^{-3}$ | 61.46 | 0.155 |
| Fuel Gas | $1.388 \times 10^{-3}$ | 59.00 | 0.082 |
| **Biomass Fuels (solid)** | **MMBtu / short ton** | **kg CO2 / 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 CO2 / MMBtu** | **kg $CO_2$ / scf** |
| Biogas (Captured methane) | 0.841 x 10-3 | 52.07 | 0.044 |
| **Biomass Fuels (liquid)** | **MMBtu / gallon** | **kg CO2 / 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 |

**Table A.8.** CO2 Electricity Emission Factors

| eGRID subregion acronym | eGRID subregion name | Annual output emission rates | |
|---|---|---|---|
| | | (lb $CO_2$/MWh) | (metric ton $CO_2$/MWh) |
| AKGD | ASCC Alaska Grid | 1,256.87 | 0.570 |
| AKMS | ASCC Miscellaneous | 448.57 | 0.203 |
| AZNM | WECC Southwest | 1,177.61 | 0.534 |
| CAMX | WECC California | 610.82 | 0.277 |
| ERCT | ERCOT All | 1,218.17 | 0.553 |
| FRCC | FRCC All | 1,196.71 | 0.543 |
| HIMS | HICC Miscellaneous | 1,330.16 | 0.603 |
| HIOA | HICC Oahu | 1,621.86 | 0.736 |
| MROE | MRO East | 1,610.80 | 0.731 |
| MROW | MRO West | 1,536.36 | 0.697 |
| NEWE | NPCC New England | 722.07 | 0.328 |
| NWPP | WECC Northwest | 842.58 | 0.382 |
| NYCW | NPCC NYC/Westchester | 622.42 | 0.282 |
| NYLI | NPCC Long Island | 1,336.11 | 0.606 |
| NYUP | NPCC Upstate NY | 545.79 | 0.248 |
| RFCE | RFC East | 1,001.72 | 0.454 |
| RFCM | RFC Michigan | 1,629.38 | 0.739 |
| RFCW | RFC West | 1,503.47 | 0.682 |
| RMPA | WECC Rockies | 1,896.74 | 0.860 |
| SPNO | SPP North | 1,799.45 | 0.816 |
| SPSO | SPP South | 1,580.60 | 0.717 |
| SRMV | SERC Mississippi Valley | 1,029.82 | 0.467 |
| SRMW | SERC Midwest | 1,810.83 | 0.821 |
| SRSO | SERC South | 1,354.09 | 0.614 |
| SRTV | SERC Tennessee Valley | 1,389.20 | 0.630 |
| SRVC | SERC Virginia/Carolina | 1,073.65 | 0.487 |

**Table A.9.** Volatile Solids Removed Through Solids Separation

| Type of Solids Separation | Volatile Solids Removed (fraction) |
|---|---|
| Gravity | 0.45 |
| Mechanical: | |
| Stationary screen | 0.17 |
| Vibrating screen | 0.15 |
| Screw press | 0.25 |
| Centrifuge | 0.50 |
| Roller drum | 0.25 |
| Belt press/screen | 0.50 |

**Table A.10.** Baseline Assumptions for Greenfield Projects

| Baseline Assumption | Dairy Cattle Operations | | Swine Operations |
|---|---|---|---|
| | >200 Mature Dairy Cows | <200 Mature Dairy Cows | |
| **Anaerobic manure storage system** | Flush system into an anaerobic lagoon with >30 day retention time | Flush system into an anaerobic lagoon with >30 day retention time | Flush system into an anaerobic lagoon with >30 day retention time |
| **Non-anaerobic manure storage system(s)** | Solids storage | Solids Storage | Solids Storage |
| **$MS_L$** | 90% lagoon<br>10% solids storage | 50% lagoon<br>50% solids storage | 95% lagoon<br>5% solids storage |
| **Lagoon cleaning schedule** | Annually, in September | Annually, in September | Annually, in September |

## Appendix B Data Substitution – Quantification Methodology

The methodology presented below may be used only for missing or non-quality assured methane concentration parameters or for missing or non-quality assured flow metering parameters.

(a) The data substitution methodology in table B.1 is allowed for limited circumstances where a project encounters flow rate or methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances.

(1) Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously, except as noted in table B.1.

(2) Substitution may only occur when two other monitored parameters corroborate and document proper functioning of the destruction device and system operation within normal ranges, except as noted in table B.1.

(A) Proper functioning of the destruction device can be documented 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 rate substitution, methane concentrations during the data gap must be consistent with normal operations.

(D) If corroborating parameters fail to meet any of these requirements, no substitution may be employed.

(b) The data substitution methodology in table B.1 is required for all circumstances where a projects encounters project flow rate or methane concentration gaps.

(c) Data substitution is not permissible for equipment that monitors operation of destruction devices and a BDE of 0% must be used for all periods where the operation of the destruction device is not assured.

**Table B.1.** Missing Data

| Duration of Missing Data | Substitution Methodology |
|---|---|
| Less than six hours of one parameter | Use the average of the four hours immediately before and following the outage. |
| Six to 24 hours of one parameter | Use the 90% lower or upper confidence limit of the 24 hours prior to and after the outage, whichever results in greater conservativeness. |
| One to seven days of one parameter | Use the 95% lower or upper confidence limit of the 72 hours prior to and after the outage, whichever results in greater conservativeness. |
| One quarter of methane concentration data | Use the highest or lowest value for the other three quarters of methane concentration data, whichever results in greater conservativeness. This may only be applied once per reporting period. |
| Greater than one week of one parameter or any time with more than one parameter | Take a zero BDE for the device(s) in question with missing data and use the 99% lower or upper confidence limit of all available valid data for the reporting period, whichever results in greater conservativeness. If less than 25% of the data for the reporting period is available, then the single highest or lowest data point must be used. |

California Environmental Protection Agency

AIR RESOURCES BOARD

# Compliance Offset Protocol
# Mine Methane Capture Projects

Capturing and Destroying Methane From
U.S. Coal and Trona Mines

Adopted: April 25, 2014

Note: *All text is new. As permitted by title 2, California Code of Regulations, section 8, for ease of review, underline to indicate adoption has been omitted.*

(This page left intentionally blank)

## Chapter 1. Purpose and Definitions

### 1.1. Purpose

(a) The purpose of the Compliance Offset Protocol Mine Methane Capture Projects (protocol) 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.

(b) AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA);[1] however those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification methodologies and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process. Those sections that are considered to be a quantification methodology are clearly indicated in the title of the chapter or subchapter if only a portion of that chapter is considered part of the quantification methodology of the protocol.

### 1.2. Definitions

(a) For the purposes of this protocol, the following definitions apply:

(1) "Abandoned Underground Mine" means 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 be classified by the Mine Safety and Health Administration (MSHA) as abandoned or abandoned and sealed in order to be eligible for an abandoned mine methane recovery activity.

(2) "Abandoned Mine Methane" or "AMM" means methane released from an abandoned mine.

[1] Health and Safety Code section 38571

(3) “Accuracy” is defined in section 95102 of the Mandatory Reporting Regulation.

(4) “Active Surface Mine” means 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) as active, intermittent, or temporarily idle in order to be eligible for an active surface mine methane drainage activity.

(5) “Active Underground Mine” means a permitted mine usually located several hundred feet below the earth’s surface. A mine must be classified by the Mine Safety and Health Administration (MSHA) as active, intermittent, or temporarily idle in order to be eligible for an active underground mine methane drainage or ventilation air methane activity.

(6) “Basin” is defined in section 95102 of the Mandatory Reporting Regulation.

(7) “Borehole” means a hole made with a drill, augur, or other tool into a coal seam or surrounding strata from which mine gas is extracted.

(8) “Cap-and-Trade Regulation” or “Regulation” means ARB’s regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms as set forth in title 17, California Code of Regulations, chapter 1, subchapter 10, article 5 (commencing with section 95800).

(9) “Coal” is defined in section 95102 of the Mandatory Reporting Regulation.

(10) “Coal Bed Methane” or “CBM” or “Virgin Coal Bed Methane” means methane-rich natural gas drained from coal seams and surrounding strata not disturbed by mining. The extraction, capture, and destruction of virgin coal bed methane are unrelated to mining activities and are not eligible under this protocol.

(11) “Emission Factor” is defined in section 95102 of the Mandatory Reporting Regulation.

(12) “Enclosed Flare” means a flare that is situated in an enclosure for the purposes of safety and accurate measurement of gas combustion. For purposes of this protocol, an enclosed flare is considered a flare.

(13) “End-use Management Option” means a method of methane destruction deemed either eligible or ineligible for the purpose crediting under this protocol.

(14) “Flare” is defined in section 95102 of the Mandatory Reporting Regulation.

(15) “Flooded Mine” or “Flooded Section” means a mine, or section thereof, that is flooded (i.e., filled with water) as a result of the turning off of pumps at time of abandonment and has no detectable freely venting methane emissions. Mines that either pump water due to regulatory or legal requirements or have detectable free standing water shall not be considered flooded provided that they still freely vent methane.

(16) “Flow Meter” is defined in section 95102 of the Mandatory Reporting Regulation.

(17) “Gas Treatment” means 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.

(18) “Gob” means 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.”

(19) “Initial start-up period” means the period between qualifying destruction device installation and project commencement. After the installation of the qualifying destruction device, the Offset Project Operator or Authorized Project Designee may run, tune, and test the system to ensure its operational quality. An initial start-up period must not exceed 9 months.

(20) “Longwall” means 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.

(21) "Mandatory Reporting Regulation" or "MRR" means ARB's regulation establishing the Mandatory Reporting of Greenhouse Gas Emissions set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 2 (commencing with section 95100).

(22) "Methane Drainage System" or "Drainage System" means a system that drains methane from coal or trona seams and/or surrounding rock strata and transports it to a common collection point. Methane drainage systems may comprise multiple methane sources.

(23) "Methane Source" means a methane source type (i.e., ventilation shafts, pre-mining surface wells, pre-mining in-mine boreholes, post-mining gob wells, existing coal bed methane wells that would otherwise be shut-in and abandoned, abandoned wells that are reactivated, and converted dewatering wells) in the aggregate. In this protocol, "methane source" does not refer to any specific ventilation shaft, borehole, or well, but instead refers to all the ventilation shafts, boreholes, and wells of the same type collectively.

(24) "Mine Gas" or "MG" means 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 hyrdocarbons) in addition to methane.

(25) "Mine Methane" or "MM" means methane contained in mineral deposits and surrounding strata that is released as a result of mining operations; the methane portion of mine gas.

(26) "Mine Operator" means 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 protocol, the Mine Operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

(27) "Mine Safety and Health Administration" or "MSHA" means the U.S. federal agency that regulates mine health and safety.

(28) "Mining Activities" means working an area or panel of coal or trona that has been developed and equipped to facilitate mineral extraction and is shown on a mining plan.

(29) "Mountaintop Removal Mining" means a method of surface mining involving the removal of the covering layers of rock and soil at or near the top of a mountain to expose coal seams. Projects which occur at mines that employ mountaintop removal mining are not eligible under this protocol.

(30) "Natural Gas Seep" means an area where natural gas is emitted from overburden and outcrops that connect the mine to the atmosphere.

(31) "Natural Gas Pipeline" or "Pipeline" means a high pressure pipeline transporting saleable quality natural gas offsite to distribution, metering, or regulating stations or directly to customers.

(32) "Non-Qualifying Destruction Device" or "Non-Qualifying Device" means a destruction device that is either operational at the mine prior to offset project commencement, except as specified in section 2.4(b), or used to combust mine methane via an ineligible end-use management option per section 3.4. A destruction device that is operational at the mine prior to offset project commencement is considered a non-qualifying destruction device even if retrofitted thereafter. Methane destroyed by a non-qualifying device must be monitored for quantification of both the baseline and project scenarios.

(33) "Offset Project Expansion" means 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 offset project commencement or connected to a destruction device after offset project commencement. A destruction device is deemed new if it becomes operational after offset project commencement. 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, an Offset Project Operator may choose how to define the

addition. Offset project expansion, unlike the establishment of a new MMC project, will not result in a new offset project commencement date or crediting period. Offset project expansion, unlike the establishment of a new MMC project, allows the Offset Project Operator to submit a single Offset Project Data Report (OPDR) and undergo a single verification for the reporting period.

(34) "Open-pit" means a method of surface mining where coal is exposed by removing the overlying rock. This is also known as open-cut or opencast mining.

(35) "Pre-mining In-mine Boreholes" means a borehole drilled into an unmined seam from within the mine to drain methane from the seam ahead of the advancement of mining. This is also known as horizontal pre-mining boreholes.

(36) "Pre-mining Surface Wells" means a well 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.

(37) "Post-mining Gob Well" or "Gob Well" means a well used to extract or vent methane from the gob. Gob wells may be drilled from the surface or within the mine.

(38) "Project Activity" means a change in mine methane management that leads to a reduction in GHG emissions in comparison to the baseline management and GHG emissions.

(39) "Qualifying Destruction Device" or "Qualifying Device" means a destruction device that was not operational at the mine prior to offset project commencement, except as specified in section 2.4(b), and that was not used to combust mine methane via an ineligible end-use management option per section 3.4. Methane destroyed by a qualifying device must be monitored for quantification of both the baseline and project scenarios.

(40) “Room and Pillar” means 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.

(41) “Sealed,” in reference to an abandoned underground mine, means that existing wells and ventilation shafts are sealed, to some degree, with earthen or concrete seals inhibiting the flow of mine gas into the atmosphere. For purposes of determining baseline emissions under this protocol, the status of an abandoned underground mine (i.e., sealed or venting) must be obtained, if available, from a state agency with information on abandoned coal mines. If status is unavailable, an abandoned underground mine is considered sealed if any known entrance into the mine (e.g., portals, ventilation shafts, and methane drainage wells) has been sealed at any time prior to the project commencement date.

(42) “Shut-in” means to close, temporarily, a well capable of production.

(43) “Standard Conditions” or “Standard Temperature and Pressure” or “STP" means, for the purposes of this protocol, 60 degrees Fahrenheit and 14.7 pounds per square inch absolute (1 atm).

(44) “Standard Cubic Foot” or “scf” means, for the purposes of this protocol, 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.

(45) “Strata,” plural of stratum, means the layers of sedimentary rock surrounding a coal seam.

(46) “Surface Mine Methane” or “SMM” means methane contained in mineral deposits and surrounding strata that is released as a result of surface mining operations.

(47) “Thermal Energy” means 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.

(48) “Trona” means a water-bearing sodium carbonate compound mineral that is mined and processed into soda ash or bicarbonate of soda.

(49) “Uncertainty” is defined in section 95102 of the Mandatory Reporting Regulation.

(50) “Uncertainty Deduction” means an adjustment applied to the emission reductions achieved by an abandoned mine methane recovery activity to account for uncertainty related to the use of emission rate decline curves. The purpose of an uncertainty deduction is to ensure that credited emission reductions remain conservative.

(51) “Ventilation Air” or “VA” means the gas emitted from the ventilation system of a mine which originates across the mine workings and contains low concentrations of methane.

(52) “Ventilation Air Methane” or “VAM” means methane contained in ventilation air.

(53) “Ventilation Air Methane Collection System” or “VAM Collection System” means a system that captures the ventilation air methane from the ventilation system.

(54) “Ventilation Shaft” means a vertical passage used to move fresh air underground and/or to remove methane and other gases from an underground mine.

(55) “Ventilation System” means a system of fans 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.

(56) “Venting,” in reference to an abandoned underground mine, means that existing wells and ventilation shafts are left unsealed, allowing air into the mine and methane to escape freely to the atmosphere. For purposes of determining baseline emissions under this protocol, the status of an abandoned underground mine, sealed or venting, must be obtained from a state agency with information on abandoned coal mines. If status is unavailable, an abandoned underground mine is considered venting if no known entrance into the mine (e.g., portals, ventilation shafts, and methane drainage wells) has been sealed at any time prior to the project commencement date.

(57) “Well” means a well drilled for extraction of natural gas from a coal seam, surrounding strata, or mine.

(b) For terms not defined in section 1.2(a), the definitions in section 95802 of the Cap-and-Trade Regulation (Regulation) apply.

(c) For purposes of this protocol, the following acronyms apply:

(1) “AAPG” means American Association of Petroleum Geologists.

(2) “AB 32” means Assembly Bill 32, the Global Warming Solutions Act of 2006.

(3) “acf” means actual cubic feet.

(4) “acfm” means actual cubic feet per minute.

(5) “AMM” means abandoned mine methane.

(6) “APA” means Administrative Procedure Act.

(7) “ARB” means the California Air Resources Board.

(8) “ASTM” means the American Society of Testing and Materials.

(9) “atm” means atmosphere in reference to a unit of pressure.

(10) “Btu” means British thermal unit.

(11) “CBM” means coal bed methane.

(12) “$CH_4$” means methane.

(13) “$CO_2$” means carbon dioxide.

(14) “$CO_2e$” means carbon dioxide equivalent.

(15) “d” means day.

(16) “F” means Fahrenheit.

(17) “GHG” means greenhouse gas.

(18) “GWP” means global warming potential.

(19) “h” means hour.

(20) “kg” means kilogram.

(21) “lb” means pound.

(22) “m” means minute.

(23) “MG” means mine gas.

(24) “MM” means mine methane.

(25) “MMBtu” means million British thermal units.

(26) “MMC” means mine methane capture.

(27) “MRR” means Mandatory Reporting Regulation; the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

(28) “Mscf” means thousand standard cubic feet.

(29) “Mscf/d” means thousand standard cubic feet per day.

(30) “MSHA” means Mine Safety and Health Administration.

(31) “MT” means metric ton.

(32) “MWh” means megawatt hour.

(33) “$N_2O$” means nitrous oxide.

(34) “OPDR” means Offset Project Data Report.

(35) “R” means Rankine.

(36) “scf” means standard cubic foot.

(37) “scf/d” means standard cubic feet per day.

(38) “scfm” means standard cubic feet per minute.

(39) “SMM” mean surface mine methane.

(40) “SSR” means GHG sources, sinks, and reservoirs.

(41) “STP” means standard temperature and pressure.

(42) “QA/QC” means quality assurance and quality control.

(43) “VA” means ventilation air.

(44) “VAM” means ventilation air methane.

## Chapter 2. Eligible Activities – Quantification Methodology

This protocol 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 protocol applies to MMC projects that install a VAM collection system and qualifying device to destroy the methane in VA otherwise vented into the atmosphere through the return air shaft(s) as a result of underground coal or trona mining operations.

(a) Methane sources eligible for VAM activities include:

  (1) Ventilation systems; and

  (2) 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.

(b) In order to be considered a qualifying device for the purpose of this protocol, the device must not have been operational at the mine prior to offset project commencement.

(c) At active underground mines, an Offset Project Operator or Authorized Project Designee may operate both VAM and methane drainage activities as a single offset project all sharing the earliest commencement date. Alternatively, the Offset Project Operator or Authorized Project Designee may elect to operate separate offset projects for each activity with unique commencement dates.

(d) If a newly constructed ventilation shaft is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(e) If an existing ventilation shaft that was not connected to a destruction device at time of offset project commencement is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(f) 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.

(g) Ventilation air methane from any ventilation shaft connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

### 2.2. Active Underground Mine Methane Drainage Activities

This protocol 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.

(a) 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:

(1) Pre-mining surface wells;

(2) Pre-mining in-mine boreholes; and

(3) Post-mining gob wells.

(b) In order to be considered a qualifying device for the purpose of this protocol, a methane destruction device for an active underground mine methane drainage activity must not have been operational at the mine prior to offset project commencement and must represent an end-use management option other than natural gas pipeline injection.

(c) At active underground mines, an Offset Project Operator or Authorized Project Designee may operate both VAM and methane drainage activities as a single project all sharing the earliest commencement date. Alternatively, the Offset Project Operator or Authorized Project Designee may elect to operate separate projects for each activity with unique commencement dates.

(d) If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(e) If an existing well/borehole that was not connected to a destruction device at time of offset project commencement is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(f) 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.

(g) Mine methane from any well or borehole connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

(h) To be eligible for crediting under this protocol, MMC projects at active underground mines must not:

  (1) 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 3.5; or

  (2) Use $CO_2$, steam, or any other fluid/gas to enhance mine methane drainage.

### 2.3. Active Surface Mine Methane Drainage Activities

This protocol 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.

(a) 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:

  (1) Pre-mining surface wells;

  (2) Pre-mining in-mine boreholes;

  (3) Existing CBM wells that would otherwise be shut-in and abandoned as a result of encroaching mining;

  (4) Abandoned wells that are reactivated; and

  (5) Converted dewatering wells.

(b) In order to be considered a qualifying device for the purpose of this protocol, a methane destruction device for an active surface mine methane drainage activity must not have been operational at the mine prior to offset project commencement.

(c) If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(d) If an existing well/borehole that was not connected to a destruction device at time of offset project commencement is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(e) 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.

(f) SMM from any well or borehole connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

(g) To be eligible for crediting under this protocol, MMC projects at active surface mines must not:

    (1) Account for virgin CBM extracted from wells outside the extents of the mine according to the mine plan or from outside the methane source boundaries as described in section 3.5;

    (2) Use $CO_2$, steam, or any other fluid/gas to enhance mine methane drainage; or

    (3) Occur at mines that employ mountaintop removal mining methods.

### 2.4. Abandoned Underground Mine Methane Recovery Activities

This protocol 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.

(a) Methane drainage systems must consist of one, or a combination of, the following methane sources:

    (1) Pre-mining surface wells drilled into the mine during active mining operations;

(2) Pre-mining in-mine boreholes drilled into the mine during active mining operations;

(3) Post-mining gob wells drilled into the mine during active mining operations; and

(4) Surface wells drilled after the cessation of active mining operations.

(b) In order to be considered a qualifying device for the purpose of this protocol, a methane destruction device for an abandoned underground mine methane recovery activity must not have been operational at the mine prior to offset project commencement 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.

(c) Abandoned underground mine methane recovery activities at multiple mines with multiple mine operators may report and verify together as a single project per the requirements of section 95977 of the Regulation if they meet the following criteria:

(1) A single Offset Project Operator is identified and emission reductions achieved by the project will be credited to that Offset Project Operator.

(2) The methane recovered from the mines is metered at a centralized point prior to being sent to a destruction device.

(3) The Offset Project Operator meets all monitoring, reporting, and verification requirements in chapters 6, 7, and 8.

(4) Offset projects at all mines are in compliance with regulations per section 3.8. If any mine is found to be out of compliance, no emission reductions will be credited to the project for the reporting period even if achieved by one of the other mines found to be in compliance.

(d) 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 3.5(d)(4).

(e) If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project

Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(f) If an existing well/borehole that was not connected to a destruction device at time of offset project commencement is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or list the addition as a new MMC project.

(g) 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.

(h) AMM from any well or borehole connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

(i) To be eligible for crediting under this protocol, MMC projects at abandoned underground mines must not:

  (1) Account for virgin CBM 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 3.5;

  (2) Use $CO_2$, steam, or any other fluid/gas to enhance mine methane drainage; or

  (3) Occur at flooded mines or in flooded sections of mines.

## Chapter 3. Eligibility

In addition to the offset project eligibility criteria and regulatory program requirements set forth in subarticle 13 of the Regulation, mine methane capture offset projects must adhere to the eligibility requirements below.

### 3.1. General Eligibility Requirements

(a) Offset projects that use this protocol must:

  (1) Involve the installation and operation of a device, or set of devices, associated with the capture and destruction of mine methane;

(2) Capture mine methane that would otherwise be emitted to the atmosphere; and

(3) Destroy the captured mine methane through an eligible end-use management option per section 3.4.

(b) Offset Project Operators or Authorized Project Designees that use this protocol must:

(1) Provide the listing information required by section 95975 of the Regulation and section 7.1;

(2) Monitor GHG emission sources within the offset project boundary as delineated in chapter 4 per the requirements of chapter 6;

(3) Quantify GHG emission reductions per chapter 5;

(4) Prepare and submit OPDRs for each reporting period that include the information requirements in section 7.2; and

(5) Obtain offset verification services from an ARB-accredited offset verification body in accordance with section 95977 of the Regulation and chapter 8.

### 3.2. Location

(a) Only projects located in the United States are eligible under this protocol.

(b) Offset projects situated on the following categories of land are only eligible under this protocol if they meet the requirements of this protocol and the Regulation, including the waiver of sovereign immunity requirements of section 95975(l) of the Regulation:

(1) Land that is owned by, or subject to an ownership or possessory interest of a Tribe;

(2) Land that is “Indian lands” of a Tribe, as defined by 25 U.S.C. §81(a)(1); or

(3) Land that is owned by any person, entity, or Tribe, within the external borders of such Indian lands.

(c) Projects must take place at either:

(1) An active underground or surface mine permitted for coal or trona mining by an appropriate state or federal agency and classified by MSHA as active, intermittent, or temporarily idle; or

(2) An abandoned underground coal mine classified by MSHA as abandoned or abandoned and sealed.

(d) Mines located on federal lands are eligible for implementation of MMC projects.

### 3.3. Offset Project Operator or Authorized Project Designee

(a) The Offset Project Operator or Authorized Project Designee is responsible for project listing, monitoring, reporting, and verification.

(b) The Offset Project Operator or Authorized Project Designee must submit the information required by subarticle 13 of the Regulation and in chapter 7.

(c) The Offset Project Operator must have legal authority to implement the offset project.

(d) The Offset Project Operator must be:

(1) The mine operator as defined in section 1.2(a)(26); or

(2) The entity that owns or leases the equipment used to capture or destroy mine methane.

### 3.4. Additionality

Offset projects must meet the additionality requirements set out in section 95973(a)(2) of the Regulation, in addition to the requirements in this protocol. 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 3.4.1 and the Performance Standard Evaluation in section 3.4.2.

### 3.4.1. Legal Requirement Test

(a) Emission reductions achieved by an MMC project must exceed those required by any law, regulation, or legally binding mandate as required in sections 95973(a)(2)(A) and 95975(n) of the Regulation.

(b) The following legal requirement test applies to all MMC projects:

(1) If no law, regulation, or legally binding mandate requiring the destruction of methane at the mine at which the project is located exists, 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 protocol.

(2) If any law, regulation, or legally binding mandate requiring the destruction of methane at the mine at which the project is located exists, only emission reductions resulting from the capture and destruction of mine methane 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.

### 3.4.2. Performance Standard Evaluation

(a) Emission reductions achieved by an MMC project must exceed those likely to occur in a conservative business-as-usual scenario.

(b) The performance standard evaluation is satisfied if the following requirements are met, on the basis of activity type:

(1) Active Underground Mine VAM Activities

(A) Destruction of VAM via any end-use management option 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 protocol.

(2) Active Underground Mine Methane Drainage Activities

(A) Destruction of extracted mine methane via any end-use management option except as described in 3.4.2(b)(2)(B) 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 protocol.

(B) Pipeline injection of mine methane extracted from methane drainage systems at active underground mines is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol.

(3) Active Surface Mine Methane Drainage Activities

(A) Destruction of extracted mine methane via any end-use management option 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 protocol.

(4) Abandoned Underground Mine Methane Recovery Activities

(A) Destruction of extracted mine methane via any end-use management option except as described in 3.4.2(b)(4)(B) 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 protocol.

(B) Pipeline injection of mine methane recovered at abandoned underground mines that also injected mine methane into a natural gas pipeline for off-site consumption while active is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol.

### 3.5. Methane Source Boundaries

(a) The methane destroyed for the purpose of reducing mine methane emissions under this protocol must be methane that would otherwise be emitted into the atmosphere during the normal course of mining activities.

(b) To ensure that virgin coal bed methane is excluded from the destroyed mine methane accounted for in this protocol, physical boundaries must be placed on the source of the methane.

(c) Methane from a mine's ventilation and drainage systems must be collected from within the mine extents according to an up-to-date mine plan.

(d) Additional physical boundaries on the basis of activity type are as follows:

(1) Active underground mine ventilation air methane activities may account for:

(A) All destroyed methane contained in VA collected from a mine ventilation system; and

(B) All destroyed mine methane contained in mine gas extracted from a methane drainage system used to supplement VA.

(2) Active underground mine methane drainage activities may account for:

(A) Destroyed 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 pre-mining in-mine boreholes; and

(B) All destroyed mine methane contained in mine gas extracted through gob wells.

(3) Active surface mine methane drainage activities may account for destroyed 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, pre-mining in-mine boreholes, existing coal bed 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.

(4) Abandoned underground mine methane recovery activities may account for:

(A) Destroyed abandoned 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 pre-mining in-mine boreholes drilled during active mining operations;

(B) Destroyed abandoned mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mine seam through newly drilled surface wells; and

(C) Destroyed abandoned mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mined seam through existing post-mining gob wells.

### 3.6. Offset Project Commencement

(a) For this protocol, offset project commencement is defined as the date at which the offset project’s mine methane capture and destruction equipment becomes operational. Equipment is considered operational on the date at which the system begins capturing and destroying methane gas upon completion of an initial start-up period.

(b) Per section 95973(a)(2)(B) of the Regulation, compliance offset projects must have an offset project commencement date after December 31, 2006.

### 3.7. Project Crediting Period

The crediting period for this protocol is ten reporting periods.

### 3.8. Regulatory Compliance

(a) An offset project must meet the regulatory compliance requirements set forth in section 95973(b) of the Regulation.

## Chapter 4. Offset Project Boundary – Quantification Methodology

The offset project boundary delineates the GHG emission 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

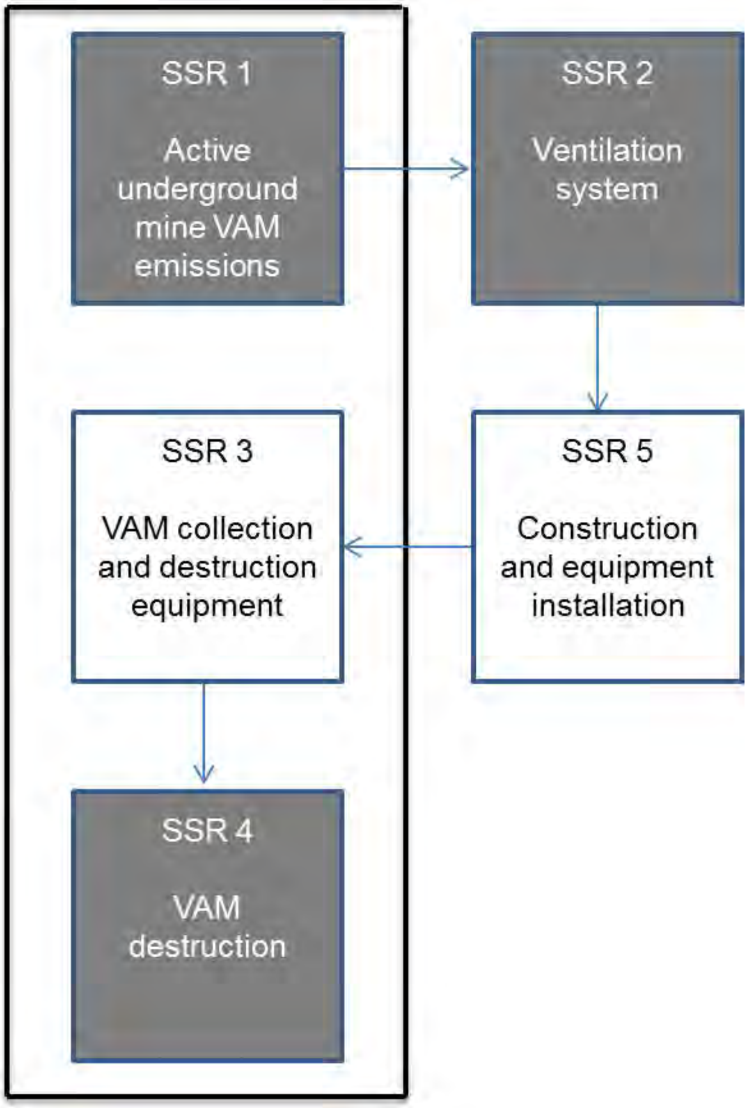
(a) Figure 4.1 illustrates the offset project boundary for active underground mine VAM activities, indicating which SSRs are included or excluded from the offset project boundary.

  (1) All SSRs within the bold line are included and must be accounted for under this protocol.

  (2) SSRs in shaded boxes are relevant to the baseline and project emissions.

  (3) SSRs in unshaded boxes are relevant only to the project emissions.

**Figure 4.1. Illustration of the offset project boundary for active underground mine VAM activities**



(b) Table 4.1 lists the SSRs for active underground mine VAM activities, indicating which gases are included or excluded from the offset project boundary.

**Table 4.1. List of the greenhouse gas sinks, sources, and reservoirs for active underground mine VAM activities**

| SSR | Description | GHG | Baseline (B) or Project (P) | Included/ Excluded |
|---|---|---|---|---|
| 1 | Emissions from the venting of VAM through mine ventilation system | $CH_4$ | B, P | Included |
| 2 | Emissions resulting from energy consumed to operate mine ventilation system | $CO_2$ | n/a | Excluded |
| | | $CH_4$ | n/a | Excluded |
| | | $N_2O$ | n/a | Excluded |
| 3 | 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 | 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 | 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

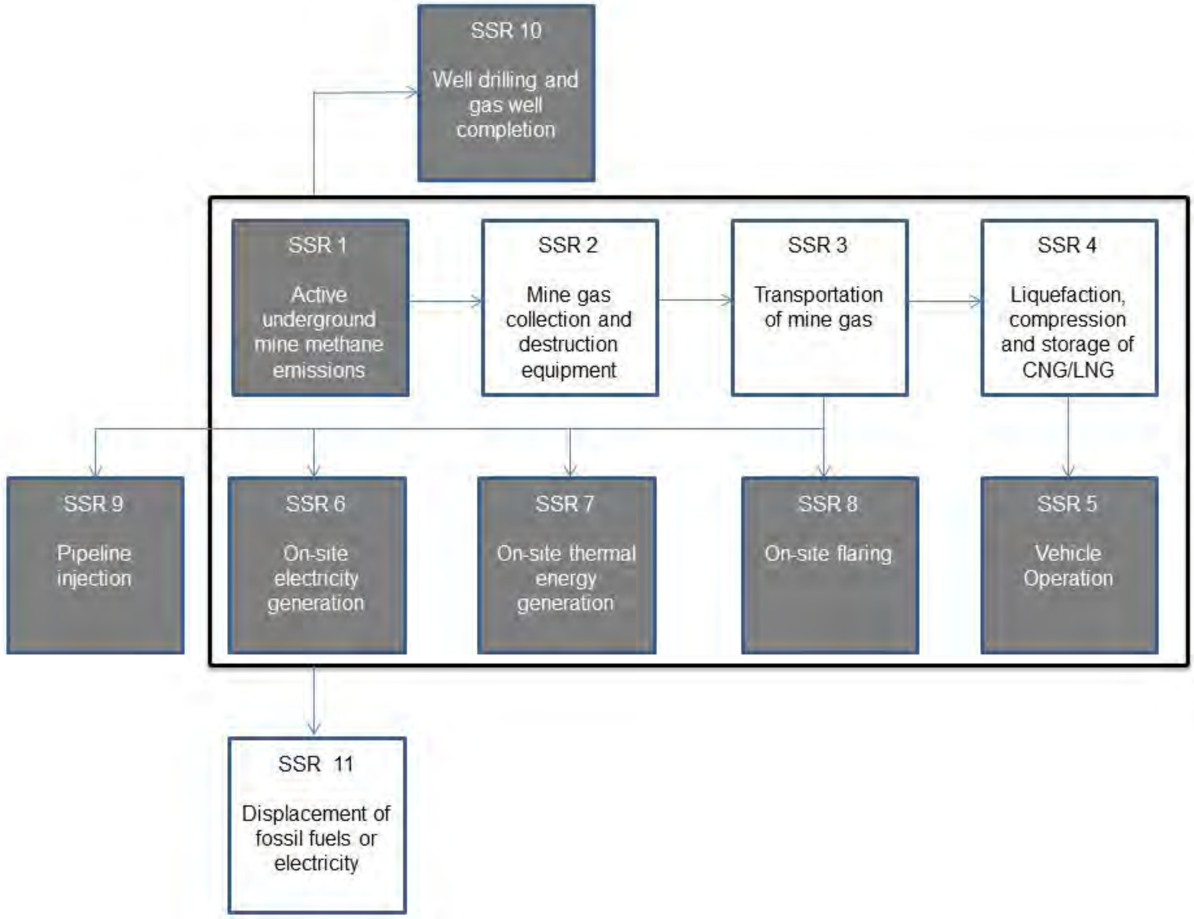
(a) Figure 4.2 illustrates the offset project boundary for active underground mine methane drainage activities, indicating which SSRs are included or excluded from the offset project boundary.

(1) All SSRs within the bold line are included and must be accounted for under this protocol.

(2) SSRs in shaded boxes are relevant to the baseline and project emissions.

(3) SSRs in unshaded boxes are relevant only to the project emissions.

**Figure 4.2. Illustration of the offset project boundary for active underground mine methane drainage activities**



(b) Table 4.2 lists the identified SSRs for active underground mine methane drainage activities, indicating which gases are included or excluded from the offset project boundary.

**Table 4.2. List of identified greenhouse gas sinks, sources, and reservoirs for active underground mine methane drainage activities**

| SSR | Description | GHG | Relevant to Baseline (B) or Project (P) | Included/ Excluded |
|---|---|---|---|---|
| 1 | Emissions from the venting of mine methane extracted through methane drainage system | $CH_4$ | B, P | Included |
| 2 | 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 | 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 | Emissions resulting from energy consumed to operate additional equipment used to liquefy, compress, or store methane for vehicle use. | $CO_2$ | P | Included |
| | | $CH_4$ | n/a | Excluded |
| | | $N_2O$ | n/a | Excluded |
| | Fugitive emissions from operation of additional equipment used to liquefy, compress, or store methane for vehicle use | $CH_4$ | n/a | Excluded |
| 5 | Emissions resulting from methane combustion during vehicle operation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during vehicle operation | $CH_4$ | B, P | Included |
| 6 | Emissions resulting from methane combustion during on-site electricity generation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during on-site electricity generation | $CH_4$ | B, P | Included |

| | | | | |
|---|---|---|---|---|
| 7 | Emissions resulting from methane combustion during on-site thermal energy generation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during on-site thermal energy generation | $CH_4$ | B, P | Included |
| 8 | Emissions resulting from methane combustion during on-site flaring | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during flaring | $CH_4$ | B, P | Included |
| 9 | Emissions resulting from methane combustion resulting from pipeline injection | $CO_2$ | n/a | Excluded |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from the incomplete methane combustion resulting from pipeline injection | $CH_4$ | n/a | Excluded |
| 10 | 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 | 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

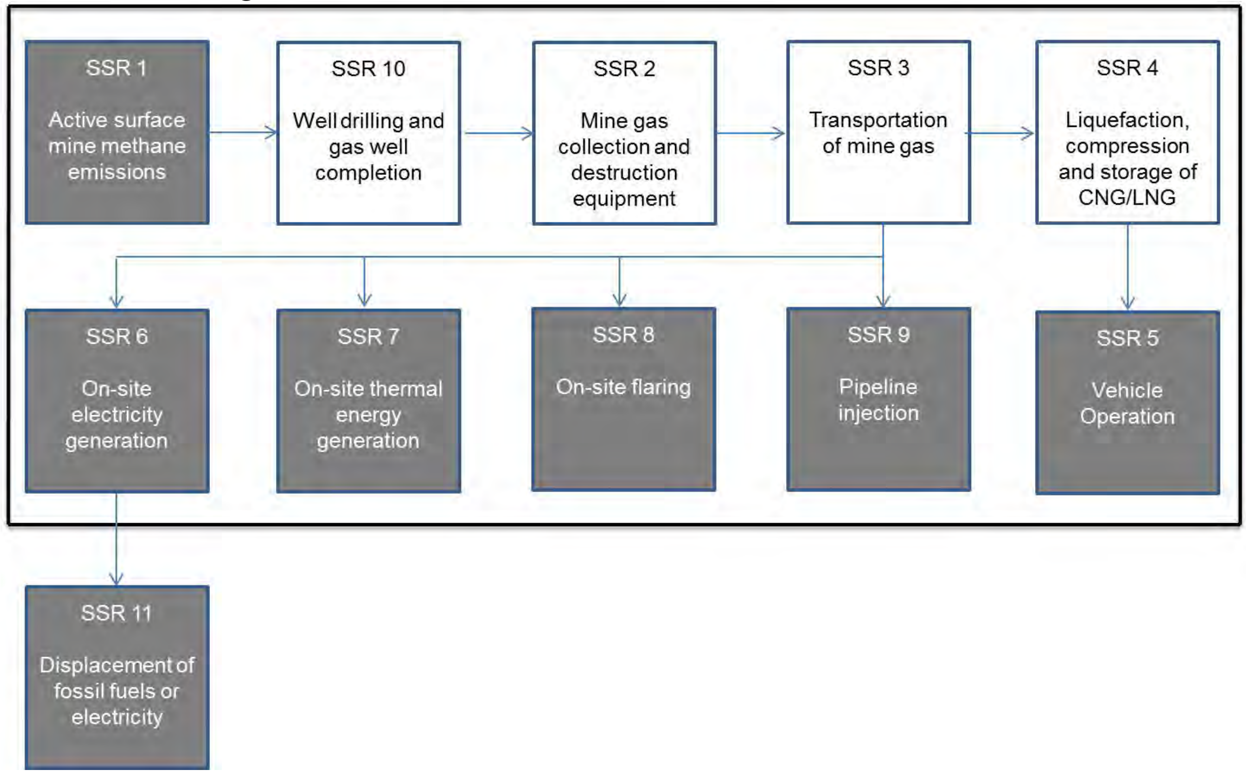
(a) Figure 4.3 illustrates the offset project boundary for active surface mine methane drainage activities, indicating which SSRs are included or excluded from the offset project boundary.

(1) All SSRs within the bold line are included and must be accounted for under this protocol.

(2) SSRs in shaded boxes are relevant to the baseline and project emissions.

(3) SSRs in unshaded boxes are relevant only to the project emissions.

**Figure 4.3. Illustration of the offset project boundary for active surface mine methane drainage activities**




(b) Table 4.3 lists the SSRs for active surface mine methane drainage activities, indicating which gases are included or excluded from the offset project boundary.

**Table 4.3. List of the greenhouse gas sinks, sources, and reservoirs for active surface mine methane drainage activities**

| SSR | Description | GHG | Relevant to Baseline (B) or Project (P) | Included/ Excluded |
|---|---|---|---|---|
| 1 | Emissions from the venting of mine methane during the mining process | $CH_4$ | B, P | Included |
| 2 | 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 | 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 | Emissions resulting from energy consumed to operate additional equipment used to liquefy, compress, or store methane for vehicle use. | $CO_2$ | P | Included |
| | | $CH_4$ | n/a | Excluded |
| | | $N_2O$ | n/a | Excluded |
| | Fugitive emissions from operation of additional equipment used to liquefy, compress, or store methane for vehicle use | $CH_4$ | n/a | Excluded |
| 5 | Emissions resulting from methane combustion during vehicle operation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during vehicle operation | $CH_4$ | B, P | Included |
| 6 | Emissions resulting from methane combustion during on-site electricity generation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during on-site electricity generation | $CH_4$ | B, P | Included |
| 7 | Emissions resulting from methane combustion during on-site thermal energy generation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during on-site thermal energy generation | $CH_4$ | B, P | Included |
| 8 | Emissions resulting from methane combustion during on-site flaring | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during flaring | $CH_4$ | B, P | Included |
| 9 | Emissions resulting from methane combustion resulting from pipeline injection | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from the incomplete methane combustion resulting from pipeline injection | $CH_4$ | B, P | Included |
| 10 | 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 | 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

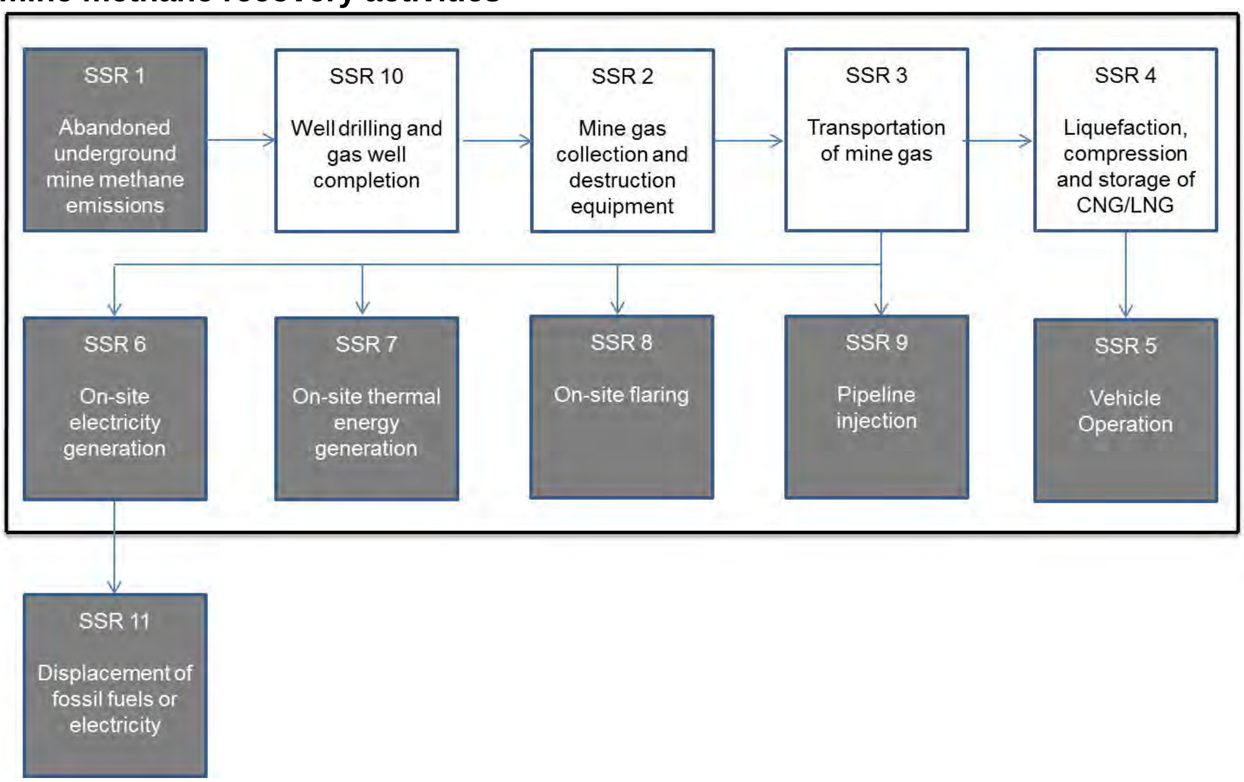
(a) Figure 4.4 illustrates the offset project boundary for abandoned underground mine methane recovery activities, indicating which SSRs are included or excluded from the offset project boundary.

(1) All SSRs within the bold line are included and must be accounted for under this protocol.

(2) SSRs in shaded boxes are relevant to the baseline and project emissions.

(3) SSRs in unshaded boxes are relevant only to the project emissions.

**Figure 4.4. Illustration of the offset project boundary for abandoned underground mine methane recovery activities**




(b) Table 4.4 lists the SSRs for abandoned underground mine methane recovery activities, indicating which gases are included or excluded from the offset project boundary.

**Table 4.4. List of the greenhouse gas sinks, sources, and reservoirs for abandoned underground mine methane recovery activities**

| SSR | Description | GHG | Relevant to Baseline (B) or Project (P) | Included/ Excluded |
|---|---|---|---|---|
| 1 | Emissions of mine methane liberated after the conclusion of mining operations | $CH_4$ | B, P | Included |
| 2 | 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 | 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 | Emissions resulting from energy consumed to operate equipment used to liquefy, compress, or store methane for vehicle use. | $CO_2$ | P | Included |
| | | $CH_4$ | 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 | Emissions resulting from methane combustion during vehicle operation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during vehicle operation | $CH_4$ | B, P | Included |
| 6 | Emissions resulting from methane combustion during on-site electricity generation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during on-site electricity generation | $CH_4$ | B, P | Included |
| 7 | Emissions resulting from methane combustion during on-site thermal energy generation | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from incomplete methane combustion during on-site electricity generation | $CH_4$ | B, P | Included |
| 8 | Emissions resulting from methane combustion during on-site flaring | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from | $CH_4$ | B, P | Included |

| | | | | |
|---|---|---|---|---|
| | incomplete methane combustion during flaring | | | |
| 9 | Emissions resulting from methane combustion resulting from pipeline injection | $CO_2$ | B, P | Included |
| | | $N_2O$ | n/a | Excluded |
| | Emissions resulting from the incomplete methane combustion resulting from pipeline injection | $CH_4$ | B, P | Included |
| 10 | 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 | 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 |

## Chapter 5. Quantifying GHG Emission Reductions – Quantification Methodology

(a) GHG emission reductions from an MMC project are quantified by comparing actual project emissions to project baseline emissions at the mine.

(b) Offset Project Operators and Authorized Project Designees must use the activity type-specific calculation methods provided in this protocol to determine baseline and project GHG emissions.

(c) GHG emission reductions must be quantified over a consecutive twelve month period. The length of time over which GHG emission reductions are quantified is called the "reporting period."

(d) 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).

(e) 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.

(f) Global warming potential values must be determined consistent with the definition of Carbon Dioxide Equivalent in MRR section 95102(a).

### 5.1. Active Underground Mine Ventilation Air Methane Activities

(a) 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 5.1.

| **Equation 5.1: GHG Emission Reductions** | | |
|---|---|---|
| *ER = BE – PE* | | |
| *Where,* | | |
| *ER* | = | Emission reductions achieved by the project during the reporting period (MT $CO_2$e) |
| *BE* | = | Baseline emissions during the reporting period (MT $CO_2$e) |
| *PE* | = | Project emissions during the reporting period (MT $CO_2$e) |

#### 5.1.1. Quantifying Baseline Emissions

(a) 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 4.1 and by using equation 5.2.

| **Equation 5.2: Baseline Emissions** | | |
|---|---|---|
| $BE = BE_{MD} + BE_{MR}$ | | |
| *Where,* | | |
| *BE* | = | Baseline emissions during the reporting period (MT $CO_2$e) |
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2$e) |
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere during the reporting period (MT $CO_2$e) |

(b) Baseline emissions from the destruction of methane ($BE_{MD}$) must be quantified using equation 5.3.

(c) $BE_{MD}$ must include the estimated $CO_2$ emissions from the destruction of VAM by non-qualifying devices.

(d) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

| **Equation 5.3: Baseline Emissions from Destruction of Methane** |
|---|
| $BE_{MD} = \sum_i MD_{B,i} \times CEF_{CH4}$ |
| *Where,* |

| | | |
|---|---|---|
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2e$) |
| $i$ | = | Use of methane (oxidation or alternative end-use) by non-qualifying destruction devices |
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2e$/MT $CH_4$) |

(e) The amount of methane that would have been destroyed by non-qualifying destruction devices ($MD_{B,i}$) must be quantified using equation 5.4.

(f) For the purpose of baseline quantification, only non-qualifying destruction devices that were operating during the year prior to offset project commencement should be taken into account.

(g) The volume or mass of VA that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be determined by calculating and comparing:

(1) The volume or mass of VA sent to non-qualifying destruction devices during the current reporting period, adjusted for temperature and pressure using equation 5.11, if applicable;

(2) The volume or mass of VA sent to non-qualifying destruction devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using equation 5.11, if applicable, and averaged according to the length of the reporting period; and

(3) The volume or mass of VA sent to non-qualifying destruction devices during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using equation 5.11, if applicable, and averaged according to the length of the reporting period.

(h) The largest of the three quantities determined in sections 5.1.1(g)(1)-(3) must be used for the volume of ventilation air that would have been sent to a non-qualifying device for destruction through use i during the reporting period in the baseline scenario ($VA_{B,i}$) in equations 5.4 and 5.5.

(i) If using a quantity for $VA_{B,i}$ determined by section 5.1.1(g)(1), data for ventilation air flow rate ($VA_{flow,t}$), methane concentration of ventilation air ($C_{CH4,t}$), methane concentration of exhaust gas ($C_{CH4,exhaust,t}$), average flow rate of cooling air ($CA_{flow,i,y}$), hours of destruction device operation (y), volume of mine gas sent for destruction with ventilation air ($MG_{SUPP,i}$), and methane concentration of mine gas ($C_{CH4,MG}$) must be monitored for the non-qualifying destruction devices and used in equations 5.4 and 5.5.

(j) If using a quantity for $VA_{B,i}$ determined by section 5.1.1(g)(2) or 5.1.1(g)(3), historical data for ventilation air flow rate ($VA_{flow,t}$), methane concentration of ventilation air ($C_{CH4,t}$), methane concentration of exhaust gas ($C_{CH4,exhaust,t}$), average flow rate of cooling air ($CA_{flow,i,y}$), hours of operation (y), volume of mine gas sent for destruction with ventilation air ($MG_{SUPP,i}$), and methane concentration of mine gas ($C_{CH4,MG}$) must be used in equations 5.4 and 5.5, if available.

(k) If using a quantity for $VA_{B,i}$ determined by section 5.1.1(g)(2) or 5.1.1(g)(3), and historical data for ventilation air flow rate ($VA_{flow,t}$), methane concentration of ventilation air ($C_{CH4,t}$), methane concentration of exhaust gas ($C_{CH4,exhaust,t}$), average flow rate of cooling air ($CA_{flow,i,y}$), and mine gas methane concentration ($C_{CH4,MG}$) are not available, the highest single-hour average flow rates and methane concentrations during the reporting period must be used in place of historical data.

(l) If using a quantity for $VA_{B,i}$ determined by section 5.1.1(g)(2) or 5.1.1(g)(3), and historical data for hours of operation (y) is not available, the highest number of operational hours for any qualifying or non-qualifying destruction device during the reporting period must be used in place of historical data.

(m) If using a quantity for $VA_{B,i}$ determined by section 5.1.1(g)(2) or 5.1.1(g)(3), and historical data for volume of mine gas sent for destruction with ventilation air ($MG_{SUPP,i}$) is not available, the largest volume of mine gas sent to any qualifying or non-qualifying destruction device during the reporting period must be used in place of historical data.

(n) If cooling air was added to the destruction device after the point of metering for VA, this must be accounted for with term $CA_{flow,i,y}$ in equation 5.4. If no cooling air was added, then $CA_{flow,i,y} = 0$.

(o) If the flow rate of cooling air was metered, then the average metered data flow rate must be used for the flow rate. If the flow rate was not metered, the maximum capacity of the cooling air intake system must be used for the flow rate.

**Equation 5.4: Methane Destroyed in Baseline**

$$MD_{B,i} = (VA_{B,i} \times C_{CH4} \times 0.0423 \times 0.000454 - BE_{NO,i})$$

*Where,*

| | | |
|---|---|---|
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period; calculated separately for each destruction device (MT $CH_4$) |
| $i$ | = | Use of methane (oxidation or alternative end-use) by non-qualifying destruction devices |
| $VA_{B,i}$ | = | Volume of ventilation air that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of captured ventilation air that would have been sent to non-qualifying destruction devices during the reporting period (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |
| $BE_{NO,i}$ | = | Baseline emissions of non-oxidized methane that would have been emitted as a result of incomplete oxidation of the ventilation air stream during the reporting period (MT $CH_4$) |

With:

$$C_{CH4} = \frac{\sum_t (VA_{flow,t} \times C_{CH4,t})}{\sum_t VA_{flow,t}}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Hourly average methane concentration of ventilation air sent to a destruction device (scf $CH_4$/scf) |
| $VA_{flow,t}$ | = | Hourly average flow rate of ventilation air sent to a destruction device (scfm) |

And:

$BE_{NO,i}$ = ($VA_{B,i}$ + $\sum_{y}$ $CA_{flow,i,y}$ x 60) x $C_{CH4,exhaust,i}$ x 0.0423 x 0.000454

*Where,*

| | | |
|---|---|---|
| $y$ | = | Hours during which the destruction device would have been operational during reporting period (h) |
| $CA_{flow,i,y}$ | = | Hourly average flow rate of cooling air that would have been sent to a destruction device after the metering point of the ventilation air stream during period y (scfm) |
| 60 | = | Number of minutes in an hour |
| $C_{CH4,exhaust,i}$ | = | Weighted average of measured methane concentration of exhaust gas that would have been emitted from the destruction device during the reporting period (scf $CH_4$/scf) |

With:

$$C_{CH4,exhaust,i} = \frac{\sum_y \left[\left(\frac{VA_{B,i}}{y} + CA_{flow,i,y} \times 60\right) \times C_{CH4,exhaust,y}\right]}{\sum_y \left(\frac{VA_{B,i}}{y} + CA_{flow,i,y} \times 60\right)}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,exhaust,y}$ | = | Hourly average methane concentration of exhaust gas (scf $CH_4$/scf) |

Methane concentrations and flow rates must be recorded every two minutes with averages calculated at least hourly. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(p) Baseline emissions from the release of methane ($BE_{MR}$) must be quantified using equation 5.5.

(q) $BE_{MR}$ must account for the total amount of methane actually destroyed by all qualifying and non-qualifying devices during the reporting period.

(r) 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 5.5, either as $MG_{SUPP,i}$ if VA flow and MG flow are monitored separately, or through $VA_{P,i}$ if only the resulting enriched flow is monitored.

(s) 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 5.5: Baseline Emissions from Release of Methane**

$$BE_{MR} = \sum_i [(VA_{P,i} \times C_{CH4} - VA_{B,i} \times C_{CH4}) + MG_{SUPP,i} \times C_{CH4,MG}] \times 0.0423 \times 0.000454 \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere during the reporting period (MT $CO_2e$) |
| $i$ | = | Use of methane (oxidation or alternative end-use) by all qualifying and non-qualifying destruction devices |
| $VA_{P,i}$ | = | Volume of ventilation air sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $VA_{B,i}$ | = | Volume of ventilation air that would have sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of captured ventilation air sent to qualifying and non-qualifying destruction devices during the reporting period (scf $CH_4$/scf) |
| $MG_{SUPP,i}$ | = | Volume of mine gas that would have been extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period (scf) |
| $C_{CH4,MG}$ | = | Weighted average of measured methane concentration of captured mine gas that would have been sent with ventilation air to non-qualifying devices for destruction during the reporting period (scf $CH_4$/scf) |
| 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 $CH_4$) |

With:

$$C_{CH4} = \frac{\sum_t (VA_{flow,t} \times C_{CH4,t})}{\sum_t VA_{flow,t}}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Hourly average methane concentration of ventilation air sent to a destruction device (scf $CH_4$/scf) |
| $VA_{flow,t}$ | = | Hourly average flow rate of ventilation air sent to a destruction device (scfm) |

And:

$$C_{CH4MG} = \frac{\sum_t (DV_{MG,t} \times C_{CH4,MG,t})}{\sum_t DV_{MG,t}}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,MG,t}$ | = | Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf $CH_4$/scf) |
| $DV_{MG,t}$ | = | Daily volume of mine gas sent with ventilation air to destruction device (scf) |

Methane concentrations and flow rates must be recorded every two minutes with averages calculated at least hourly. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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

(a) Project emissions must be quantified over a consecutive twelve month period.

(b) 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 4.1 and using equation 5.6.

(c) 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 5.6: Project Emissions**

$$PE = PE_{EC} + PE_{MD} + PE_{UM}$$

*Where,*

| | | |
|---|---|---|
| $PE$ | = | Project emissions during the reporting period (MT $CO_2$e) |
| $PE_{EC}$ | = | Project emissions from energy consumed to capture and destroy methane during the reporting period (MT $CO_2$e) |

| | | |
|---|---|---|
| $PE_{MD}$ | = | Project emissions from destruction of methane during the reporting period (MT $CO_2$e) |
| $PE_{UM}$ | = | Project emissions from uncombusted methane during the reporting period (MT $CO_2$e) |

(d) 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 5.7.

**Equation 5.7: Project Emissions from Energy Consumed to Capture and Destroy Methane**

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1000}$$

*Where,*

| | | |
|---|---|---|
| $PE_{EC}$ | = | Project emissions from energy consumed to capture and destroy methane during the reporting period (MT $CO_2$e) |
| $CONS_{ELEC}$ | = | 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 appendix A (MT $CO_2$e/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 A.1 (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 appendix A (kg $CO_2$/volume) |
| 1/1000 | = | Conversion of kg to metric tons |

(e) Project emissions from the destruction of methane ($PE_{MD}$) must be quantified using equation 5.8.

**Equation 5.8: Project Emissions from Destruction of Methane**

$$PE_{MD} = \sum_{i} MD_{P,i} \times CEF_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $PE_{MD}$ | = | Project emissions from destruction of methane during the reporting period (MT $CO_2e$) |
| $i$ | = | Use of methane (oxidation or alternative end-use) by all qualifying and non-qualifying destruction devices |
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2e$/MT $CH_4$) |

(f) The amount of methane destroyed ($MD_{P,i}$) must be quantified using equation 5.9.

(g) If MG is used to supplement VA, the MG destroyed by the project during the reporting period must be accounted for using equation 5.9 either as $MG_{SUPP,i}$, if VA flow and MG flow are monitored separately, or through $VA_{P,i}$ if only the resulting enriched flow is monitored.

(h) If cooling air was added to the destruction device after the point of metering for VA, this must be accounted for with term $CA_{flow,i,y}$ in equations 5.9 and 5.10. If no cooling air is added, then $CA_{flow,i,y} = 0$.

(i) If the flow rate of cooling air was metered, then the average 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 5.9: Methane Destroyed**

$$MD_{P,i} = (MM_{P,i} - PE_{NO,i})$$

*Where,*

| | | |
|---|---|---|
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period; calculated separately for each destruction device (MT $CH_4$) |
| $i$ | = | Use of methane (oxidation or alternative end-use) by all qualifying and non-qualifying destruction devices |
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $PE_{NO,i}$ | = | Project emissions of non-oxidized methane emitted as a result of incomplete oxidation of the ventilation air stream during the reporting period (MT $CH_4$) |

With:

$$MM_{P,i} = (VA_{P,i} \times C_{CH4} + MG_{SUPP,i} \times C_{CH4,MG}) \times 0.0423 \times 0.000454$$

*Where,*

$VA_{P,i}$ = Volume of ventilation air sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)

$C_{CH4}$ = Weighted average of measured methane concentration of captured ventilation air sent to qualifying and non-qualifying destruction devices during the reporting period; (scf $CH_4$/scf)

$MG_{SUPP,i}$ = Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period (scf)

$C_{CH4,MG}$ = Weighted average of measured methane concentration of captured mine gas sent with ventilation air to qualifying and non-qualifying destruction devices during the reporting period (scf $CH_4$/scf)

0.0423 = Standard density of methane (lb $CH_4$/scf $CH_4$)

0.000454 = MT $CH_4$/lb $CH_4$

With:

$$C_{CH4} = \frac{\sum_t (VA_{flow,t} \times C_{CH4,t})}{\sum_t VA_{flow,t}}$$

*Where,*

$C_{CH4,t}$ = Hourly average methane concentration of ventilation air sent to a destruction device (scf $CH_4$/scf)

$VA_{flow,t}$ = Hourly average flow rate of ventilation air sent to a destruction device (scfm)

And:

$$C_{CH4MG} = \frac{\sum_t (DV_{MG,t} \times C_{CH4,MG,t})}{\sum_t DV_{MG,t}}$$

*Where,*

$C_{CH4,MG,t}$ = Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf $CH_4$/scf)

$DV_{MG,t}$ = Daily volume of mine gas sent with ventilation air to destruction device (scf)

And:

$$PE_{NO,i} = \sum_y (VA_{flow,i,y} \text{ x } 60 + CA_{flow,i,y} \text{ x } 60) \text{ x } C_{CH4,exhaust,i} \text{ x } 0.0423 \text{ x } 0.000454$$

*Where,*

| | | |
|---|---|---|
| $y$ | = | Hours during which destruction device was operational during reporting period (h) |
| $VA_{flow,i,y}$ | = | Hourly average flow rate of ventilation air sent to a device for destruction through use i during the reporting period (scfm) |
| $CA_{flow,i,y}$ | = | Hourly average flow rate of cooling air sent to a destruction device after the metering point of the ventilation air stream during period y (scfm) |
| 60 | = | Number of minutes in an hour |
| $C_{CH4,exhaust,i}$ | = | Weighted average of measured methane concentration of exhaust gas emitted from the destruction device during the reporting period (scf $CH_4$/scf) |

With:

$$C_{CH4,exhaust,i} = \frac{\sum_y \left[\left(VA_{flow,i,y} \times 60 \ + CA_{flow,i,y} \times 60\right) \times \ C_{CH4,exhaust,y}\right]}{\sum_y \left(VA_{flow,i,y} \times 60 + CA_{flow,i,y} \times 60\right)}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,exhaust,y}$ | = | Hourly average methane concentration of exhaust gas (scf $CH_4$/scf) |

Methane concentrations and flow rates must be recorded every two minutes with averages calculated at least hourly. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(k) Project emissions from uncombusted methane ($PE_{UM}$) must be quantified using equation 5.10.

**Equation 5.10: Project Emissions from Uncombusted Methane**

$$PE_{UM} = \sum_i PE_{NO,i} \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $PE_{UM}$ | = | Project emissions from uncombusted methane during the reporting period (MT $CO_2$e) |
| $i$ | = | Use of methane (oxidation or alternative end-use) by all qualifying and non-qualifying destruction devices |

| | | |
|---|---|---|
| $PE_{NO,i}$ | = | Project emissions of non-oxidized methane emitted as a result of incomplete oxidation of the ventilation air stream during the reporting period; calculated separately for each destruction device (MT $CH_4$) |
| $GWP_{CH4}$ | = | Global warming potential of methane (MT $CO_2e$/MT $CH_4$) |

With:

$$PE_{NO,i} = \sum_{y} (VA_{flow,i,y} \times 60 + CA_{flow,i,y} \times 60) \times C_{CH4,exhaust,i} \times 0.0423 \times 0.000454$$

*Where,*

| | | |
|---|---|---|
| $y$ | = | Hours during which destruction device was operational during reporting period (h) |
| $VA_{flow,i,y}$ | = | Hourly average flow rate of ventilation air sent to a device for destruction through use i during the reporting period (scfm) |
| $CA_{flow,i,y}$ | = | Hourly average flow rate of cooling air sent to a destruction device after the metering point of the ventilation air stream during period y (scfm) |
| 60 | = | Number of minutes in an hour |
| $C_{CH4,exhaust,i}$ | = | Weighted average of measured methane concentration of exhaust gas emitted from the destruction device during the reporting period (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

With:

$$C_{CH4,exhaust,i} = \frac{\sum_y \left[\left(VA_{flow,i,y} \times 60 + CA_{flow,i,y} \times 60\right) \times C_{CH4,exhaust,y}\right]}{\sum_y \left(VA_{flow,i,y} \times 60 + CA_{flow,i,y} \times 60\right)}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,exhaust,y}$ | = | Hourly average methane concentration of exhaust gas (scf $CH_4$/scf) |

Methane concentrations and flow rates must be recorded every two minutes with averages calculated at least hourly. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(l) If gas flow metering equipment provides an actual flow rate instead of a flow rate adjusted to standard conditions, apply equation 5.11 to standardize the flow rate of VA entering the destruction device.

**Equation 5.11: Flow Rate or Volume Adjusted for Temperature and Pressure**

$$VA_{adjusted,y} = VA_{actual,y} \times \frac{519.67}{T_{VAinflow,y}} \times \frac{P_{VAinflow,y}}{1}$$

*Where,*

| | | |
|---|---|---|
| $VA_{adjusted,y}$ | = | Average flow rate or total volume of ventilation air sent to a destruction device during time interval y, adjusted to standard conditions (scfm or scf) |
| $VA_{actual,y}$ | = | Measured average flow rate or total volume of ventilation air sent to a destruction device during time interval y (acfm or acf) |
| $T_{VAinflow,y}$ | = | Measured absolute temperature of ventilation air sent to a destruction device for the time interval y, °R = °F + 459.67 (°R) |
| $P_{VAinflow,y}$ | = | Measured absolute pressure of ventilation air sent to a destruction device for the time interval y (atm) |

### 5.2. Active Underground Mine Methane Drainage Activities

(a) 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 5.12.

(b) If a mine that has historically sent MM to a natural gas pipeline ceases to do so, MM from that source (pre-mining surface wells, pre-mining in-mine boreholes, or post-mining gob wells) is ineligible for emission reduction under this protocol, even if the MM is sent to an otherwise eligible destruction device. If a mine begins to inject MM into a natural gas pipeline while the offset project is ongoing, MM from that source is ineligible for emission reductions going forward.

(c) MM that is injected into a natural gas pipeline in the project scenario is not accounted for in the project emissions or baseline emissions, since it is injected in both scenarios.

**Equation 5.12: 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

(a) 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 4.2 and using equation 5.13.

**Equation 5.13: Baseline Emissions**

$$BE = BE_{MD} + BE_{MR}$$

*Where,*

| | | |
|---|---|---|
| *BE* | = | Baseline emissions during the reporting period (MT $CO_2e$) |
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2e$) |
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere during the reporting period (MT $CO_2e$) |

(b) Baseline emissions from the destruction of MM ($BE_{MD}$) must be quantified using equation 5.14.

(c) $BE_{MD}$ must include the estimated $CO_2$ emissions from the destruction of MM in non-qualifying devices.

(d) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

**Equation 5.14: Baseline Emissions from Destruction of Methane**

$$BE_{MD} = \sum_{i} MD_{B,i} \times CEF_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2e$) |
| *i* | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by non-qualifying destruction devices |
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2e$/MT $CH_4$) |

(e) The amount of mine methane destroyed ($MD_{B,i}$) must be quantified using equation 5.15.

(f) MG can originate from three distinct sources for active underground mine methane drainage activities: pre-mining surface wells, pre-mining in-mine boreholes, and post-mining gob wells. MG from these sources must be measured and accounted for individually per the equations in this section.

(g) For the purpose of baseline quantification, only non-qualifying destruction devices that were operating during the year prior to offset project commencement should be taken into account.

(h) For each eligible methane source, the volume or mass of MG that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be determined by calculating and comparing:

(1) The volume or mass of MG sent to non-qualifying destruction devices during the current reporting period, adjusted for temperature and pressure using equation 5.23, if applicable;

(2) The volume or mass of MG sent to non-qualifying destruction devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using equation 5.23, if applicable, and averaged according to the length of the reporting period; and

(3) The volume or mass of MG sent to non-qualifying destruction devices during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using equation 5.23, if applicable, and averaged according to the length of the reporting period.

(i) For each methane source, the largest of the three quantities determined in sections 5.2.1(h)(1)-(3) must be used for the volume of MG that would have been sent to a non-qualifying device for destruction through use i during the reporting period in the baseline scenario ($PSW_{B,i}$, $PIB_{B,i,}$ and $PGW_{B,i}$) in equations 5.15 and 5.16.

(j) If using a quantity for $PSW_{B,i}$, $PIB_{B,i,}$ or $PGW_{B,i}$ determined by section 5.2.1(h)(1), data for daily volume of mine gas ($DV_t$), methane concentration of mine gas ($C_{CH4,t}$), volume of mine gas sent for destruction with ventilation air ($MG_{SUPP,i}$), and methane concentration of mine gas sent for destruction with ventilation air ($C_{CH4,MG}$) must be monitored for the non-qualifying destruction devices and used in equations 5.15 and 5.16.

(k) If using a quantity for $PSW_{B,i}$, $PIB_{B,i,}$ or $PGW_{B,i}$ determined by section 5.2.1(h)(2) or 5.2.1(h)(3), historical data for daily volume of mine gas ($DV_t$), methane concentration of mine gas ($C_{CH4,t}$), volume of mine gas sent for destruction with ventilation air ($MG_{SUPP,i}$), and methane concentration of mine gas sent for destruction with ventilation air ($C_{CH4,MG}$) must be used in equations 5.15 and 5.16, if available.

(l) If using a quantity for $PSW_{B,i}$, $PIB_{B,i,}$ or $PGW_{B,i}$ determined by section 5.2.1(h)(2) or 5.2.1(h)(3), and historical data for daily volume of mine gas ($DV_t$) is not available, the highest single day volume of mine gas sent to any qualifying or non-qualifying destruction device during the reporting period must be used in place of historical data.

(m) If using a quantity for $PSW_{B,i}$, $PIB_{B,i,}$ or $PGW_{B,i}$ determined by section 5.2.1(h)(2) or 5.2.1(h)(3), and historical data for volume of mine gas sent for destruction with ventilation air ($MG_{SUPP,i}$) is not available, the largest volume of mine gas sent to any qualifying or non-qualifying destruction device during the reporting period must be used in place of historical data.

(n) If using a quantity for $PSW_{B,i}$, $PIB_{B,i,}$ or $PGW_{B,i}$ determined by section 5.2.1(h)(2) or 5.2.1(h)(3), and historical data for methane concentration of mine gas ($C_{CH4,t}$) and methane concentration of mine gas sent for destruction with ventilation air ($C_{CH4,MG}$) are not available, the highest single-hour average methane concentrations during the reporting period must be used in place of historical data.

(o) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.15: Methane Destroyed in Baseline**

$MD_{B,i} = (MM_{B,i} \times DE_i)$

*Where,*

| | | |
|---|---|---|
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period; 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 non-qualifying destruction devices |
| $MM_{B,i}$ | = | Measured methane that would have been sent to non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |

With:

$MM_{B,i} = (PSW_{B,i} \times C_{CH4} + PIB_{B,i} \times C_{CH\,4} + PGW_{B,i} \times C_{CH4}) \times 0.0423 \times 0.000454$

*Where,*

| | | |
|---|---|---|
| $PSW_{B,i}$ | = | Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{B,i}$ | = | Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PGW_{B,i}$ | = | Volume of MG from post-mining gob wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas that would have been sent to non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |

| | | |
|---|---|---|
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

With:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(p) Baseline emissions from the release of methane ($BE_{MR}$) must be quantified using equation 5.16.

(q) $BE_{MR}$ must account for the total amount of methane actually destroyed by all qualifying and non-qualifying devices during the reporting period.

(r) 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 protocol, a well at an active underground mine is considered mined through when any of the following occur:

(1) 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;

(2) 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;

(3) 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

(4) 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.

(s) If using section 5.2.1(r)(1), (2), or (3) 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.

(t) 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 3.5(d)(2) 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.

(u) If an MMC project at an active underground mine consists of both VAM and methane drainage activities, MG extracted from a methane drainage system ($MG_{SUPP,i}$) 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 5.16 as $MG_{SUPP,i.}$

(v) 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 5.16: Baseline Emissions from Release of Methane**

$$BE_{MR} = \sum_i [(PSW_{P,i} \times C_{CH4} - PSW_{B,i,} \times C_{CH4}) + (PIB_{P,i} \times C_{CH4} - PIB_{B,i} \times C_{CH4}) + (PGW_{P,i} \times C_{CH4} - PGW_{B,i} \times C_{CH4}) - MG_{SUPP,i} \times C_{CH4,MG}] \times 0.0423 \times 0.000454 \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere during the reporting period (MT $CO_2$e) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying destruction devices |
| $PSW_{P,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per equation 5.17 in accordance with sections 5.2.1(r), (s), and (t) must be quantified (scf) |
| $PSW_{B,i}$ | = | Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{B,i}$ | = | Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PGW_{P,i}$ | = | Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PGW_{B,i}$ | = | Volume of MG from post-mining gob wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| $MG_{SUPP,i}$ | = | Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period (scf) |
| $C_{CH4,MG}$ | = | Weighted average of measured methane concentration of captured mine gas sent with ventilation air to qualifying and non-qualifying destruction devices during the reporting period (scf $CH_4$/scf) |

| | | |
|---|---|---|
| 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 $CH_4$) |

With:

$PSW_{P,i} = PSWe_i + PSWnqd_i$

*Where,*

| | | |
|---|---|---|
| $PSWe_i$ | = | Volume of MG from pre-mining surface wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period; quantified using equation 5.17 (scf) |
| $PSWnqd_i$ | = | Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period (scf) |

And:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

And:

$$C_{CH4MG} = \frac{\sum_t (DV_{MG,t} \times C_{CH4,MG,t})}{\sum_t DV_{MG,t}}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,MG,t}$ | = | Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf $CH_4$/scf) |
| $DV_{MG,t}$ | = | Daily volume of mine gas sent with ventilation air to destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(w) The eligible amount of MG from pre-mining surface wells destroyed by qualifying devices ($PSWe_i$) must be determined by using equation 5.17.

**Equation 5.17: Eligible MG from Pre-mining Surface Boreholes**

$PSWe_i = PSWe_{pre,i} + PSWe_{post,i}$

*Where,*

| | | |
|---|---|---|
| $PSWe_i$ | = | Volume of MG from pre-mining surface wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period for use in equation 5.16. (scf) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, etc.) by qualifying destruction devices |
| $PSWe_{pre,i}$ | = | Volume of MG sent to qualifying destruction devices, 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 (scf) |
| $PSWe_{post,i}$ | = | Volume of MG sent to qualifying destruction devices in the reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods (scf) |

### 5.2.2. Quantifying Project Emissions

(a) Project emissions must be quantified over a consecutive twelve month period.

(b) 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 4.2 and using equation 5.18.

(c) 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 5.18: Project Emissions**

$PE = PE_{EC} + PE_{MD} + PE_{UM}$

*Where,*

| | | |
|---|---|---|
| $PE$ | = | Project emissions during the reporting period (MT $CO_2$e) |
| $PE_{EC}$ | = | Project emissions from energy consumed to capture and destroy methane during the reporting period (MT $CO_2$e) |

| | | |
|---|---|---|
| $PE_{MD}$ | = | 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 $CO_2e$) |

(d) 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 5.19.

(e) 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 5.19.

**Equation 5.19: Project Emissions from Energy Consumed to Capture and Destroy Methane**

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1000}$$

*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 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 A.1 (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 appendix A (kg $CO_2$/volume) |
| 1/1000 | = | Conversion of kg to metric tons |

(f) Project emissions from the destruction of methane ($PE_{MD}$) must be quantified using equation 5.20.

(g) Project emissions must include the $CO_2$ emissions resulting from the destruction of all MG from pre-mining surface wells that took place during the reporting period regardless of whether or not the well is mined through by the end of the reporting period.

**Equation 5.20: Project Emissions from Destruction of Captured Methane**

$$PE_{MD} = \sum_{i} MD_{P,i} \times CEF_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $PE_{MD}$ | = | Project emissions from destruction of methane during the reporting period (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 and non-qualifying destruction devices |
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2e$/MT $CH_4$) |

(h) The amount of methane destroyed ($MD_i$) must be quantified using equation 5.21.

(i) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.21: Methane Destroyed**

$$MD_{P,i} = (MM_{P,i} \times DE_i)$$

*Where,*

| | | |
|---|---|---|
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period; 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 and non-qualifying destruction devices |

| | | |
|---|---|---|
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |

With:

$MM_{P,i}$ = ($PSW_{P,all,i}$ x $C_{CH4}$ + $PIB_{P,i}$ x $C_{CH4}$ + $PGW_{P,i}$ x $C_{CH4}$ - $MG_{SUPP,i}$ x $C_{CH4,MG}$) x 0.0423 x 0.000454

*Where,*

| | | |
|---|---|---|
| $PSW_{P,all,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PGW_{P,i}$ | = | Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| $MG_{SUPP,i}$ | = | Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period (scf) |
| $C_{CH4,MG}$ | = | Weighted average of measured methane concentration of captured mine gas sent with ventilation air to qualifying and non-qualifying destruction devices during the reporting period (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

And:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_{MG,t}}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

And:

$$C_{CH4MG} = \frac{\sum_t (DV_{MG,t} \times C_{CH4,MG,t})}{\sum_t DV_{MG,t}}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,MG,t}$ | = | Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf $CH_4$/scf) |
| $DV_{MG,t}$ | = | Daily volume of mine gas sent with ventilation air to destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(j) Project emissions from uncombusted methane ($PE_{UM}$) must be quantified using equation 5.22.

(k) Project emissions from uncombusted methane must include emissions from all MG from pre-mining surface wells sent to destruction devices during the reporting period regardless of whether or not the well is mined through by the end of the reporting period.

(l) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.22: Project Emissions from Uncombusted Methane**

$$PE_{UM} = \sum_i [MM_{P,i} \times (1 - DE_i)] \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $PE_{UM}$ | = | Project emissions from uncombusted methane during the reporting period (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 and non-qualifying destruction devices |
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period; calculated separately for each destruction device (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |
| $GWP_{CH4}$ | = | Global warming potential of methane (MT $CO_2e$/MT $CH_4$) |

With:

$$MM_{P,i} = (PSW_{P,all,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + PGW_{P,i} \times C_{CH4} - MG_{SUPP,i} \times C_{CH4,MG}) \times 0.0423 \times 0.000454$$

*Where,*

| | | |
|---|---|---|
| $PSW_{P,all,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PGW_{P,i}$ | = | Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| $MG_{SUPP,i}$ | = | Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period (scf) |
| $C_{CH4,MG}$ | = | Weighted average of measured methane concentration of captured mine gas sent with ventilation air to qualifying and non-qualifying destruction devices during the reporting period (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

And:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

$C_{CH4,t}$ = Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf)

$DV_t$ = Daily volume of mine gas sent to a destruction device (scf)

And:

$$C_{CH4MG} = \frac{\sum_t (DV_{MG,t} \times C_{CH4,MG,t})}{\sum_t DV_{MG,t}}$$

*Where,*

$C_{CH4,MG,t}$ = Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf $CH_4$/scf)

$DV_{MG,t}$ = Daily volume of mine gas sent with ventilation air to destruction device (scf)

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(m) If gas flow metering equipment provides an actual flow rate or volume instead of a flow rate or volume adjusted to standard conditions, use equation 5.23 to standardize the amount of MG sent to each qualifying and non-qualifying device during the reporting period.

**Equation 5.23: MG Flow Rate or Volume Adjusted for Temperature and Pressure**

$$MG_{adjusted,y} = MG_{actual,y} \times \frac{519.67}{T_{MG,y}} \times \frac{P_{MG,y}}{1}$$

*Where,*

$MG_{adjusted,y}$ = Average flow rate or total volume of MG sent to a destruction device during time interval y, adjusted to standard conditions (scfm or scf)

$MG_{actual,y}$ = Measured average flow rate or total volume of MG sent to a destruction device during time interval y (acfm or acf)

| | | |
|---|---|---|
| $T_{MG,y}$ | = | Measured absolute temperature of MG for the time interval y, °R=°F + 459.67 (°R) |
| $P_{MG,y}$ | = | Measured absolute pressure of MG for the time interval y (atm) |

### 5.3. Active Surface Mine Methane Drainage Activities

(a) 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 5.24.

**Equation 5.24: GHG Emission Reductions**

$$ER = BE - PE$$

*Where,*

| | | |
|---|---|---|
| $ER$ | = | Emission reductions achieved by the project during the reporting period (MT $CO_2$e) |
| $BE$ | = | Baseline emissions during the reporting period (MT $CO_2$e) |
| $PE$ | = | Project emissions during the reporting period (MT $CO_2$e) |

#### 5.3.1. Quantifying Baseline Emissions

(a) 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 4.3 and using equation 5.25.

**Equation 5.25: Baseline Emissions**

$$BE = BE_{MD} + BE_{MR}$$

*Where,*

| | | |
|---|---|---|
| $BE$ | = | Baseline emissions during the reporting period (MT $CO_2$e) |
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2$e) |
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere during the reporting period (MT $CO_2$e) |

(b) Baseline emissions from the destruction of SMM ($BE_{MD}$) must be quantified using equation 5.26.

(c) $BE_{MD}$ must include the estimated $CO_2$ emissions from the destruction of SMM in non-qualifying devices.

(d) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

**Equation 5.26: Baseline Emissions from Destruction of Methane**

$$BE_{MD} = \sum_{i} MD_{B,i} \times CEF_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2e$) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by non-qualifying destruction devices |
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2e$/MT $CH_4$) |

(e) The amount of mine methane destroyed ($MD_{B,i}$) must be quantified using equation 5.27.

(f) MG can originate from five distinct sources for active surface mine methane drainage activities: pre-mining surface wells, pre-mining in-mine boreholes, existing CBM wells that would otherwise be shut-in and abandoned as a result of encroaching mining, abandoned wells that are reactivated, and converted dewatering wells. MG from these sources must be measured and accounted for individually per the equations in this section.

(g) For the purpose of baseline quantification, only non-qualifying destruction devices that were operating during the year prior to offset project commencement should be taken into account.

(h) For each eligible methane source, the volume or mass of MG that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be determined by calculating and comparing:

(1) The volume or mass of MG sent to non-qualifying destruction devices during the current reporting period, adjusted for temperature and pressure using equation 5.38, if applicable;

(2) The volume or mass of MG sent to non-qualifying destruction devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using equation 5.38, if

applicable, and averaged according to the length of the reporting period; and

(3) The volume or mass of MG sent to non-qualifying destruction devices during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using equation 5.38, if applicable, and averaged according to the length of the reporting period.

(i) For each methane source, the largest of the three quantities determined in sections 5.3.1(h)(1)-(3) must be used for the volume of MG that would have been sent to a non-qualifying device for destruction through use i during the reporting period in the baseline scenario ($PSW_{B,i}$, $PIB_{B,i}$, $ECW_{B,i}$, $AWR_{B,i,}$ and $CDW_{B,i}$) in equations 5.27 and 5.28.

(j) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $ECW_{B,i}$, $AWR_{B,i,}$ and $CDW_{B,i}$ determined by section 5.3.1(h)(1), data for daily volume of mine gas ($DV_t$) and methane concentration of mine gas ($C_{CH4,t}$) must be monitored for the non-qualifying destruction devices and used in equations 5.27 and 5.28.

(k) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $ECW_{B,i}$, $AWR_{B,i,}$ and $CDW_{B,i}$ determined by section 5.3.1(h)(2) or 5.3.1(h)(3), historical data for daily volume of mine gas ($DV_t$), and methane concentration of mine gas ($C_{CH4,t}$) must be used in equations 5.27 and 5.28, if available.

(l) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $ECW_{B,i}$, $AWR_{B,i,}$ and $CDW_{B,i}$ determined by section 5.3.1(h)(2) or 5.3.1(h)(3), and historical data for daily volume of mine gas ($DV_t$) is not available, the highest single day volume of mine gas sent to any qualifying or non-qualifying destruction device during the reporting period must be used in place of historical data.

(m) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $ECW_{B,i}$, $AWR_{B,i,}$ and $CDW_{B,i}$ determined by section 5.3.1(h)(2) or 5.3.1(h)(3), and historical data for methane concentration of mine gas ($C_{CH4,t}$) is not available, the highest single-hour average methane concentration during the reporting period must be used in place of historical data.

(n) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.27: Methane Destroyed in Baseline**

$MD_{B,i} = (MM_{B,i} \times DE_i)$

*Where,*

| | | |
|---|---|---|
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period; 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 non-qualifying destruction devices |
| $MM_{B,i}$ | = | Measured methane that would have been sent to non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |

With:

$MM_{B,i} = (PSW_{B,i} \times C_{CH4} + PIB_{B,i} \times C_{CH\,4} + ECW_{B,i} \times C_{CH4} + AWR_{B,i} \times C_{CH4} + \mathrm{CDW}_{B,i} \times C_{CH4}) \times 0.0423 \times 0.000454$

*Where,*

| | | |
|---|---|---|
| $PSW_{B,i}$ | = | Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{B,i}$ | = | Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $ECW_{B,i}$ | = | Volume of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |

| | | |
|---|---|---|
| $AWR_{B,i}$ | = | Volume of MG from abandoned wells that are reactivated that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $CDW_{B,i}$ | = | Volume of MG from converted dewatering wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas that would have been sent to non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

With:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(o) Baseline emissions from the release of methane ($BE_{MR}$) must be quantified using equation 5.28.

(p) $BE_{MR}$ must account for the total amount of methane actually destroyed by all qualifying and non-qualifying devices during the reporting period.

(q) 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 mined through). With the exception of pre-mining in-mine boreholes, all other methane sources must demonstrate that the well is mined through. For the purposes of this protocol, a well at an active surface mine is considered mined through when either of the following occurs:

(1) The well is physically bisected by surface mining activities, such as excavation of overburden, drilling and blasting, and removal of the coal; or

(2) 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.

(r) If using section 5.3.1(g)(1) 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.

(s) 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 5.28: Baseline Emissions from Release of Methane**

$$BE_{MR} = \sum_{i} [(PSW_{P,i} \times C_{CH4} - PSW_{B,i} \times C_{CH4}) + (PIB_{P,i} \times C_{CH4} - PIB_{B,i} \times C_{CH4}) + (ECW_{P,i} \times C_{CH4} - ECW_{B,i} \times C_{CH4}) + (AWR_{P,i} \times C_{CH4} - AWR_{B,i} \times C_{CH4}) + (CDW_{P,i} \times C_{CH4} - CDW_{B,i} \times C_{CH4})] \times 0.0423 \times 0.000454 \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere during the reporting period (MT $CO_2$e) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying destruction devices |
| $PSW_{P,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per equation 5.29 in accordance with sections 5.3.1(q) and (r) must be quantified (scf) |

| | | |
|---|---|---|
| $PSW_{B,i}$ | = | Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{B,i}$ | = | Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $ECW_{P,i}$ | = | Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per equation 5.30 in accordance with sections 5.3.1(q) and (r) must be quantified (scf) |
| $ECW_{B,i}$ | = | Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $AWR_{P,i}$ | = | Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per equation 5.31 in accordance with sections 5.3.1(q) and (r) must be quantified (scf) |
| $AWR_{B,i}$ | = | Volume of MG from abandoned wells that are reactivated that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $CDW_{P,i}$ | = | Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per equation 5.32 in accordance with sections 5.3.1(q) and (r) must be quantified (scf) |
| $CDW_{B,i}$ | = | Volume of MG from converted dewatering wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| 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 $CH_4$)

With:

$PSW_{P,i} = PSWe_i + PSWnqd_i$

*Where,*

$PSWe_i$ = Volume of MG from pre-mining surface wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period; quantified using equation 5.29 (scf)

$PSWnqd_i$ = Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And:

$ECW_{P,i} = ECWe_i + ECWnqd_i$

*Where,*

$ECWe_i$ = Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period; quantified using equation 5.30 (scf)

$ECWnqd_i$ = Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And:

$AWR_{P,i} = AWRe_i + AWRnqd_i$

*Where,*

$AWRe_i$ = Volume of MG from abandoned wells that are reactivated sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period; quantified using equation 5.31 (scf)

$AWRnqd_i$ = Volume of MG from abandoned wells that are reactivated sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And:

$CDW_{P,i} = CDWe_i + CDWnqd_i$

*Where,*

| | | |
|---|---|---|
| $CDWe_i$ | = | Volume of MG from converted dewatering wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period; quantified using equation 5.32 (scf) |
| $CDWnqd_i$ | = | Volume of MG from converted dewatering wells sent to non-qualifying devices for destruction through use i during the reporting period (scf) |

And:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(t) The eligible amount of MG destroyed by qualifying devices must be determined by using equations 5.29, 5.30, 5.31, and 5.32.

**Equation 5.29: Eligible MG from Pre-mining Surface Wells**

$PSWe_i = PSWe_{pre,i} + PSWe_{post,i}$

*Where,*

| | | |
|---|---|---|
| $PSWe_i$ | = | Volume of MG from pre-mining surface wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period for use in equation 5.28 (scf) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction devices |
| $PSWe_{pre,i}$ | = | Volume of MG sent to qualifying destruction devices, 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 (scf) |

| | | |
|---|---|---|
| $PSWe_{post,i}$ | = | Volume of MG sent to qualifying destruction devices in the reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods (scf) |

**Equation 5.30: Eligible MG from Existing Coal Bed Methane Wells that Would Otherwise Be Shut-in and Abandoned as a Result of Encroaching Mining**

$$ECWe_i = ECWe_{pre,i} + ECWe_{post,i}$$

*Where,*

| | | |
|---|---|---|
| $ECWe_i$ | = | Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period for use in equation 5.28 (scf) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction devices |
| $ECWe_{pre,i}$ | = | Volume of MG sent to qualifying destruction devices, from the beginning of the crediting period through the end of the reporting period, captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during the reporting period (scf) |
| $ECWe_{post,i}$ | = | Volume of MG sent to qualifying destruction devices in the reporting period captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during earlier reporting periods (scf) |

**Equation 5.31: Eligible MG from Abandoned Wells that are Reactivated**

$$AWRe_i = AWRe_{pre,i} + AWRe_{post,i}$$

*Where,*

| | | |
|---|---|---|
| $AWRe_i$ | = | Volume of MG from abandoned wells that are reactivated sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period for use in equation 5.28 (scf) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction devices |
| $AWRe_{pre,i}$ | = | Volume of MG sent to qualifying destruction devices, 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 (scf) |

| | | |
|---|---|---|
| $AWRe_{post,i}$ | = | Volume of MG sent to qualifying destruction devices in the reporting period captured from abandoned wells that are reactivated that were mined through during earlier reporting periods (scf) |

**Equation 5.32: Eligible MG from Converted Dewatering Wells that are Reactivated**

$CDWe_i = CDWe_{pre,i} + CDWe_{post,i}$

*Where,*

| | | |
|---|---|---|
| $CDWe_i$ | = | Volume of MG from converted dewatering wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period for use in equation 5.28 (scf) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by qualifying destruction devices |
| $CDWe_{pre,i}$ | = | Volume of MG sent to qualifying destruction devices, 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 (scf) |
| $CDWe_{post,i}$ | = | Volume of MG sent to qualifying destruction devices in the reporting period captured from converted dewatering wells that were mined through during earlier reporting periods (scf) |

### 5.3.2 Quantifying Project Emissions

(a) Project emissions must be quantified over a consecutive twelve month period.

(b) 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 4.3 and using equation 5.33.

(c) 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 5.33: Project Emissions**

$PE = PE_{EC} + PE_{MD} + PE_{UM}$

*Where,*

| | | |
|---|---|---|
| $PE$ | = | Project emissions during the reporting period (MT $CO_2$e) |
| $PE_{EC}$ | = | Project emissions from energy consumed to capture and destroy methane during the reporting period (MT $CO_2$e) |
| $PE_{MD}$ | = | Project emissions from destruction of methane during the reporting period (MT $CO_2$e) |

| | | |
|---|---|---|
| $PE_{UM}$ | = | Project emissions from uncombusted methane during the reporting period (MT $CO_2$e) |

(d) 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 5.34.

(e) 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 5.34.

**Equation 5.34: Project Emissions from Energy Consumed to Capture and Destroy Methane**

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1000}$$

*Where,*

| | | |
|---|---|---|
| $PE_{EC}$ | = | Project emissions from energy consumed to capture and destroy methane during the reporting period (MT $CO_2$e) |
| $CONS_{ELEC}$ | = | 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 appendix A (MT $CO_2$e/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 A.1 (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 appendix A (kg $CO_2$/volume) |
| 1/1000 | = | Conversion of kg to metric tons |

(f) Project emissions from the destruction of methane ($PE_{MD}$) must be quantified using equation 5.35.

(g) Project emissions must include the $CO_2$ emissions resulting from the destruction of all MG that took place during the reporting period regardless of whether or not the well is mined through by the end of the reporting period.

**Equation 5.35: Project Emissions from Destruction of SMM**

$$PE_{MD} = \sum_{i} MD_{P,i} \times CEF_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $PE_{MD}$ | = | Project emissions from destruction of methane during the reporting period (MT $CO_2$e) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying destruction devices |
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2$e/MT $CH_4$) |

(h) The amount of mine methane destroyed ($MD_i$ ) must be quantified using equation 5.36.

(i) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.36: Methane Destroyed**

$$MD_{P,i} = (MM_{P,i} \times DE_i)$$

*Where,*

| | | |
|---|---|---|
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period; 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 and non-qualifying destruction devices |
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |

With:

$MM_{P,i}$ = $(PSW_{P,all,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + ECW_{P,all,i} \times C_{CH4} + AWR_{P,all,i} \times C_{CH4} \times CDW_{P,all,i,} \times C_{CH4}) \times 0.0423 \times 0.000454$

*Where,*

| | | |
|---|---|---|
| $PSW_{P,all,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $ECW_{P,all,i}$ | = | Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $AWR_{P,all,i}$ | = | Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $CDW_{P,all,i}$ | = | Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

With:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(j) Project emissions from uncombusted methane ($PE_{UM}$) must be quantified using equation 5.37.

(k) Project emission from uncombusted methane must include emissions from all MG sent to destruction devices during the reporting period regardless of whether or not the well is mined through by the end of the reporting period.

(l) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.37: Project Emissions from Uncombusted Methane**

$$PE_{UM} = \sum_{i} [MM_{P,i} \times (1 - DE_i)] \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $PE_{UM}$ | = | Project emissions from uncombusted methane during the reporting period (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 and non-qualifying destruction devices |
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period; calculated separately for each destruction device (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |
| $GWP_{CH4}$ | = | Global warming potential of methane (MT $CO_2e$/MT $CH_4$) |

With:

$MM_{P,i}$ = ($PSW_{P,all,i}$ x $C_{CH4}$ + $PIB_{P,i}$ x $C_{CH4}$ + $ECW_{P,all,i}$ x $C_{CH4}$ + $AWR_{P,all,i}$ x $C_{CH4}$ x $CDW_{P,all,i,}$ x $C_{CH4}$) x 0.0423 x 0.000454

*Where,*

| | | |
|---|---|---|
| $PSW_{P,all,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $ECW_{P,all,i}$ | = | Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $AWR_{P,all,i}$ | = | Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $CDW_{P,all,i}$ | = | Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

With:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(m) If gas flow metering equipment provides an actual flow rate or volume instead of a flow rate or volume adjusted to standard conditions, use equation 5.38 to standardize the amount of MG sent to each qualifying and non-qualifying device during the reporting period.

**Equation 5.38: MG Flow Rate or Volume Adjusted for Temperature and Pressure**

$$MG_{adjusted,y} = MG_{actual,y} \times \frac{519.67}{T_{MG,y}} \times \frac{P_{MG,y}}{1}$$

*Where,*

| | | |
|---|---|---|
| $MG_{adjusted,y}$ | = | Average flow rate or total volume of MG sent to a destruction device during time interval y, adjusted to standard conditions (scfm) |
| $MG_{actual,y}$ | = | Measured average flow rate or total volume of MG sent to a destruction device during time interval y (acfm) |
| $T_{MG,y}$ | = | Measured absolute temperature of MG for the time interval y, °R=°F + 459.67 (°R) |
| $P_{MG,y}$ | = | Measured absolute pressure of MG for the time interval y (atm) |

### 5.4. Abandoned Underground Mine Methane Recovery Activities

(a) 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) and applying an uncertainty deduction (UD) using equation 5.39.

(b) Abandoned underground mine methane recovery activities that meet the following conditions are not subject to an uncertainty deduction and should calculate GHG emission reductions for a reporting period (ER) using an uncertainty deduction (UD) equal to 1:

 (1) The project uses hyperbolic emission rate decline curve coefficients derived from mine-specific data measured from pre-existing wells or boreholes open to the atmosphere according to the provisions of section 5.4.1(u); or

(2) The project extracts methane exclusively from mines that utilized methane drainage systems when active.

(c) If an abandoned underground mine injected MM into a natural gas pipeline while active, MM from that source (pre-mining surface wells drilled into the mine during active mining operations, pre-mining in-mine boreholes drilled into the mine during active mining operations, post-mining gob wells drilled into the mine during active mining operations) is ineligible for emission reductions under this protocol, even if the MM is sent to an otherwise eligible destruction device.

(d) Abandoned underground mines that injected MM into a natural gas pipeline while active must not capture and destroy mine methane from newly drilled wells as it is assumed that methane from this source would have otherwise been injected into a pipeline.

**Equation 5.39: GHG Emission Reductions**

$$ER = (BE - PE) \times UD$$

*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 $CO_2e$) |
| *UD* | = | Uncertainty deduction; UD = 0.8 if using default hyperbolic emission rate decline curve coefficients and the mine did not utilize a methane drainage system when active, UD = 1 if using default hyperbolic emission rate decline curve coefficients and the abandoned mine utilized a methane drainage system when active, UD = 1 if using hyperbolic emission rate decline curve coefficients derived from measured data from pre-existing wells or boreholes open to the atmosphere |

### 5.4.1 Quantifying Baseline Emissions

(a) 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 4.4 and using equation 5.40.

(b) The emission reductions in any given reporting period must be equal to or less than the baseline emissions for that reporting period.

**Equation 5.40: Baseline Emissions**

$$BE = BE_{MD} + BE_{MR}$$

*Where,*

| | | |
|---|---|---|
| $BE$ | = | Baseline emissions during the reporting period (MT $CO_2e$) |
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2e$) |
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere during the reporting period (MT $CO_2e$) |

(c) Baseline emissions from the destruction of AMM ($BE_{MD}$) must be quantified using equation 5.41.

(d) $BE_{MD}$ must include the estimated $CO_2$ emissions from the destruction of AMM in non-qualifying devices.

(e) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

**Equation 5.41: Baseline Emissions from Destruction of Methane**

$$BE_{MD} = \sum_i MD_{B,i} \times CEF_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $BE_{MD}$ | = | Baseline emissions from destruction of methane during the reporting period (MT $CO_2e$) |
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by non-qualifying destruction devices |
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2e$/MT $CH_4$) |

(f) The amount of methane that would have been destroyed by non-qualifying devices ($MD_{B,i}$) must be quantified using equation 5.42.

(g) MG can originate from four distinct sources for abandoned underground mine methane recovery activities: pre-mining surface wells drilled into the mine during active mining operations, pre-mining in-mine boreholes drilled into the mine during active mining operations, post-mining gob wells drilled into the mine during active mining operations, and newly drilled surface wells. MG from these sources must be measured and accounted for individually per the equations in this section.

(h) For the purpose of baseline quantification, only non-qualifying destruction devices that were operating during the year prior to offset project commencement should be taken into account.

(i) For each eligible methane source, the volume or mass of MG that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be determined by calculating and comparing:

  (1) The volume or mass of MG sent to non-qualifying destruction devices during the current reporting period, adjusted for temperature and pressure using equation 5.50, if applicable;

  (2) The volume or mass of MG sent to non-qualifying destruction devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using equation 5.50, if applicable and averaged according to the length of the reporting period; and

  (3) The volume or mass of MG sent to non-qualifying destruction devices during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using equation 5.50, if applicable, and averaged according to the length of the reporting period.

(j) For each methane source, the largest of the three quantities determined in sections 5.4.1(i)(1)-(3) must be used for volume of MG that would have been sent to a non-qualifying device for destruction through use i during the reporting period in the baseline scenario ($PSW_{B,i}$, $PIB_{B,i}$, $PGW_{B,i}$, and $NSW_{B,i}$) in equation 5.42

(k) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $PGW_{B,i}$, and $NSW_{B,i}$ determined by section 5.4.1(i)(1), data for daily volume of mine gas ($DV_t$) and methane concentration of mine gas ($C_{CH4,t}$) must be monitored for the non-qualifying destruction devices and used in equation 5.42.

(l) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $PGW_{B,i}$, and $NSW_{B,i}$ determined by section 5.4.1(i)(2) or 5.4.1(i)(3), historical data for daily volume of mine gas ($DV_t$), and methane concentration of mine gas ($C_{CH4,t}$) must be used in equation 5.2, if available.

(m) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $PGW_{B,i}$, and $NSW_{B,i}$ determined by section 5.4.1(i)(2) or 5.4.1(i)(3), and historical data for daily volume of mine gas ($DV_t$) is not available, the highest single day volume of mine gas sent to any qualifying or non-qualifying destruction device during the reporting period must be used in place of historical data.

(n) If using a quantity for $PSW_{B,i}$, $PIB_{B,i}$, $PGW_{B,i}$, and $NSW_{B,i}$ determined by section 5.4.1(i)(2) or 5.4.1(i)(3), and historical data for methane concentration of mine gas ($C_{CH4,t}$) is not available, the highest single-hour average methane concentration during the reporting period must be used in place of historical data.

(o) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.42: Methane Destroyed in Baseline**

$$MD_{B,i} = (MM_{B,i} \times DE_i)$$

*Where,*

| | | |
|---|---|---|
| $MD_{B,i}$ | = | Methane that would have been destroyed through use i by non-qualifying devices during the reporting period; 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 non-qualifying destruction devices |
| $MM_{B,i}$ | = | Measured methane that would have been sent to non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |

$DE_i$ = Efficiency of methane destruction device i, either site-specific or from appendix B (%)

With:

$MM_{B,i}$ = ($PSW_{B,i}$ x $C_{CH4}$ + $PIB_{B,i}$ x $C_{CH\ 4}$ + $PGW_{B,i}$ x $C_{CH4}$ x $NSW_{B,i}$ x $C_{CH4}$ ) x 0.0423 x 0.000454

*Where,*

$PSW_{B,i}$ = Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf)

$PIB_{B,i}$ = Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf)

$PGW_{B,i}$ = Volume of MG from post-mining gob wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf)

$NSW_{B,i}$ = Volume of MG from newly drilled surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period (scf)

$C_{CH4}$ = Weighted average of measured methane concentration of mine gas that would have been sent to non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf)

0.0423 = Standard density of methane (lb $CH_4$/scf $CH_4$)

0.000454 = MT $CH_4$/lb $CH_4$

With:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

$C_{CH4,t}$ = Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf)

$DV_t$ = Daily volume of mine gas sent to a destruction device (scf)

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(p) Baseline emissions from the release of methane ($BE_{MR}$) must be quantified using equation 5.43. Calculations include the application of a hyperbolic emissions rate decline curve. The function is directly related the gassiness of the mine, which is reflective of physical parameters of the coal mine such as the mine size, gas content of the coal, permeability of the coal to the flow of gas.

(q) The decline curve estimates the emission rate of an abandoned mine over time by taking into account the time elapsed since mine closure, the average methane emission rate calculated using available data collected by MSHA over the life of the mine, and whether the mine is sealed or venting. The decline curve for a given mine is initialized at the date of abandonment and extrapolated through the crediting period.

(r) The amount of AMM released in the baseline scenarios (MT $CH_4$) must be determined by calculating and comparing:

(1) The emissions of methane for that reporting period calculated by the decline curve using equation 5.44; and

(2) The total amount of measured methane sent to all qualifying and non-qualifying devices during the reporting period ($MM_{P,i}$) calculated using equation 5.48.

(s) 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 5.43: Baseline Emissions from Release of Methane**

$$BE_{MR} = \left[\min\left(AMM_{DC}, \sum_i MM_{P,i}\right) - \sum_i MM_{B,i}\right] \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $BE_{MR}$ | = | Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (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 and non-qualifying destruction devices |

| | | |
|---|---|---|
| $AMM_{DC}$ | = | Emissions of methane during the reporting period as calculated by the decline curve (MT $CH_4$) |
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $MM_{B,i}$ | = | Measured methane that would have been sent to non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $GWP_{CH4}$ | = | Global warming potential of methane (MT $CO_2e$/MT $CH_4$) |

**Equation 5.44: Methane Emissions Derived from the Hyperbolic Emission Rate Decline Curve**

$$AMM_{DC} = ER_{AMM} \times S \times (1 + b \times D_i \times t)^{\left(\frac{-1}{b}\right)} \times RP_{days} \times 42.3 \times 0.000454$$

*Where,*

| | | |
|---|---|---|
| $AMM_{DC}$ | = | Emissions of methane during the reporting period (MT $CH_4$) |
| $ER_{AMM}$ | = | Average ventilation air methane emission rate over the life of the mine (Mscf/d) |
| $S$ | = | Default effective degree of sealing; S = 1 for venting mines and 0.5 for sealed mines |
| $b$ | = | Dimensionless hyperbolic exponent |
| $D_i$ | = | Initial decline rate (1/day) |
| $t$ | = | Time elapsed from the date of mine closure to midpoint of the reporting period (days) |
| $RP_{days}$ | = | Days in reporting period |
| 42.3 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

(t) The decline curve relies upon hyperbolic emission rate decline curve coefficients. Offset Project Operators or Authorized Project Designees may elect to:

(1) Use the default hyperbolic emission rate decline curve coefficients presented in table 5.1 based upon whether the mine is venting or sealed; or

(2) Use hyperbolic emission rate decline curve coefficients derived from measured data from pre-existing wells or boreholes open to the atmosphere that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default hyperbolic emission

rate decline curve coefficients upon written approval by the Executive Officer. If natural gas seeps are present, an Offset Project Operator or Authorized Project Designee may also include measured data from those emissions.

**Table 5.1: Default Hyperbolic Decline Curve Coefficients**

| Variable | Venting | Sealed |
|---|---|---|
| *b* | 1.886581 | 2.016746 |
| $D_i$ (1/day) | 0.003519 | 0.000835 |

(u) To derive hyperbolic emission rate decline curve coefficients using measured data from pre-existing wells or boreholes open to the atmosphere and natural gas seeps, an Offset Project Operator or Authorized Project Designee must do the following:

(1) Obtain average methane emission rate calculated using available data collected by MSHA over the life of the mine.

(2) After mine closure, three parameters must be monitored:

(A) MG flow rates;

(B) local barometric pressure; and

(C) methane concentration of MG.

(3) Measurements must be of natural flow only with no assist from vacuum pumps or compressors.

(4) If gas flow metering equipment provides an actual or flow rate instead of a flow rate adjusted to standard conditions, apply equation 5.50 to standardize the flow rate of MG venting from pre-existing wells or boreholes open to the atmosphere and natural gas seeps.

(5) The monitored data must be used to develop a correlation between barometric pressure and methane flow rate. Annual average barometric pressure at the site must then be used to normalize the annual methane flow rate.

(6) This normalized flow rate must then be plotted against the time since mine closure in order to derive the hyperbolic emission rate decline curve by fitting the data to a curve in the form of equation 5.44.

### 5.4.2. Quantifying Project Emissions

(a) Project emissions must be quantified over a consecutive twelve month period.

(b) 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 4.4 and using equation 5.45.

(c) 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 5.45: Project Emissions**

$$PE = PE_{EC} + PE_{MD} + PE_{UM}$$

*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 $CO_2e$) |

(d) 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 5.46.

(e) 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 5.46.

**Equation 5.46: Project Emissions from Energy Consumed to Capture and Destroy Methane**

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1000}$$

| | | |
|---|---|---|
| *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 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 A.1 (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 appendix A (kg $CO_2$/volume) |
| 1/1000 | = | Conversion of kg to metric tons |

(f) Project emissions from the destruction of methane ($PE_{MD}$) must be quantified using equation 5.47.

**Equation 5.47: Project Emissions from Destruction of Captured Methane**

$$PE_{MD} = \sum_i MD_{P,i} \times CEF_{CH4}$$

| | | |
|---|---|---|
| *Where,* | | |
| $PE_{MD}$ | = | Project emissions from destruction of methane during the reporting period (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 and non-qualifying destruction devices |
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period (MT $CH_4$) |
| $CEF_{CH4}$ | = | $CO_2$ emission factor for combusted methane (2.744 MT $CO_2e$/MT $CH_4$) |

(g) The amount of methane destroyed ($MD_{P,i}$) must be quantified using equation 5.48.

(h) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.48: Methane Destroyed**

$MD_{P,i} = (MM_{P,i} \times DE_i)$

*Where,*

| | | |
|---|---|---|
| $MD_{P,i}$ | = | Methane destroyed through use i by qualifying and non-qualifying devices during the reporting period; 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 and non-qualifying destruction devices |
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |

With:

$MM_{P,i} = (PSW_{P,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + PGW_{P,i} \times C_{CH4} + NSW_{P,i} \times C_{CH4}) \times 0.0423 \times 0.000454$

*Where,*

| | | |
|---|---|---|
| $PSW_{P,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PGW_{P,i}$ | = | Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $NSW_{P,i}$ | = | Volume of MG from newly drilled surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |

| | | |
|---|---|---|
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

With:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(i) Project emissions from uncombusted methane ($PE_{UM}$) must be quantified using equation 5.49.

(j) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies ($DE_i$) provided in appendix B or site-specific methane destruction efficiencies. Destruction technologies not listed in appendix B must use site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

**Equation 5.49: Uncombusted Methane Emissions**

$$PE_{UM} = \sum_i [MM_{P,i} \times (1 - DE_i)] \times GWP_{CH4}$$

*Where,*

| | | |
|---|---|---|
| $PE_{UM}$ | = | Project emissions from uncombusted methane during the reporting period (MT $CO_2$e) |

| | | |
|---|---|---|
| $i$ | = | Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline etc.) by all qualifying and non-qualifying destruction devices |
| $MM_{P,i}$ | = | Measured methane sent to qualifying and non-qualifying devices for destruction through use i during the reporting period; calculated separately for each destruction device (MT $CH_4$) |
| $DE_i$ | = | Efficiency of methane destruction device i, either site-specific or from appendix B (%) |
| $GWP_{CH4}$ | = | Global warming potential of methane (MT $CO_2$e/MT $CH_4$) |

With:

$MM_{P,i} = (PSW_{P,i} \text{ x } C_{CH4} + PIB_{P,i} \text{ x } C_{CH4} + PGW_{P,i} \text{ x } C_{CH4} + NSW_{P,i} \text{ x } C_{CH4}) \text{ x } 0.0423 \text{ x } 0.000454$

*Where,*

| | | |
|---|---|---|
| $PSW_{P,i}$ | = | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PIB_{P,i}$ | = | Volume of MG from pre-mining in-mine boreholes sent to by qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $PGW_{P,i}$ | = | Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $NSW_{P,i}$ | = | Volume of MG from newly drilled surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf) |
| $C_{CH4}$ | = | Weighted average of measured methane concentration of mine gas sent to qualifying and non-qualifying destruction devices during the reporting period; calculated separately for each methane source (scf $CH_4$/scf) |
| 0.0423 | = | Standard density of methane (lb $CH_4$/scf $CH_4$) |
| 0.000454 | = | MT $CH_4$/lb $CH_4$ |

With:

$$C_{CH4} = \frac{\sum_t (DV_t \times C_{CH4,t})}{\sum_t DV_t}$$

*Where,*

| | | |
|---|---|---|
| $C_{CH4,t}$ | = | Daily average methane concentration of mine gas sent to a destruction device (scf $CH_4$/scf) |

| | | |
|---|---|---|
| $DV_t$ | = | Daily volume of mine gas sent to a destruction device (scf) |

Methane concentrations and flow rates must be recorded every fifteen minutes with averages calculated at least daily. If the Offset Project Operator or Authorized Project Designee monitors and records data at a higher frequency, this data may be used within appropriate variables of the above equations to reflect the higher frequency of data collection.

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.

(k) If gas flow metering equipment provides an actual or flow rate or volume instead of a flow rate or volume adjusted to standard conditions, use equation 5.50 to standardize the amount of MG sent to each qualifying and non-qualifying device during the reporting period and MG flow rates, if deriving hyberbolic emission rate decline curve coefficients from measured data.

**Equation 5.50: MG Flow Rate or Volume Adjusted for Temperature and Pressure**

$$MG_{adjusted,y} = MG_{actual,y} \times \frac{519.67}{T_{MG,y}} \times \frac{P_{MG,y}}{1}$$

*Where,*

| | | |
|---|---|---|
| $MG_{adjusted,y}$ | = | Average flow rate or total volume of MG sent to a destruction device during time interval y, adjusted to standard conditions (scfm or scf) |
| $MG_{actual,y}$ | = | Measured average flow rate or total volume of MG sent to a destruction device during time interval y (acfm or acf) |
| $T_{MG,y}$ | = | Measured absolute temperature of MG for the time interval y, °R=°F + 459.67 (°R) |
| $P_{MG,y}$ | = | Measured absolute pressure of MG for the time interval y (atm) |

## Chapter 6. Monitoring – Quantification Methodology

### 6.1. General Monitoring Requirements

(a) The Offset Project Operator or Authorized Project Designee 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.

(b) Operational activity of the methane drainage and ventilation systems and the destruction devices must be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for during periods in which the destruction device is not operational.

(1) For flares, operation is defined as thermocouple readings above 500°F.

(2) For all other destruction devices, the Offset Project Operator or Authorized Project Designee must demonstrate the destruction device was operational. This demonstration is subject to the review and verification of an ARB-approved third party offset project verification body.

(c) 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.

(d) 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 offset project commencement and when the Offset Project Operator or Authorized Project Designee 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.

(e) Data substitution is allowed for limited circumstances where a project encounters flow rate or methane concentration data gaps. _Offset Project Operators or Authorized Project Designees may apply the data substitution methodology provided in appendix C. 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 measure data to derive hyperbolic emission rate decline curve coefficients and 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:

(a) All instruments must be:

  (1) Inspected and maintained on a quarterly basis, with the activities performed and "as found/as left condition" of the equipment documented;

  (2) Checked per manufacturer specifications by a trained professional for calibration accuracy with the percent drift documented, with the check occurring no more than two months before and one day after the end date of the reporting period; and

  (3) 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.

(b) A check must be performed before any corrective action (e.g., instrument calibration or repositioning) is applied.

(c) If a portable instrument is used (such as a pitot tube or handheld methane analyzer), the portable instrument must be calibrated according to manufacturer's specifications prior to each use.

(d) 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.

(e) 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.

(f) If the check on a piece of equipment reveals accuracy beyond a +/- 5% threshold (reading relative to the reference value), corrective action such as calibration by the manufacturer or a certified service provider is required for that piece of equipment.

(g) 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.

(1) For each check that indicates the piece of equipment was beyond the +/-5% accuracy threshold, the project developer shall calculate total emission reductions using:

(A) The monitored values without correction; and

(B) The monitored values adjusted based on the calibration drift recorded at the time of the check.

(2) The lower of the two emission reduction estimates shall be reported as the scaled emission reduction estimate.

### 6.3. Document Retention

(a) The Offset Project Operator or Authorized Project Designee is required to keep all documentation and information outlined in the Regulation and this protocol. Record retention requirements are set forth in section 95976 of the Regulation.

(b) Information that must be retained by the Offset Project Operator or Authorized Project Designee must include:

(1) All data inputs for the calculation of the project baseline emissions and project emission reductions;

(2) Emission reduction calculations;

(3) NOVs, and any administrative or legal consent orders related to project activities dating back at least three years prior to offset project commencement and for each year of project operation;

(4) Gas flow meter information (model number, serial number, manufacturer's calibration procedures);

(5) Methane analyzer information (model number, serial number, calibration procedures);

(6) Cleaning and inspection records for all gas meters;

(7) Field check results for all gas meters and methane analyzers;

(8) Calibration results for all gas meters and methane analyzers;

(9) Corrective measures taken if meter does not meet performance specifications;

(10) Gas flow data (for each flow meter);

(11) Methane concentration monitoring data;

(12) Gas temperature and pressure readings (only if flow meter does not adjust for temperature and pressure automatically);

(13) Destruction device information (model numbers, serial numbers, installation date, operation dates);

(14) Destruction device monitoring data (for each destruction device);

(15) All maintenance records relevant to the methane collection and/or destruction device(s) and monitoring equipment;

(16) If using a calibrated portable gas analyzer for $CH_4$ content measurement the following records must be retained:

(A) Date, time, and location of methane measurement;

(B) Methane content of gas (% by volume or mass) for each measurement;

(C) Methane measurement instrument information (model number and serial number);

(D) Date, time, and results of instrument calibration; and

(E) Corrective measures taken if instrument does not meet performance specifications.

### 6.4. Active Underground Mine Ventilation Air Methane Activities

(a) The flow rate of ventilation air entering the destruction device must be measured continuously, recorded every two minutes, and adjusted for temperature and pressure, if applicable, to calculate average flow per hour.

(b) 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 recorded every two minutes to calculate average methane concentrations per hour.

(c) 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 least every hour to calculate hourly pressure and temperature.

(d) Offset Project Operators or Authorized Project Designees must monitor the parameters prescribed in table 6.1. 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 6.1. Active Underground Mine VAM Activity Monitoring Parameters**

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) | Comment |
|---|---|---|---|---|---|---|
| 5.4<br>5.5 | $VA_{B,i}$ | Volume of ventilation air that would have been sent to a non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.1.1(g) |
| 5.4<br>5.5<br>5.9 | $C_{CH4,t}$ | Hourly average methane concentration of ventilation air sent to a destruction device | scf $CH_4$/scf | Continuously | m, c | Readings taken every two minutes to calculate average methane concentration per hour |
| 5.4<br>5.5<br>5.9 | $VA_{flow,t}$ | Hourly average flow rate of ventilation air sent to a destruction device | scfm | Continuously | m, c | Readings taken every two minutes to calculate average flow rate per hour; adjusted to standard conditions, if applicable, using equation 5.11 |
| 5.4<br>5.9<br>5.10 | y | Hours during which the destruction | h | Continuously | m | |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) | Comment |
|---|---|---|---|---|---|---|
| | | device was operational during reporting period | | | | |
| 5.4<br>5.9<br>5.10 | $CA_{flow,i,y}$ | Hourly average flow rate of cooling air sent to a destruction device after the metering point of the ventilation air stream during period y | scfm | Continuously | m, c | Readings taken every two minutes to calculate flow rate per hour; adjusted to standard conditions, if applicable using equation 5.11. If the flow of cooling air is not metered, the maximum capacity of the air intake system must be used for the flow rate. |
| 5.4<br>5.9<br>5.10 | $C_{CH4,exhaust,\ y}$ | Hourly average methane concentration of exhaust gas | scf $CH_4$/scf | Continuously | m, c | Readings taken every two minutes to calculate average methane concentration per hour |
| 5.5<br>5.9 | $VA_{P,i}$ | Volume of ventilation air sent to qualifying and non-qualifying devices for destruction through use i during the reporting period | scf | Continuously | m, c | Adjusted to standard conditions, if applicable, using equation 5.11 |
| 5.5<br>5.9 | $MG_{SUPP,i}$ | Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.11 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) | Comment |
|---|---|---|---|---|---|---|
| | | period | | | | |
| 5.5<br>5.9 | $C_{CH4,MG,t}$ | Daily average methane concentration of mine gas sent with ventilation air to destruction device | scf $CH_4$/scf | Continuously | m, c | Readings taken every 15 minutes to calculate average methane concentration per day |
| 5.5<br>5.9 | $DV_{MG,t}$ | Daily volume of mine gas sent with ventilation air to destruction device | scf | Continuously | m, c | Readings taken every 15 minutes to calculate volume per day; adjusted to standard conditions, if applicable, using equation 5.11 |
| 5.7 | $CONS_{ELEC}$ | Additional electricity consumption for the capture and destruction of methane during the reporting period | MWh | Every reporting period | o | From electricity use records |
| 5.7 | $CONS_{HEAT}$ | Additional heat consumption for the capture and destruction of methane during the reporting period | Volume | Every reporting period | o | From heat use records |
| 5.7 | $CONS_{FF}$ | Additional fossil fuel consumption for the capture and destruction of methane during the reporting period | Volume | Every reporting period | o | From fuel use records |
| 5.9<br>5.10 | $VA_{flow,i,y}$ | Hourly average flow rate of ventilation air sent to a device for destruction through use i during the reporting period | scfm | Continuously | m, c | Readings taken every two minutes to calculate flow rate per hour; adjusted to standard conditions, if applicable |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) | Comment |
|---|---|---|---|---|---|---|
| | | | | | | using equation 5.11. |
| 5.11 | $VA_{actual,y}$ | Measured average flow rate or total volume of ventilation air sent to a destruction device during period y | acfm or acf | Continuously | m, c | Readings taken every two minutes to calculate average flow rate per hour; adjusted to standard conditions, if applicable, using equation 5.11 |
| 5.11 | $T_{VAinflow,y}$ | Measured absolute temperature of ventilation air sent to a destruction device for the time interval y, °R=°F + 459.67 | °R | Continuously | m, c | Readings taken at least every hour to calculate temperature for time interval y |
| 5.11 | $P_{VAinflow,y}$ | Measured absolute pressure of ventilation air sent to a destruction device for the time interval y | atm | Continuously | m, c | Readings taken at least every hour to calculate pressure for time interval y |

### 6.5. Active Underground Mine Methane Drainage Activities

(a) Mine gas from each methane source (i.e., pre-mining surface wells, pre-mining in-mine boreholes, or post-mining gob 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.

(b) The flow rate of MG sent to a destruction device must be measured continuously, recorded every 15 minutes, 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:

(1) 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

(2) 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.

(c) 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:

(1) 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;

(2) 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

(3) 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.

(d) The methane concentration of the mine gas extracted from each methane source must be measured continuously and recorded every 15 minutes to calculate daily average methane concentration.

(e) 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 least every hour to calculate hourly temperature and pressure.

(f) Offset Project Operators or Authorized Project Designees must monitor the parameters prescribed in table 6.2. 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 6.2. Active Underground Mine Methane Drainage Activity Monitoring Parameters**

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| 5.15 5.21 5.22 | $DE_i$ | 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 Executive Officer |
| 5.15 5.16 | $PSW_{B,i}$ | Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.2.1(h). |
| 5.15 5.16 | $PIB_{B,i}$ | Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.2.1(h) |
| 5.15 5.16 | $PGW_{B,i}$ | Volume of MG from post-mining gob wells that would have been | scf | Estimated at offset project commencement; calculated each | m, c | The largest of the three values calculated per |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | sent to non-qualifying devices for destruction through use i during the reporting period | | reporting period if non-qualifying device continues to operate after project start | | section 5.2.1(h) |
| 5.15 5.16 5.21 5.22 | $C_{CH4,t}$ | Daily average methane concentration of mine gas sent to a destruction device | scf $CH_4$/scf | Continuously | m, c | Readings taken every 15 minutes to calculate average methane concentration per day; calculated separately for each methane source |
| 5.15 5.16 5.21 5.22 | $DV_t$ | Daily volume of mine gas sent to a destruction device | scf | Continuously | m, c | Readings taken every 15 minutes to calculate volume per day; adjusted to standard conditions, if applicable, using equation 5.23. Calculated separately for each methane source. |
| 5.16 5.21 5.22 | $PIB_{P,i}$ | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.23 |
| 5.16 5.21 5.22 | $PGW_{P,i}$ | Volume of MG from post-mining gob wells sent to qualifying and non-qualifying | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | devices for destruction through use i during the reporting period | | | | equation 5.23 |
| 5.16 5.21 5.22 | $MG_{SUPP,i}$ | Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.23 |
| 5.16 5.21 5.22 | $C_{CH4,MG,t}$ | Daily average methane concentration of mine gas sent with ventilation air to destruction device | scf $CH_4$/scf | Continuously | m, c | Readings taken every 15 minutes to calculate average methane concentration per day |
| 5.16 5.21 5.22 | $DV_{MG,t}$ | Daily volume of mine gas sent with ventilation air to destruction device | scf | Continuously | m, c | Readings taken every 15 minutes to calculate volume per day; adjusted to standard conditions, if applicable, using equation 5.23 |
| 5.16 | $PSWnqd_i$ | Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.23 |
| 5.17 | $PSWe_{pre,i}$ | Volume of MG sent to qualifying destruction devices, from the beginning of the crediting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.23 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | through the end of the reporting period, captured from pre-mining surface wells that were mined through during the reporting period | | | | |
| 5.17 | $PSWe_{post,i}$ | Volume of MG sent to qualifying destruction devices in the reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.23 |
| 5.19 | $CONS_{ELEC}$ | Additional electricity consumption for the capture and destruction of methane during the reporting period | MWh | Every reporting period | o | From electricity use records |
| 5.19 | $CONS_{HEAT}$ | Additional heat consumption for the capture and destruction of methane during the reporting period | Volume | Every reporting period | o | From heat use records |
| 5.19 | $CONS_{FF}$ | Additional fossil fuel consumption for the capture and destruction of methane during the reporting period | Volume | Every reporting period | o | From fuel use records |
| 5.21 5.22 | $PSW_{P,all,i}$ | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.23 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | during the reporting period. For qualifying devices, all MG must be quantified regardless of whether or not the well is mined through by the end of the reporting period | | | | |
| 5.23 | $MG_{actual,y}$ | Measured average flow rate or total volume of MG sent to a destruction device during time interval y | acfm or acf | Continuously | m | |
| 5.23 | $T_{MG,y}$ | Measured absolute temperature of MG for the time interval y, °R=°F + 459.67 | °R | Continuously | m, c | Readings taken at least every hour to calculate temperature for time interval y |
| 5.23 | $P_{MG,y}$ | Measured absolute pressure of MG for the time interval y | atm | Continuously | m, c | Readings taken at least every hour to calculate pressure for time interval y |

### 6.6. Active Surface Mine Methane Drainage Activities

(a) Mine gas from each methane source (i.e., pre-mining surface wells, pre-mining in-mine boreholes, 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.

(b) The flow rate of MG sent to a destruction device must be measured continuously, recorded every 15 minutes, 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:

(1) 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

(2) 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.

(c) 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:

(1) 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;

(2) 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

(3) 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.

(d) The methane concentration of the SMM extracted from each methane source must be measured continuously and recorded every 15 minutes to calculate daily average methane concentration.

(e) 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 least every hour to calculate hourly temperature and pressure.

(f) Offset Project Operators or Authorized Project Designees must monitor the parameters prescribed in table 6.3. 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 6.3. Active Surface Mine Methane Drainage Activity Monitoring Parameters**

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| 5.27 5.36 5.37 | $DE_i$ | 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 Executive Officer |
| 5.27 5.28 | $PSW_{B,i}$ | Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.3.1(h) |
| 5.27 5.28 | $PIB_{B,i}$ | Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.3.1(h) |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| 5.27 5.28 | $ECW_{B,i}$ | Volume of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.3.1(h) |
| 5.27 5.28 | $AWR_{B,i}$ | Volume of MG from abandoned wells that are reactivated that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.3.1(h) |
| 5.27 5.28 | $CDW_{B,i}$ | Volume of MG from converted dewatering wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.3.1(h) |
| 5.27 5.28 5.36 5.37 | $C_{CH4,t}$ | Daily average methane concentration of mine gas sent to a destruction device | scf $CH_4$/scf | Continuously | m, c | Readings taken every 15 minutes to calculate average methane concentration per day; calculated separately for |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | | | | | each methane source |
| 5.27 5.28 5.36 5.37 | $DV_t$ | Daily volume of mine gas sent to a destruction device | scf | Continuously | m, c | Readings taken every 15 minutes to calculate volume per day; adjusted to standard conditions, if applicable using equation 5.23. Calculated separately for each methane source. |
| 5.28 5.36 5.37 | $PIB_{P,i}$ | Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.28 | $PSWnqd_i$ | Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.28 | $ECWnqd_i$ | Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | mining sent to non-qualifying devices for destruction through use i during the reporting period | | | | |
| 5.28 | $AWRnqd_i$ | Volume of MG from abandoned wells that are reactivated sent to non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.28 | $CDWnqd_i$ | Volume of MG from converted dewatering wells sent to non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.29 | $PSWe_{pre,i}$ | Volume of MG sent to qualifying destruction devices, 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 | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.29 | $PSWe_{post,i}$ | Volume of MG sent to qualifying destruction devices in the reporting period captured from pre-mining surface wells that were mined | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | through during earlier reporting periods | | | | |
| 5.30 | $ECWe_{pre,i}$ | Volume of MG sent to qualifying destruction devices, from the beginning of the crediting period through the end of the reporting period, captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.30 | $ECWe_{post,i}$ | Volume of MG sent to qualifying destruction devices in the reporting period captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during earlier reporting periods | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.31 | $AWRe_{pre,i}$ | Volume of MG sent to qualifying destruction devices, from the beginning of the crediting period through the end of the reporting | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | period, captured from abandoned wells that are reactivated that were mined through during the reporting period | | | | |
| 5.31 | $AWRe_{post,i}$ | Volume of MG sent to qualifying destruction devices in the reporting period captured from abandoned wells that are reactivated that were mined through during earlier reporting periods | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.32 | $CDWe_{pre,i}$ | Volume of MG sent to qualifying destruction devices, 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 | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.32 | $CDWe_{post,i}$ | Volume of MG sent to qualifying destruction devices in the reporting period captured from converted dewatering wells that were mined through during earlier reporting periods | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.34 | $CONS_{ELEC}$ | Additional electricity consumption for | MWh | Every reporting period | o | From electricity use records |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | the capture and destruction of methane during the reporting period | | | | |
| 5.34 | $CONS_{HEAT}$ | Additional heat consumption for the capture and destruction of methane during the reporting period | Volume | Every reporting period | o | From heat use records |
| 5.34 | $CONS_{FF}$ | Additional fossil fuel consumption for the capture and destruction of methane during the reporting period | Volume | Every reporting period | o | From fuel use records |
| 5.36 5.37 | $PSW_{P,all,i}$ | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG must be quantified regardless of whether or not the well is mined through by the end of the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.36 5.37 | $ECW_{P,all,i}$ | Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG must be quantified regardless of whether or not the well is mined through by the end of the reporting period | | | | |
| 5.36 5.37 | $AWR_{P,all,i}$ | Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG must be quantified regardless of whether or not the well is mined through by the end of the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |
| 5.36 5.37 | $CDW_{P,all,i}$ | Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.38 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | must be quantified regardless of whether or not the well is mined through by the end of the reporting period | | | | |
| 5.38 | $MG_{actual,y}$ | Measured average flow rate or total volume of MG sent to a destruction device during time interval y | acfm or acf | Continuously | m | |
| 5.38 | $T_{MG,y}$ | Measured absolute temperature of MG for the time interval y, °R=°F +459.67 | °R | Continuously | m, c | Readings taken at least every hour to calculate temperature for time interval y |
| 5.38 | $P_{MG,y}$ | Measured absolute pressure of MG for the time interval y | atm | Continuously | m, c | Readings taken at least every hour to calculate pressure for time interval y |

### 6.7. Abandoned Underground Mine Methane Recovery Activities

(a) Mine gas from each methane source (i.e., pre-mining surface wells drilled into the mine during active mining operations, pre-mining in-mine boreholes drilled into the mine during active mining operations, post-mining gob wells drilled into the mine during active mining operations, and newly drilled surface 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.

(b) The flow rate of MG sent to a destruction device must be measured continuously, recorded every 15 minutes, 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:

(1) 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

(2) 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.

(c) 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:

(1) 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;

(2) 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

(3) 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.

(d) The methane concentration of the MG extracted from each methane source must be measured continuously and recorded every 15 minutes to calculate daily average methane concentration.

(e) 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 least every hour to calculate hourly temperature and pressure.

(f) Offset Project Operators or Authorized Project Designees that elect to seek written approval from the Executive Officer to derive mine-specific hyperbolic emission rate decline curve coefficients using measured data from pre-existing wells or boreholes open to the atmosphere and natural gas seeps, rather than using default decline curve coefficients in table 5.1, must adhere to the following:

(1) Offset Project Operators and Authorized Project Designees must monitor the:

(A) MG flow rates;

(B) local barometric pressure; and

(C) methane concentration of MG.

(2) Data must be monitored over a 72 hour period on at least three separate occasions each separated by a minimum of 90 days.

(3) MG flow rates and the barometric pressure must be monitored continuously and recorded at least on an hourly basis.

(4) Methane concentration must be measured at least daily.

(g) Offset Project Operators and Authorized Project Designees must monitor the parameters prescribed in table 6.4. 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 6.4. Abandoned Underground Mine Methane Recovery Activity Monitoring Parameters**

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| 5.42<br>5.48<br>5.49 | $DE_i$ | 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 Executive Officer. |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| 5.42 | $PSW_{B,i}$ | Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.4.1(i). |
| 5.42 | $PIB_{B,i}$ | Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.4.1(i). |
| 5.42 | $PGW_{B,i}$ | Volume of MG from post-mining gob wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.4.1(i). |
| 5.42 | $NSW_{B,i}$ | Volume of MG from newly drilled surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period | scf | Estimated at offset project commencement; calculated each reporting period if non-qualifying device continues to operate after project start | m, c | The largest of the three values calculated per section 5.4.1(i). |
| 5.42<br>5.48<br>5.49 | $C_{CH4,t}$ | Daily average methane concentration of mine gas sent to a destruction device | scf $CH_4$/scf | Continuously | m, c | Readings taken every 15 minutes to calculate average methane |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | | | | | concentration per day; calculated separately for each methane source |
| 5.42 5.48 5.49 | $DV_t$ | Daily volume of mine gas sent to a destruction device | scf | Continuously | m, c | Readings taken every 15 minutes to calculate volume per day; adjusted to standard conditions, if applicable, using equation 5.50. Calculated separately for each methane source. |
| 5.44 | $ER_{AMM}$ | Average ventilation air emission rate over the life of the mine calculated using available data collected by MSHA | Mscf/d | At offset project commencement | o | Available from MSHA |
| 5.44 | t | Time elapsed from the date of mine closure to midpoint of the reporting period | days | At offset project commencement | o | Available from public agency (i.e., MSHA, EPA) |
| 5.44 | $RP_{days}$ | Days in reporting period | days | Each reporting period | o | |
| 5.46 | $CONS_{ELEC}$ | Additional electricity consumption for the capture and destruction of methane during the reporting period | MWh | Every reporting period | o | From electricity use records |
| 5.46 | $CONS_{HEAT}$ | Additional heat consumption for | Volume | Every reporting period | o | From heat use records |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | the capture and destruction of methane during the reporting period | | | | |
| 5.46 | $CONS_{FF}$ | Additional fossil fuel consumption for the capture and destruction of methane during the reporting period | Volume | Every reporting period | o | From fuel use records |
| 5.48 5.49 | $PSW_{P,i}$ | Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.50 |
| 5.48 5.49 | $PIB_{P,i}$ | Volume of MG from pre-mining in-mine boreholes sent to by qualifying and non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.50 |
| 5.48 5.49 | $PGW_{P,i}$ | Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.50 |
| 5.48 5.49 | $NSW_{P,i}$ | Volume of MG from newly drilled surface wells sent to qualifying and non-qualifying devices for | scf | Every reporting period | m, c | Adjusted to standard conditions, if applicable, using equation 5.50 |

| Eq. # | Parameter | Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) Operating Records (o) Reference (r) | Comment |
|---|---|---|---|---|---|---|
| | | destruction through use i during the reporting period | | | | |
| 5.50 | $MG_{actual,y}$ | Measured average flow rate or total volume of MG sent to a destruction device during time interval y | acfm or acf | Continuously | m | |
| 5.50 | $T_{MG,y}$ | Measured absolute temperature of MG for the time interval y, °R=°F + 459.67 | °R | Continuously | m, c | Readings taken at least every hour to calculate temperature for time interval y |
| 5.50 | $P_{MG,y}$ | Measured absolute pressure of MG for the time interval y | atm | Continuously | m, c | Readings taken at least every hour to calculate pressure for time interval y |

| Monitoring Parameters for Deriving Mine-Specific Hyperbolic Emission Rate Decline Curve Coefficients | | | | |
|---|---|---|---|---|
| Description | Data Unit | Measurement Frequency | Measured (m) Calculated (c) | Comment |
| MG flow rate | Mscf/d | Continuously | m, c | Recordings taken at least on an hourly basis during the monitoring period |
| Local barometric pressure | atm | Continuously | m | Recordings taken at least on an hourly basis during the monitoring period |
| Measured methane concentration of mine gas captured from methane source | scf $CH_4$/scf | Continuously | m | Readings taken at least daily during the monitoring period |

## Chapter 7. Reporting

In addition to the offset project requirements set forth in sections 95975 and 95976 the Regulation, mine methane capture offset projects must adhere to the project listing and reporting eligibility requirements below.

### 7.1. Listing Requirements

(a) Listing information must be submitted by the Offset Project Operator or Authorized Project Designee no later than the date on which the Offset Project Operator or Authorized Project Designee submits the first Offset Project Data Report.

(b) In order for a mine methane capture Compliance Offset Project to be listed, the Offset Project Operator or Authorized Project Designee must submit the information required by section 95975 the Regulation, in addition to the following information:

(1) Offset project name.

(2) Mine methane capture activity type (i.e., active underground mine VAM activity, active underground mine methane drainage activity, active surface mine methane drainage activity, or abandoned underground mine methane recovery activity).

(3) Contact information including name, phone number, mailing address, physical address (if different from mailing address), email address, and, if applicable, organizational affiliation for the:

(A) Offset Project Operator;

(B) Authorized Project Designee (if applicable);

(C) The person submitting the information; and

(D) Any technical consultants.

(4) CITSS ID number for the:

(A) Offset Project Operator; and

(B) Authorized Project Designee (if applicable).

(5) Date of form completion.

(6) *Name and mailing address of mine owner(s) and parent company(ies), if different from mine owner.

(7) *Name of surface owner(s), if different from mine owner.

(8) *Name and mailing address of mine methane owner(s), if different from mine owner.

(9) *Name and mailing address of mine operator(s), if different from mine owner.

(10) *Name and mailing address of methane destruction system owner(s), if different from mine owner, Offset Project Operator, or Authorized Project Designee.

(11) Other parties with a material interest in the mine methane.

(12) A description of the mine and resource ownership and operation structures.

(13) *Documentation showing the Offset Project Operator's legal authority to implement the offset project (e.g., title report, coal lease, gas lease, permit, or contract agreement).

(14) *Latitude and longitude coordinates and physical address (if available) of mine site.

(15) *Indicate if the project occurs on private or public lands and further specify if the project occurs on any of the following categories of land:

(A) Land that is owned by, or subject to an ownership or possessory interest of a Tribe;

(B) Land that is "Indian lands" of a Tribe, as defined by 25 U.S.C. §81(a)(1); or

(C) Land that is owned by any person, entity, or Tribe, within the external borders of such Indian lands.

(16) *If the project is located on one the above categories of land, a description and copies of documentation demonstrating that the land is owned by (or subject to an ownership or possessory interest of) a tribe or private entities.

(17) *MSHA mine identification number.

(18) *MSHA classifications.

(A) Coal or metal and nonmetal;

(B) Underground or surface; and

(C) Active or abandoned.

(19) Mine basin as defined by AAPG Geologic Note: AAPG-CSD Geological Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laurie G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991).

(20) *Mining method(s) employed (e.g., longwall, room and pillar, or open-pit).

(21) *Average annual mineral production (specify mineral produced and unit).

(22) *Year of initial production.

(23) *Year of closure (estimate if mine is not yet closed).

(24) Name of state and/or federal agency(ies) responsible for issuing mine leases and/or permits.

(25) List any permits obtained, or to be obtained, to build and operate the project.

(26) Offset project commencement date and specification of the action(s) that identify the commencement date.

(27) First reporting period.

(28) A qualitative characterization and quantitative estimate of the baseline emissions at the mine including an explanation of how the quantitative estimate was reached.

(29) Describe any mine methane destruction occurring at the mine prior to the offset project commencement date. List the source of the methane destroyed, destruction device(s) used, and device operation dates.

(30) A description of the project activities that will lead to GHG emission reductions including the methane end-use management option(s), destruction devices, and metering and data collection systems to be employed by the project.

(31) Declaration that the project is not being implemented as a result of any federal, state or local law, statute, regulation, court order, or other legally binding mandate.

(32) *Disclose if any GHG reductions associated with the offset project have ever been registered with or claimed by another registry or program, or sold to a third party prior to our listing. Identify the registry or program as well as the vintage(s) of credits issued, reporting period(s), and verification bodies that have performed verification services.

(33) State whether the project is transitioning to the Compliance Offset Protocol Mine Methane Capture Projects, after previously being listed as an early action offset project.

(34) *Bird's-eye view map of the mine site that includes:

(A) Longitude and latitude coordinates;

(B) Governing jurisdictions;

(C) Public and private roads;

(D) Mine permit boundary; and

(E) Mine lease boundary, if applicable.

(35) For active underground mine VAM activities, a diagram of the project site that includes:

(A) Location of ventilation shafts included in the project. Assign a number to each piece of equipment and, on a separate sheet of paper:

1. Indicate whether the ventilation shaft is currently existing or planned; and

2. Indicate whether or not the ventilation shaft was connected to a non-qualifying destruction device at any point during the year prior to offset project commencement.

(B) Location of equipment used to collect, treat, store, meter, and destroy ventilation air methane in use prior to offset project commencement. Assign a number to each piece of equipment and, on a separate sheet of paper:

1. Indicate whether or not the piece of equipment will be part of the project;

2. Provide a description, including the purpose, of the piece of equipment;

3. For destruction devices, provide the operation dates (approximate dates are acceptable);

3. For destruction devices, indicate whether it is a qualifying or non-qualifying destruction device in accordance with chapter 2;

4. For non-qualifying destruction devices that were operating at the mine prior to offset project commencement and during the year immediately preceding offset project commencement, provide the volume or mass of ventilation air sent to the device during the three-year period prior to offset project commencement (or during the length of time the device is operational, if less than three years), adjusted for temperature and pressure using equation 5.11, if applicable, averaged according to the length of the initial reporting period; and

5. For non-qualifying destruction devices that were operating at the mine prior to offset project commencement and during the year immediately preceding offset project commencement, provide the volume or mass of ventilation air sent to the device during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using equation 5.11, if applicable, and averaged according to the length of the initial reporting period.

(C) Location of equipment used to collect, treat, store, meter, and destroy ventilation air methane installed as part of the project. Assign a number to each piece of equipment and, on a separate sheet of paper:

1. Provide a description, including the purpose, of the piece of equipment;
2. For destruction devices, provide the operational date or expected operational date (approximate dates are acceptable); and
3. For destruction devices, indicate whether it is a qualifying or non-qualifying destruction device in accordance with chapter 2.

(36) *For active underground mine methane drainage activities, active surface mine methane drainage activities, and abandoned underground mine methane recovery activities, a diagram of the project site that includes:

(A) Location of wells and boreholes included in the project. Assign a number to each piece of equipment and, on a separate sheet of paper:

1. Indicate whether the well/borehole is currently existing or planned;
2. Indicate whether or not the well/borehole was connected to a non-qualifying destruction device at any point during the year prior to offset project commencement;
3. Indicate the methane source type (i.e., pre-mining surface well, pre-mining in-mine borehole, post-mining gob well, existing CBM well that would otherwise be shut-in and abandoned, abandoned well that is reactivated, or converted dewatering wells); and
4. For pre-mining surface wells, indicate whether or not the well is mined through, and when the well was, or is expected to be, mined through.

(B) Location of equipment used to collect, treat, store, meter, and destroy MM/SMM/AMM in use prior to offset project commencement. Assign a number to each piece of equipment and, on a separate sheet of paper:

1. Indicate whether or not the piece of equipment will be part of the project;
2. Provide a description, including the purpose, of the piece of equipment;
3. For destruction devices, provide the operation dates (approximate dates are acceptable);
4. For destruction devices, indicate whether it is a qualifying or non-qualifying destruction device in accordance with chapter 2;
5. For non-qualifying destruction devices that were operating at the mine prior to offset project commencement and during the year immediately preceding offset project commencement, provide the volume or mass of mine gas sent to the device during the three-year period prior to offset project commencement (or during the length of time the device is operational, if less than three years), adjusted for temperature and pressure using equation 5.11, if applicable, averaged according to the length of the initial reporting period; and
6. For non-qualifying destruction devices that were operating at the mine prior to offset project commencement and during the year immediately preceding offset project commencement, provide the volume or mass of mine gas sent to the device during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using equation 5.11, if applicable, and averaged according to the length of the initial reporting period.

(C) Location of equipment used to collect, treat, store, meter, and destroy MM/SMM/AMM installed as part of the project. Assign a number to each piece of equipment and, on a separate sheet of paper:

1. Provide a description, including the purpose, of the piece of equipment;
2. For destruction devices, provide the operational date or expected operational date (approximate dates are acceptable); and
3. For destruction devices, indicate whether it is a qualifying or non-qualifying destruction device in accordance with chapter 2.

(c) Abandoned mine methane recovery activities that are comprised of multiple mines as allowed for by section 2.4 must provide the items in section 7.1(b) marked with an asterisk (*) for each involved mine.

### 7.2. Offset Project Data Report

(a) Offset Project Operators or Authorized Project Designees must submit an OPDR at the conclusion of each Reporting Period according to the reporting schedule in section 95976 of the Regulation.

(b) Offset Project Operators or Authorized Project Designees must submit the information required by section 95976 of the Regulation, in addition to the following information:

(1) Offset project name.

(2) ARB project ID number.

(3) Mine methane capture activity type (i.e., active underground mine VAM activity, active underground mine methane drainage activity, active surface mine methane drainage activity, or abandoned underground mine methane recovery activity).

(4) Contact information including name, phone number, mailing address, physical address (if different from mailing address), email address, and, if applicable, organizational affiliation for the:

(A) Offset Project Operator;

(B) Authorized Project Designee (if applicable);

(C) The person submitting the information; and

(D) Any technical consultants.

(5) CITSS ID number for the:

(A) Offset Project Operator; and

(B) Authorized Project Designee (if applicable).

(6) Date of form completion.

(7) Reporting period.

(8) Offset project commencement date.

(9) *Mining method(s) (e.g., longwall, room and pillar, or open-pit) employed during reporting period. For abandoned underground mine methane recovery activities, mining method(s) employed while mine was active.

(10) Mineral production during reporting period (specify mineral produced and unit).

(11) Statement as to whether all the information submitted for project listing is still accurate. If not, provide updates to relevant listing information.

(12) *Statement as to whether the project has met all local, state, or federal regulatory requirements during the reporting period. If not, an explanation of the non-compliance must be provided.

(13) For active underground mine VAM activities, provide the:

(A) Emission reductions achieved by the project during the reporting period (ER);

(B) Volume of ventilation air that would have been sent to non-qualifying devices for destruction through use i during the reporting period ($VA_{B,i}$);

(C) Volume of ventilation air sent to qualifying and non-qualifying devices for destruction through use i during the reporting period ($VA_{P,i}$), reported separately for each destruction device;

(D) Weighted average of measured methane concentration of ventilation air sent to destruction devices during the reporting period ($C_{CH4}$), reported separately for the baseline and project scenarios;

(E) Hours during which destruction device was operational during reporting period (y), reported separately for each destruction device in the baseline and project scenarios;

(F) Hourly average flow rate of ventilation air sent to a device for destruction through use i during the reporting period ($VA_{flow,i,y}$), reported separately for each destruction device in the baseline and project scenarios;

(G) Hourly average flow rate of cooling air sent to a destruction device after the metering point of the ventilation air stream during period y ($CA_{flow,i,y}$), reported separately for each destruction device in the baseline and project scenarios, indicating whether flow rate was monitored or if default maximum quantity was used;

(H) Weighted average of measured methane concentration of exhaust gas emitted from destruction device during the reporting period ($C_{CH4,exhaust,i}$), reported separately for each destruction device in the baseline and project scenarios;

(I) Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period ($MG_{SUPP,i}$), reported separately for each destruction device in the baseline and project scenarios;

(J) Weighted average of measured methane concentration of captured mine gas sent to qualifying and non-qualifying destruction devices with ventilation air during the reporting period ($C_{CH4,MG}$), reported separately for each destruction device in the baseline and project scenarios; and

(K) Quantities of additional electricity ($CONS_{ELEC}$), heat ($CONS_{HEAT}$), and fossil fuels ($CONS_{FF}$) consumed by the project and the $CO_2$ emission factors ($CEF_{ELEC}$), ($CEF_{HEAT}$), and ($CEF_{FF}$) applied.

(14) For active underground mine methane drainage activities, provide the:

(A) Emission reductions achieved by the project during the reporting period (ER);

(B) Volume of mine gas that would have been sent to non-qualifying devices for destruction through use i during the reporting period, ($PSW_{B,i,}$ $PIB_{B,i,}$ $PGW_{B,i}$) reported separately for each methane source and destruction device;

(C) Volume of mine gas sent to qualifying and non-qualifying devices for destruction through use i during the reporting period ($PSW_{P,i,}$ $PIB_{P,i,}$ $PGW_{P,i}$), reported separately for each methane source and destruction device;

(D) Weighted average of measured methane concentration of mine gas sent to destruction devices during the reporting period ($C_{CH4}$) reported separately for each methane source in the baseline and project scenarios;

(E) For pre-mining surface wells, identify all wells included in the project that were mined through during the reporting period and provide the values used for the following terms: $PSWnqd_i$, $PSWe_{pre,i}$, $PSWe_{post,i}$, and $PSW_{P,all,i}$;

(F) Volume of mine gas extracted from a methane drainage system and sent with ventilation air to qualifying and non-qualifying devices for destruction during the reporting period ($MG_{SUPP,i}$), reported separately for the baseline and project scenarios;

(G) Weighted average of measured methane concentration of captured mine gas sent with ventilation air to qualifying and non-qualifying destruction devices during the reporting period ($C_{CH4,MG}$), reported separately for the baseline and project scenarios;

(H) Any site-specific methane destruction efficiencies used and a description of the process of establishing these methane destruction efficiencies that includes the identity of any third parties involved; and

(I) Quantities of additional electricity ($CONS_{ELEC}$), heat ($CONS_{HEAT}$), and fossil fuels ($CONS_{FF}$) consumed by the project and the $CO_2$ emission factors ($CEF_{ELEC}$), ($CEF_{HEAT}$), and ($CEF_{FF}$) applied.

(15) For active surface mine methane drainage activities, provide the:

(A) Emission reductions achieved by the project during the reporting period (ER);

(B) Volume of mine gas that would have been sent to non-qualifying devices for destruction through use i during the reporting period ($PSW_{B,i,}$ $PIB_{B,i,}$ $ECW_{B,i,}$ $AWR_{B,i,}$ $CDW_{B,i}$), reported separately for each methane source and destruction device;

(C) Volume of mine gas sent to qualifying and non-qualifying devices for destruction through use i during the reporting period ($PSW_{P,i,}$ $PIB_{P,i,}$ $ECW_{P,i,}$ $AWR_{P,i,}$ $CDW_{P,i}$), reported separately for each methane source and destruction device;

(D) Weighted average of measured methane concentration of mine gas sent to destruction devices during the reporting period ($C_{CH4}$), reported separately for each methane source and destruction device in the baseline and project scenario;

(E) For pre-mining surface wells, identify all wells included in the project that were mined through during the reporting period and provide the values used for the following terms: $PSWnqd_i$, $PSWe_{pre,i}$, $PSWe_{post,i}$, and $PSW_{P,all,i}$;

(F) For existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining, identify all wells included in the project that were mined through during the reporting period and provide the values used for the following terms: $ECWnqd_i$, $ECWe_{pre,i}$, $ECWe_{post,i}$, and $ECW_{P,all,i}$;

(G) For abandoned wells that are reactivated, identify all wells included in the project that were mined through during the reporting period and provide the values used for the following terms: $AWRnqd_i$, $AWRe_{pre,i}$, $AWRe_{post,i}$, and $AWR_{P,all,i}$;

(H) For converted dewatering wells that are reactivated, identify all wells included in the project that were mined through during the reporting period and provide the values used for the following terms: $CDWnqd_i$, $CDWe_{pre,i}$, $CDWe_{post,i}$, and $CDW_{P,all,i}$;

(I) Any site-specific methane destruction efficiencies used and a description of the process of establishing these methane destruction efficiencies that includes the identity of any third parties involved; and

(J) Quantities of additional electricity ($CONS_{ELEC}$), heat ($CONS_{HEAT}$), and fossil fuels ($CONS_{FF}$) consumed by the project and the $CO_2$ emission factors ($CEF_{ELEC}$), ($CEF_{HEAT}$), and ($CEF_{FF}$) applied.

(16) For abandoned underground mine methane recovery activities, provide the:

(A) Emission reductions achieved by the project during the reporting period (ER);

(B) Volume of mine gas that would have been sent to non-qualifying devices for destruction through use i during the reporting period ($PSW_{B,i,}$ $PIB_{B,i,}$ $ECW_{B,i,}$ $AWR_{B,i,}$ $CDW_{B,i}$), reported separately for each methane source and destruction device;

(C) Volume of mine gas sent to qualifying and non-qualifying devices for destruction through use i during the reporting period ($PSW_{P,i,}$ $PIB_{P,i,}$ $ECW_{P,i,}$ $AWR_{P,i,}$ $CDW_{P,i}$), reported separately for each methane source and destruction device;

(D) Weighted average of measured methane concentration of mine gas sent to destruction devices during the reporting period ($C_{CH4}$), reported separately for each methane source in the baseline and project scenarios;

(E) Any site-specific methane destruction efficiencies used and a description of the process of establishing these methane destruction efficiencies that includes the identity of any third parties involved; and

(F) Quantities of additional electricity ($CONS_{ELEC}$), heat ($CONS_{HEAT}$), and fossil fuels ($CONS_{FF}$) consumed by the project and the $CO_2$ emission factors ($CEF_{ELEC}$), ($CEF_{HEAT}$), and ($CEF_{FF}$) applied.

(c) Abandoned mine methane recovery activities that are comprised of multiple mines as allowed for by section 2.4 must provide the items in section 7.2(b) marked with an asterisk (*) for each involved mine.

**Chapter 8. Verification**

(a) All Offset Project Data Reports are subject to regulatory verification as set forth in section 95977 of the Regulation by an ARB accredited offset verification body.

(b) The Offset Project Data Reports must receive a positive or qualified positive verification statement to be issued ARB or registry offset credits.

(c) Offset Project Operators or Authorized Project Designees are responsible for producing mine and project records requested by the offset project verifier, which could include, but is not limited to, the following:

(1) Mine plans;

(2) Mine ventilation plans;

(3) Mine maps;

(4) Mine operating permits, leases (if applicable), and air, water, and land use permits;

(5) Inspection, cleaning, and calibration records for metering equipment; and

(6) Source testing records for destruction devices that use site-specific methane destruction efficiencies.

## Appendix A. Emission Factors – Quantification Methodology

### Table A.1 $CO_2$ 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) | $1.028 \times 10^{-3}$ | 53.02 | 0.055 |
| **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 |
| 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 |
| **Other fuels (solid)** | **MMBtu / short ton** | **kg $CO_2$ / MMBtu** | **kg $CO_2$ / short ton** |
| Municipal Solid Waste | 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 | $0.092 \times 10^{-3}$ | 274.32 | 0.025 |
| Coke Oven Gas | $0.599 \times 10^{-3}$ | 46.85 | 0.028 |
| Propane Gas | $2.516 \times 10^{-3}$ | 61.46 | 0.155 |
| Fuel Gas | $1.388 \times 10^{-3}$ | 59.00 | 0.082 |
| **Biomass Fuels (solid)** | **MMBtu / short ton** | **kg CO2 / 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 CO2 / MMBtu** | **kg $CO_2$ / scf** |
| Biogas (Captured methane) | 0.841 x 10-3 | 52.07 | 0.044 |
| **Biomass Fuels (liquid)** | **MMBtu / gallon** | **kg CO2 / 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) (2013) http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/subpart_c_rule_part98.pdf.

**Table A.2 Emissions & Generation Resource Integrated Database (eGRID) Table**

| eGRID Subregion Acronym | eGRID Subregion Name | Annual Output Emission Rates | |
|---|---|---|---|
| | | (lb $CO_2$/MWh) | (metric ton $CO_2$/MWh)* |
| AKGD | ASCC Alaska Grid | 1,280.86 | 0.581 |
| AKMS | ASCC Miscellaneous | 521.26 | 0.236 |
| AZNM | WECC Southwest | 1,191.35 | 0.540 |
| CAMX | WECC California | 658.68 | 0.299 |
| ERCT | ERCOT All | 1,181.73 | 0.536 |
| FRCC | FRCC All | 1,176.61 | 0.534 |
| HIMS | HICC Miscellaneous | 1,351.66 | 0.613 |
| HIOA | HICC Oahu | 1,593.35 | 0.723 |
| MORE | MRO East | 1,591.65 | 0.722 |
| MROW | MRO West | 1,628.60 | 0.739 |
| NEWE | NPCC New England | 728.41 | 0.330 |
| NWPP | WECC Northwest | 819.21 | 0.372 |
| NYCW | NPCC NYC/Westchester | 610.67 | 0.277 |
| NYLI | NPCC Long Island | 1,347.99 | 0.611 |
| NYUP | NPCC Upstate NY | 497.92 | 0.226 |
| RFCE | RFC East | 947.42 | 0.430 |
| RFCM | RFC Michigan | 1,659.46 | 0.753 |
| RFCW | RFC West | 1,520.59 | 0.690 |
| RMPA | WECC Rockies | 1,824.51 | 0.828 |
| SPNO | SPP North | 1,815.76 | 0.824 |
| SPSO | SPP South | 1,599.02 | 0.725 |
| SRMV | SERC Mississippi Valley | 1,002.41 | 0.455 |
| SRMW | SERC Midwest | 1,749.75 | 0.794 |
| SRSO | SERC South | 1,325.68 | 0.601 |
| SRTV | SERC Tennessee Valley | 1,357.71 | 0.616 |
| SRVC | SERC Virginia/Carolina | 1,035.87 | 0.470 |
| **U.S.** | | **1,216.18** | **0.552** |

Source: U.S. EPA eGRID2012, Version 1.0 Year 2009 GHG Annual Output Emission Rates (Created April 2012)
http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf.
*Converted from lbs $CO_2$/MWh to metric tons $CO_2$/MWh using conversion factor 1 metric ton = 2,204.62 lbs.

**Equation A.1: Calculating Heat Generation Emission Factor**

$$CEFheat = \frac{CEF_{CO2,i}}{Eff_{heat}} \times \frac{44}{12}$$

*Where,*

| | | |
|---|---|---|
| $CEF_{heat}$ | = | $CO_2$ emission factor for heat generation |
| $CEF_{CO2,i}$ | = | $CO_2$ emission factor of fuel used in heat generation (see table A.1) |
| $Eff_{heat}$ | = | 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 |

## Appendix B. Device Destruction Efficiencies – Quantification Methodology

**Table B.1 Default Methane Destruction Efficiencies by Destruction Device**

| Destruction Device | Destruction Efficiency |
|---|---|
| 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. Data Substitution Methodology – Quantification Methodology

(a) ARB expects that MMC projects will have continuous, uninterrupted data for the entire reporting period. However, ARB recognizes that unexpected events or occurrences may result in brief data gaps.

(b) 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.

(c) This methodology is only applicable to 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.

(d) This methodology may be used for missing temperature and pressure data used to adjust flow rates to standard conditions.

(e) 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.

(f) Data substitution is not allowed for data used to calculate mine specific hyperbolic emission rate decline curve coefficients for an abandoned underground mine methane recovery activity.

(g) Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited.

(h) 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:

    (1) Proper functioning can be evidenced by thermocouple readings for flares or engines, energy output for engines, etc.

    (2) For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.

    (3) For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

(i) 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 C.1**

| Duration of Missing Data | Substitution Methodology |
|---|---|
| Less than six hours | Use the average of the four hours of normal operation immediately before and following the outage |
| Six to 24 hours | Use the 90% lower confidence limit of the 24 hours of normal operation prior to and after the outage |
| One to seven days | Use the 95% lower confidence limit of the 72 hours of normal operation prior to and after the outage |
| Greater than one week | No data may be substituted and no credits may be generated |

CLIMATE ACTION RESERVE

# Nitric Acid Production Project Protocol V2.1

Protocol Summary

## Project Definition

The installation of nitrous oxide ($N_2O$) abatement technology at an existing, upgraded and/or relocated nitric acid plant (NAP) that results in the reduction of $N_2O$ emissions that would otherwise have been vented to the atmosphere. A facility may contain more than one project if it contains multiple nitric acid plants.

**Includes:**

- A secondary catalyst project that installs a dedicated $N_2O$ abatement catalyst inside or immediately below the ammonia oxidation reactor
- A tertiary catalyst project that installs a dedicated $N_2O$ abatement catalyst in the tail gas leaving the absorption tower
    - The $N_2O$ abatement technology can either be catalytic decomposition or a non-selective catalytic reduction (NSCR) nitrogen oxide (NOx) abatement technology used to reduce $N_2O$ along with NOx
    - Projects located at an NAP with an existing NSCR unit may install a new tertiary catalyst in the tail gas leaving the NSCR unit; the unit must remain in operation throughout the life of the project

## Project Eligibility Requirements

**Location:** Project must be within the U.S. and its territories.

**Start Date:** Project must be submitted no more than six months after the project start date.

**Performance Standard Test:** By installing one of the following $N_2O$ abatement systems, the project passes the Performance Standard Test:

- A secondary $N_2O$ abatement catalyst
- A tertiary $N_2O$ abatement catalyst, including catalytic decomposition or NSCR

**Legal Requirement Test:** Project developer attests that there are no legal requirements for abatement of $N_2O$ at the project site and must sign the Attestation of Voluntary Implementation. The project is subject to a review of the Legal Requirement Test for each verification period.

**Regulatory Compliance:** Project activities and project NAP must be in material compliance with all applicable federal, state and local regulations. Project developer must sign the Attestation of Regulatory Compliance for each verification period.

**Crediting Period:** Project is eligible to receive credits for 10 years from start date or until the project activity is required by law. Project may apply for a second 10-year crediting period.

**Reporting and Verification Schedule:** Annual verification at a minimum; reporting period cannot be longer than 12 months. Sub-annual and sub-campaign reporting and verification are allowed.

**Other Eligibility Requirements:**

- Clear ownership of greenhouse gas (GHG) emissions reductions must be established
- Project must not be registered with any other registry for the same vintages of reductions
- Project must conduct proper accounting and monitoring

## Project Is Ineligible If:

- The nitric acid plant restarted after December 2, 2007 after being idle for more than 24 months
- The nitric acid plant was constructed after December 2, 2009, unless construction permit was obtained before this date

*Important Note: This is a summary of the protocol. Please read the full protocol for a complete description of project requirements.*

601 W. 5th Street, Suite 650
Los Angeles, California 90071
www.climateactionreserve.org
T: (213) 891 1444

# Nitric Acid Production Project Protocol Version 2.1

## ERRATA AND CLARIFICATIONS

The Climate Action Reserve (Reserve) published its Nitric Acid Production Project Protocol Version 2.1 in June 2016. While the Reserve intends for the Nitric Acid Production Project Protocol V2.1 to be a complete, transparent document, it recognizes that correction of errors and clarifications will be necessary as the protocol is implemented and issues are identified. This document is an official record of all errata and clarifications applicable to the Nitric Acid Production Project Protocol V2.1.[1]

Per the Reserve's Program Manual, both errata and clarifications are considered effective on the date they are first posted on the Reserve website. The effective date of each erratum or clarification is clearly designated below. All listed and registered nitric acid production projects must incorporate and adhere to these errata and clarifications when they undergo verification. The Reserve will incorporate both errata and clarifications into future versions of the protocol.

All project developers and verification bodies must refer to this document to ensure that the most current guidance is adhered to in project design and verification. Verification bodies shall refer to this document immediately prior to uploading any Verification Statement to assure all issues are properly addressed and incorporated into verification activities.

If you have any questions about the updates or clarifications in this document, please contact Policy at policy@climateactionreserve.org or (213) 891-1444 x3.

[1] See Section 4.3.4 of the Climate Action Reserve Program Manual for an explanation of the Reserve's policies on protocol errata and clarifications. "Errata" are issued to correct typographical errors. "Clarifications" are issued to ensure consistent interpretation and application of the protocol. For document management and program implementation purposes, both errata and clarifications are contained in this single document.

# Errata and Clarifications (arranged by protocol section)

# Section 7

## 1. Campaign Length (CLARIFICATION – January 3, 2017)

**Section:** 7.4 Reporting Period and Verification Cycle

**Context:** Section 7.4 states that reporting periods cannot exceed 12 months, and no more than 12 months of emission reductions can be verified at once, except during the project's first verification, which could include historical data. However, the protocol does not address circumstances when a campaign length exceeds a 12 month reporting period. While the protocol allows for sub-campaign verifications, it is preferable to allow for project developers to report on and verify full campaigns. Further, the provision for the first verification was only relevant for projects already underway at the time of protocol adoption and is no longer necessary.

**Clarification:** The language in Section 7.4 shall be amended as follows:

> A reporting period cannot exceed 12 months, and no more than 12 months of emission reductions can be verified at once, except when a single campaign exceeds 12 months, in which case the reporting period may be extended to match the length of the campaign.
>
> One site visit is required per verification or per year, whichever is less frequent.

CLIMATE ACTION RESERVE

Version 2.1 | June 21, 2016

# Nitric Acid Production

## Project Protocol

Climate Action Reserve
601 West 5th Street, Suite 650
Los Angeles, CA 90071
www.climateactionreserve.org

Released June 21, 2016

# Acknowledgements

## Lead Author

Kathryn Bickel Goldman

## Staff (in alphabetical order)

Max DuBuisson
Nancy Kong
Teresa Lang
Heather Raven
Rachel Tornek
Sarah Wescott

## Workgroup

| | |
|---|---|
| Kevin Townsend | Blue Source, LLC |
| Lei Guo | California Air Resources Board |
| William Flederbach | ClimeCo Corporation |
| James Winch | ClimeCo Corporation |
| Trine Kopperud | DNV |
| William Herz | The Fertilizer Institute |
| Marten von Velsen-Zerweck | N. Serve Environmental Services |
| David Hind | Orica Canada Inc /ANNA |
| Jim Schellhorn | Terra Industries Inc. |
| Mausami Desai | U.S. Environmental Protection Agency |
| Nathan Frank | U.S. Environmental Protection Agency |

# Table of Contents

# List of Tables



# List of Figures



# List of Equations

# Abbreviations and Acronyms

| | |
|---|---|
| AOC | Allowable operating conditions |
| AOR | Ammonia oxidation reactor or ammonia burner |
| BACT | Best available control technology |
| CAA | Clean Air Act |
| CDM | Clean Development Mechanism |
| $CH_4$ | Methane |
| $CO_2$ | Carbon dioxide |
| $CO_2e$ | Carbon dioxide equivalent |
| CRT | Climate Reserve Tonne |
| EPA | United States Environmental Protection Agency |
| FTIR | Fourier transform infrared spectroscopy |
| GHG | Greenhouse gas |
| $HNO_3$ | Nitric acid |
| MT | Metric ton (or tonne) |
| $N_2$ | Nitrogen |
| $N_2O$ | Nitrous oxide |
| NAP | Nitric acid plant |
| NDIR | Non-dispersive infrared sensor |
| $NH_3$ | Ammonia |
| NO | Nitric oxide |
| $NO_2$ | Nitrogen dioxide |
| $NO_X$ | Refers to $NO_2$ and NO |
| NSCR | Non-selective catalytic reduction |
| $O_2$ | Oxygen |
| PSD | Prevention of Significant Deterioration |
| RATA | Relative Accuracy Test Audit |
| SCR | Selective catalytic reduction |
| SSRs | Sources, sinks, and reservoirs |
| UNFCCC | United Nations Framework Convention on Climate Change |

# 1 Introduction

The Climate Action Reserve (Reserve) Nitric Acid Production Project Protocol provides guidance to account for, report, and verify greenhouse gas (GHG) emission reductions associated with the installation and use of a nitrous oxide ($N_2O$) emission control technology to reduce $N_2O$ emissions generated as a by-product of nitric acid production.

The Reserve is an offset registry serving the California cap-and-trade program and the voluntary carbon market. The Reserve encourages actions to reduce GHG emissions and works to ensure environmental benefit, integrity, and transparency in market-based solutions to address global climate change. It operates the largest accredited registry for the California compliance market and has played an integral role in the development and administration of the state's cap-and-trade program. For the voluntary market, the Reserve establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies, and issues and tracks the transaction of carbon credits (Climate Reserve Tonnes or CRTs) generated from such projects in a transparent, publicly-accessible system.[1] The Climate Action Reserve is a private 501(c)(3) non-profit organization based in Los Angeles, California.

Project developers that initiate $N_2O$ abatement projects use this document to register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive annual, independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve Verification Program Manual and Section 8 of this protocol.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with a $N_2O$ abatement project at a nitric acid plant.[2]

[1] The online registry may be accessed from the Reserve homepage at: www.climateactionreserve.org.
[2] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.

# 2 The GHG Reduction Project

## 2.1 Background

Nitric acid ($HNO_3$) is an inorganic compound used primarily to make synthetic commercial fertilizers. Virtually all of the nitric acid produced in the United States is produced by the catalytic oxidation of ammonia. In this industrial process, ammonia ($NH_3$) is oxidized using a primary catalyst in an ammonia oxidation reactor (AOR) to produce nitric oxide (NO). NO is oxidized with air in the AOR to form nitrogen dioxide ($NO_2$). Then, $NO_2$ is absorbed in water in an absorption tower to form nitric acid. $N_2O$ is formed as a by-product of the oxidation process in the AOR (during Stage 1 in Figure 2.1 below); it remains in the tail gas leaving the absorption tower and is eventually emitted with the stack gas to the atmosphere.[3] The reactions and stages of the nitric acid production process are illustrated in Figure 2.1.

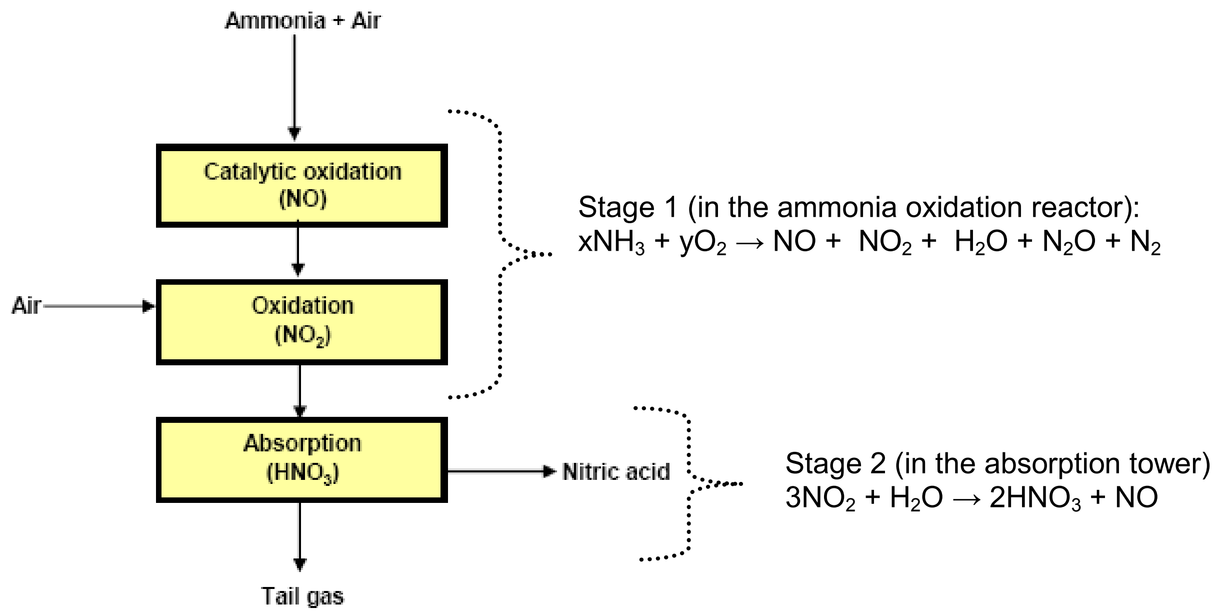
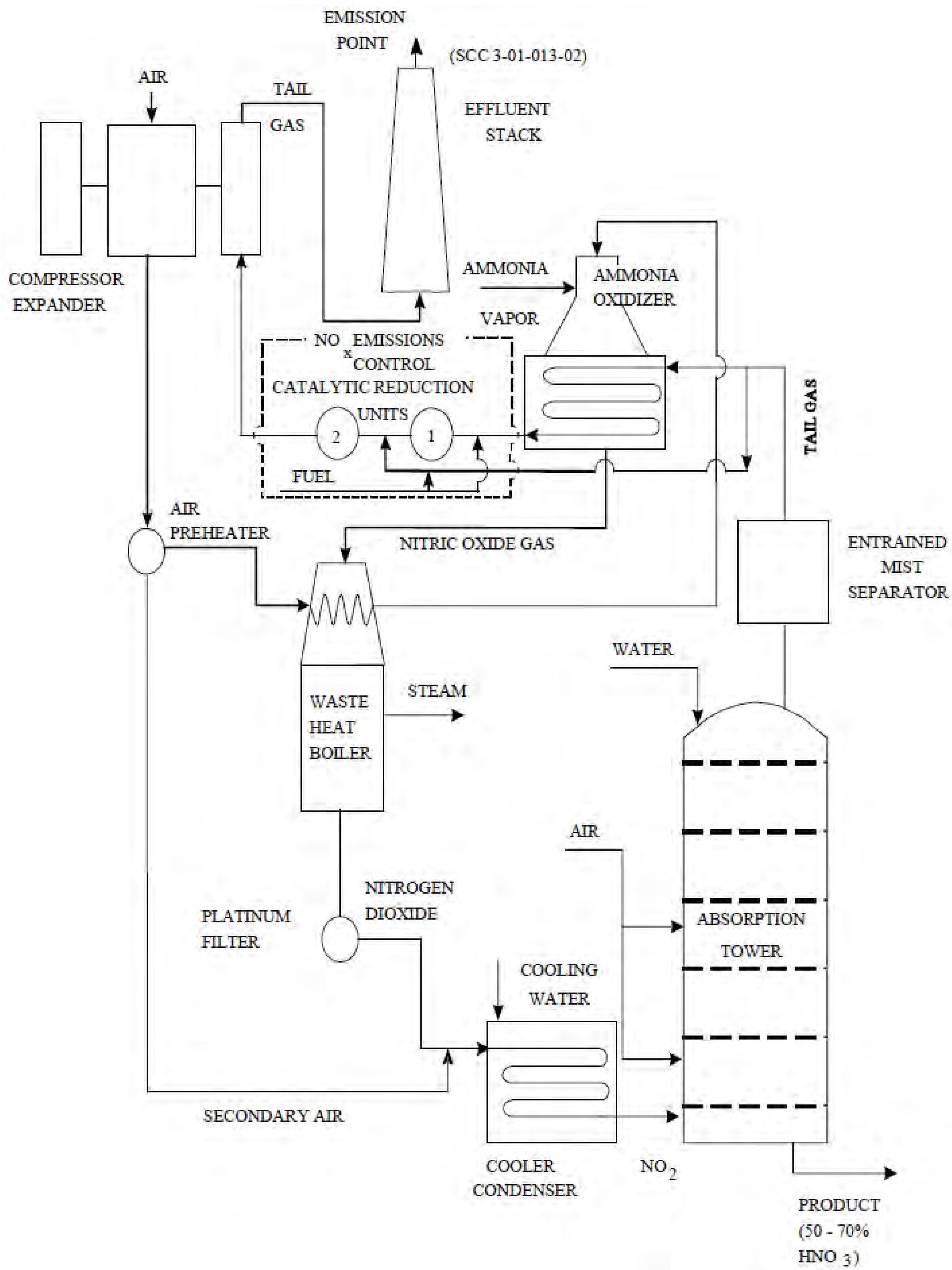



**Figure 2.1.** Reactions in the Nitric Acid Production Process

Nitric acid production facilities can operate one or more nitric acid plants (NAPs), where a plant encompasses a single process unit, i.e. the equipment and process used to produce nitric acid. Emissions from each plant at a facility are managed independently; process units at the same facility can operate under different conditions and have different emission controls in place. Figure 2.2 shows the physical set up and flows of inputs and gases in a generic NAP without any $N_2O$ emission controls in place.

[3] $NO_X$ is considered a criteria pollutant under the Clean Air Act and starting in the 1970s certain nitric acid plants were required to meet $NO_X$ emission limits by installing a $NO_X$ abatement technology.




Source: http://www.epa.gov/ttn/chief/ap42/ch08/final/c08s08.pdf and EPA-450/3-91-026: Alternative Control Techniques Document: Nitric and Adipic Acid Manufacturing Plants (1991).

**Figure 2.2.** Flow Diagram of a Typical Nitric Acid Plant Using Single-Pressure Process

There are two basic types of NAPs: single pressure and dual pressure. Single pressure designs, common in the United States, apply a single pressure throughout the reaction and absorption stages. Dual pressure designs use lower pressure in the AOR and higher pressure in the absorption tower. The amount of $N_2O$ formed during the nitric acid production process depends on combustion conditions (e.g. temperature and pressure), primary catalyst composition and age, and burner design.[4] Thus, the precise operating conditions of the NAP affect how much $N_2O$ is formed.

In response to the federal Clean Air Act (CAA), most NAPs currently operate with some form of NO and $NO_2$ (i.e. $NO_X$) emission control, usually selective catalytic reduction (SCR) technology and less often non-selective catalytic reduction (NSCR) technology. SCR can have a minor impact on $N_2O$ emissions (+/- <5% change), while NSCR destroys both $NO_X$ and $N_2O$. However, NSCR is generally not preferred in modern plants because of high energy costs and associated high gas temperatures.

Intentional approaches to $N_2O$ emissions abatement have been reviewed in the research literature[5] and highlighted by the Intergovernmental Panel on Climate Change (IPCC)[6], some of which have applicability in the United States. Potential measures for abating $N_2O$ emissions are outlined below in Table 2.1. Specific measures that may qualify as a project under this protocol are discussed below in Section 2.2.

**Table 2.1.** Potential $N_2O$ Abatement Measures

| Measure | Point of Application |
|---|---|
| Primary abatement | Prevents $N_2O$ formation in the ammonia burner by modification of (i.e. optimizing) the ammonia oxidation process and/or catalysts. |
| Secondary abatement | Removes $N_2O$ from the intermediate stream, i.e. from the gases between the AOR and the absorption tower. Usually this will mean intervening at the highest temperature, immediately downstream of the ammonia oxidation catalyst and catalytically reducing the $N_2O$ once it has been formed in the AOR. |
| Tertiary abatement | Treats the tail-gas leaving the absorption tower to destroy $N_2O$. $N_2O$ abatement can be placed upstream or downstream of the tail-gas expansion turbine. These abatement measures may include catalytic decomposition or NSCR. |

## 2.2 Project Definition

For the purposes of this protocol, a GHG reduction project is defined as the installation and operation of a $N_2O$ abatement technology at a single NAP that results in the reduction of $N_2O$ emissions that would otherwise have been vented to the atmosphere. Projects can only be implemented at existing, relocated, or upgraded NAPs provided historical $HNO_3$ production levels and allowable operating conditions can be established for such NAPs in accordance with Sections 5.1.1 and 5.2.1 of this protocol.

The protocol does not apply to projects at:

- NAPs that are restarted any time after December 2, 2007, after being out of operation for a period of 24 months or longer

[4] J. Perez-Ramirez, F. Kapteijn, K.Schoffel, J.A. Moulijn, Formation and control of $N_2O$ in nitric acid production N: Where do we stand today? Applied Catalysis B: Environmental 44 (2003) 117-151.
[5] Ibid.
[6] Intergovernmental Panel on Climate Change (IPCC) 2006 National GHG Inventory Guidelines. Volume 3 Industrial Processes.

- New NAPs constructed after December 2, 2009, with the exception of new NAPs for which a permit application for construction was submitted to the appropriate government authorities prior to December 2, 2009
- Secondary catalyst projects at existing NAPs where NSCR is currently operating
- Secondary catalyst projects at existing NAPs that used NSCR technology for $NO_X$ abatement at any point since December 2, 2007

If a tertiary catalyst project is installed at an existing NAP where NSCR has operated at any point since December 2, 2007, the NSCR must continue to operate during any period of time for which the project will claim CRTs (any $N_2O$ abatement that occurs as a result of the pre-existing NSCR is not eligible for emission reduction credits).

Since the project definition is tied to a single NAP, it is possible to register multiple projects at a nitric acid facility with multiple NAPs, each with its own start date, crediting period, registration and verification. However, a single project shall not consist of more than one $N_2O$ abatement technology. In other words, each project must consist of only one of the following $N_2O$ abatement technologies.

### 2.2.1 Secondary Catalyst Project

A secondary catalyst project is one that installs and operates a dedicated $N_2O$ abatement catalyst inside or immediately below the AOR.

### 2.2.2 Tertiary Catalyst Project

A tertiary catalyst project is one that installs and operates a dedicated $N_2O$ abatement catalyst in the tail gas leaving the absorption tower (or the tail gas leaving a pre-existing NSCR unit). The specific $N_2O$ abatement technology can either be catalytic decomposition or a NSCR $NO_X$ abatement technology used to destroy $N_2O$ along with $NO_X$.

It is possible to switch from one of the above project types to the other in cases where the initial installed technology negatively impacts the nitric acid production or fails to achieve the intended $N_2O$ abatement levels. However, the initial technology must be decommissioned and GHG reductions will be based on the quantification methodology for the final implemented technology. In this situation, the project developer shall revise the project based on the new abatement technology; the project developer does not need to resubmit the project and can continue the existing crediting period based on the installation of the previous abatement technology.

## 2.3 The Project Developer

The "project developer" is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers may be owners of nitric acid facilities, entities that specialize in project development, or $N_2O$ abatement technology suppliers. The project developer must have clear ownership of the project's GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership by signing the Reserve's Attestation of Title form.[7] The project developer must be the entity with liability for the emissions of the NAP (i.e. the entity named on the facility's Title V permit), unless the rights to the emissions reductions have been transferred to another entity.

[7] Attestation of Title form available at http://www.climateactionreserve.org/how/program/documents/.

# 3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the following eligibility rules in order to register with the Reserve.

| | | | |
|---|---|---|---|
| **Eligibility Rule I:** | Location | ⟶ | *U.S. and its territories* |
| **Eligibility Rule II:** | Project Start Date | ⟶ | *No more than six months prior to project submission* |
| **Eligibility Rule III:** | Project Crediting Period | ⟶ | *Ten-year crediting period, maximum of two crediting periods total* |
| **Eligibility Rule IV:** | Additionality | ⟶ | *Exceed legal requirements* |
| | | ⟶ | *Meet performance standard* |
| **Eligibility Rule V:** | Regulatory Compliance | ⟶ | *Compliance with all applicable laws* |

## 3.1 Location

Under this protocol, only projects located at nitric acid production facilities in the United States and its territories are eligible to register with the Reserve.[8]

## 3.2 Project Start Date

The project start date for a secondary catalyst project is defined as the date on which production first commences after the first installation of a secondary catalyst. The project start date must correspond to either the start of a campaign or commencement of nitric acid production after an outage. A campaign starts when production commences following the installation of a new charge of primary catalyst gauze or a new primary catalyst and ends when production ceases for the purpose of replacing or recharging the primary catalyst gauze.

The project start date for tertiary catalyst projects is defined as the date on which nitric acid production first commences after installation of the tertiary $N_2O$ abatement technology.

To be eligible, the project must be submitted for listing on the Reserve no more than six months after the project start date.[9] Projects may always be submitted for listing by the Reserve prior to their start date.

## 3.3 Project Crediting Period

The crediting period for projects under this protocol is ten years. If a project developer wishes to apply for eligibility under a second crediting period, they must do so within the final six months of the initial crediting period. However, the Reserve will cease to issue CRTs for GHG reductions if at any point in the future $N_2O$ abatement becomes legally required at the project site or the project otherwise fails the Legal Requirement Test (Section 3.4.1). Thus, the Reserve

[8] The Reserve anticipates that this protocol could be applied throughout North America and internationally. To expand its applicability, data and analysis supporting an appropriate performance standard for other countries would have to be conducted accordingly. Refer to Appendix A for information on the performance standard analysis supporting application of this protocol in the United States.

[9] Projects are considered submitted for listing when the project developer has fully completed and filed the appropriate submittal documents, which include the Project Submittal form (available on the Reserve's website) and a project diagram.

will issue CRTs for GHG reductions quantified and verified according to this protocol for a maximum of two ten-year crediting periods after the project start date, or until the project activity is required by law, whichever comes first. Section 3.4.1 defines the conditions under which a project is considered legally required, and Section 3.4.2 describes the requirements to qualify for a second crediting period.

## 3.4 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have otherwise occurred in the absence of a GHG market.

Projects must satisfy the following tests to be considered additional:

1. The Legal Requirement Test
2. The Performance Standard Test

### 3.4.1 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, rules, regulations, ordinances, court orders, governmental agency actions, enforcement actions, environmental mitigation agreements, permitting conditions, permits or other legally binding mandates requiring the abatement of $N_2O$ at the project site. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form[10] prior to the commencement of verification activities each time the project is verified (see Section 8). In addition, the project's Monitoring Plan (Section 6) must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test.

As of the Effective Date of this protocol, the Reserve could identify no existing federal, state or local regulations that obligate nitric acid plants to abate $N_2O$ emissions.[11] If an eligible project begins operation at a plant that later becomes subject to a regulation, ordinance or permitting condition that calls for the abatement of $N_2O$, emission reductions may be reported to the Reserve up until the date that $N_2O$ is legally required to be abated. If the nitric acid plant's $N_2O$ emissions are included under an emissions cap (e.g. under a state or federal cap-and-trade program), emission reductions may likewise be reported to the Reserve until the date that the emissions cap takes effect.

#### 3.4.1.1 U.S. EPA GHG Permitting Requirements under the Clean Air Act

Starting on January 2, 2011, the United States Environmental Protection Agency (U.S. EPA) has been phasing in[12] regulation of GHG emissions from major stationary sources under the Clean Air Act (CAA).[13]

[10] Form available at http://www.climateactionreserve.org/how/program/documents/.

[11] $NO_X$ emissions from nitric acid production facilities are regulated under the Clean Air Act and $NO_X$ Transport Rule, both of which provide guidelines for $NO_X$ emission controls. Regulations that limit $NO_X$ emissions from nitric acid production facilities do not require the installation of specific $NO_X$ control technologies; as a result, there is no direct or indirect regulatory requirement to control $N_2O$. While $N_2O$ is incidentally controlled by the use of NSCR, this is taken into account in the Performance Standard Test.

[12] All major sources already subject to PSD and/or Title V under the Clean Air Act for other pollutants will be subject to EPA's GHG permitting rules starting January 2, 2011. All sources *not* previously subject to the Clean Air Act will come under the GHG permitting rules on July 1, 2011, assuming they trigger the thresholds noted herein.

Under this rule, commonly referred to as the "Tailoring Rule," all existing stationary sources emitting more than 100,000 tons (approximately 90,719 MT) of $CO_2$e emissions per year will be required to obtain Title V operating permits for GHG emissions. Title V generally does not add new pollution control requirements. However, sources will need to address GHG-related information in their Title V permit applications going forward, which may include estimates and/or descriptions of GHG emissions and abatement technologies. As such, a voluntarily-installed GHG abatement technology may likely be reflected in any new Title V permit operating conditions. However, because the issuance of the new or revised Title V permit will not itself require or mandate the implementation of any *new* GHG abatement, the Reserve expects that such permits will not affect the eligibility status of currently registered projects.

The Tailoring Rule also requires Prevention of Significant Deterioration (PSD) permits that address GHG emissions for (1) new source construction with emissions of 100,000 tons $CO_2$e per year or more and (2) major facility modifications resulting in GHG emission increases of 75,000 tons (approximately 68,000 MT) of $CO_2$e per year or more.[14] An assessment of "best available control technology" (BACT) for GHGs will be required as part of the PSD permitting process, with the permitting authority ultimately mandating installation of a selected BACT. It is possible that future PSD permits may require installation of the same abatement technologies that are currently being voluntarily deployed as part of carbon offset projects. By legally mandating these technologies, PSD permit requirements may make them ineligible for carbon offsets because implementation of these projects would no longer be voluntary.

Nitric acid production facilities that undertake significant expansion and increase GHG emissions by 75,000 tons or more per year will be subject to the new PSD requirements beginning on January 2, 2011.[15] If a facility triggers the PSD requirements and an official BACT review results in the mandatory installation of a technology that reduces $N_2O$ emissions, this activity will not be eligible for carbon offsets. Projects at new facilities which would be subject to PSD requirements are already ineligible under this protocol.

Voluntarily-installed $N_2O$ abatement projects should continue to be eligible for carbon offsets for the remainder of a project's crediting period(s), even if that project activity is later added to a Title V permit. Verifiers will need to review Title V and PSD permits to ensure that projects are able to pass the Legal Requirement Test.

### 3.4.2 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a performance threshold, i.e. a standard of performance applicable to all $N_2O$ abatement projects, established on an *ex-ante* basis by this protocol.

The Performance Standard Test employed by this protocol is based on a national assessment of "common practice" for use of emission control technologies in NAPs to reduce $N_2O$

[13] U.S. EPA published the final rulemaking, "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule," in the Federal Register 3 June 2010. The rulemaking is commonly referred to as the "Tailoring Rule," and amended 40 CFR Parts 51, 52, 70, and 71. http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf#page=1

[14] "PSD and Title V Permitting Guidance for Greenhouse Gases," available at: http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf

[15] Most NAPs are already subject to the Clean Air Act, and as such, the Tailoring Rule will be effective January 2, 2011. NAPs not previously subject to the Clean Air Act will be subject to these requirements July 1, 2011.

emissions. The performance standard defines those technologies that the Reserve has determined will exceed common practice and therefore generate additional GHG reductions.[16]

By installing one of the following $N_2O$ abatement systems as defined in Section 2.2, the project passes the Performance Standard Test:

1. A secondary $N_2O$ abatement catalyst
2. A tertiary $N_2O$ abatement catalyst, including catalytic decomposition or NSCR

The Performance Standard Test is applied as of the project start date, and is evaluated at the project's initial verification. Once a project is registered, it does not need to be evaluated against future versions of the protocol or the Performance Standard Test for the duration of its first crediting period. However, if the project chooses to upgrade to a newer version of the protocol, it must meet the Performance Standard Test of that version of the protocol, applied as of the original project start date.

If a project developer wishes to apply for a second crediting period, the project must meet the eligibility requirements of the most current version of this protocol, including any updates to the Performance Standard Test, applied as of the project start date.

## 3.5 Regulatory Compliance

As a final eligibility requirement, project developers must attest that the project activities and project NAP are in material compliance with all applicable laws (e.g. air, water quality, safety, etc.) prior to verification activities commencing each time a project is verified. Project developers are required to disclose in writing to the verifier any and all instances of non-compliance of the project with any law. If a verifier finds that a project is in a state of recurrent non-compliance or non-compliance that is the result of negligence or intent, then CRTs will not be issued for GHG reductions that occurred during the period of non-compliance. Non-compliance solely due to administrative or reporting issues, or due to "acts of nature," will not affect CRT crediting. As part of this eligibility requirement, project developers must submit a signed Attestation of Regulatory Compliance form[17] prior to the commencement of verification activities each time the project is verified.

[16] A summary of the study to establish the Performance Standard Test is provided in Appendix A.
[17] Form available at http://www.climateactionreserve.org/how/program/documents/.

# 4 GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project developers in order to determine the total net change in GHG emissions caused by a NAP project.

As the protocol applies to two project types, the GHG Assessment Boundary specific to each project type is provided below.

## 4.1 Secondary Catalyst Project

Figure 4.1 provides a general illustration of the GHG Assessment Boundary for secondary catalyst projects, indicating which SSRs are included or excluded from the boundary.

Table 4.1 provides greater detail on each SSR and provides justification for all SSRs and gases that are excluded from the GHG Assessment Boundary.

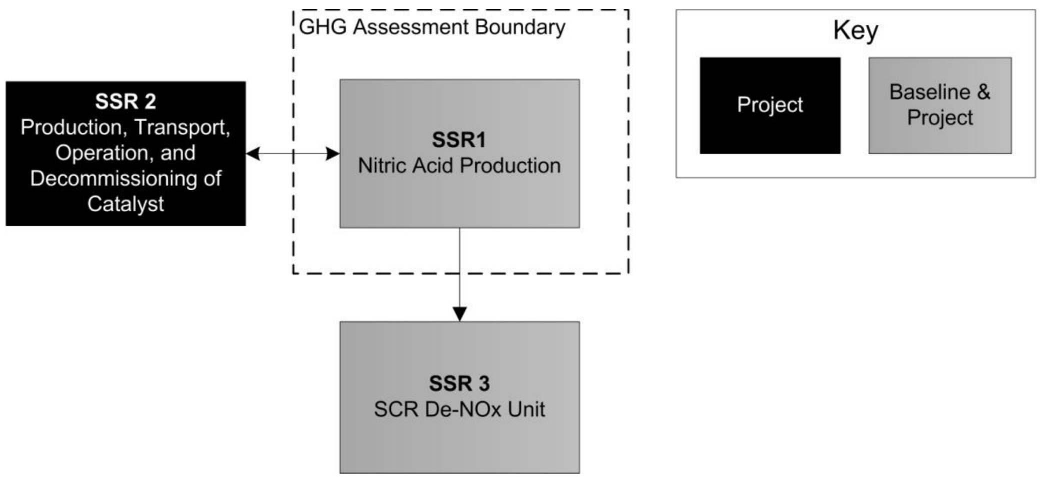



**Figure 4.1** Illustration of GHG Assessment Boundary for Secondary Catalyst Projects

**Table 4.1.** Summary of Identified Sources, Sinks, and Reservoirs for Secondary Catalyst Projects

| SSR | Source Description | Gas | Included (I) or Excluded (E) | Quantification Method | Baseline (B) or Project (P) | Justification/ Explanation |
|---|---|---|---|---|---|---|
| 1. Nitric Acid Production | Nitric acid process unit (burner inlet to stack) | $CO_2$ | E | N/A | B, P | Excluded, as project activity is unlikely to impact emissions relative to baseline activity |
| | | $CH_4$ | E | N/A | B, P | Excluded, as project activity is unlikely to impact emissions relative to baseline activity |
| | | $N_2O$ from reaction byproduct | I | Determination of emission factors based on continuously measured plant and production parameters | B, P | $N_2O$ from production reaction is a primary effect and a major emission source |
| 2. Secondary Catalyst | Emissions from production, transport, operation, and de-commissioning of the catalyst | $CO_2$, $CH_4$, $N_2O$ | E | N/A | P | Considered insignificant, upstream and downstream secondary GHG effects |
| 3. SCR De-$NO_X$ Unit | SCR de-$NO_X$ unit | $N_2O$ | E | N/A | B, P | $N_2O$ impact on existing SCR de-$NO_X$ unit is small and a secondary effect |

## 4.2 Tertiary Catalyst Projects

Figure 4.2 provides an illustration of the GHG Assessment Boundary for tertiary catalyst projects with existing SCR de-$NO_X$ units operating prior to the project start date, indicating which SSRs are included or excluded from the boundary.

Figure 4.3 provides an illustration of the GHG Assessment Boundary for tertiary catalyst projects without existing SCR de-$NO_X$ units operating prior to the project start date, indicating which SSRs are included or excluded from the boundary.

Table 4.2 provides greater detail on each SSR and provides justification for all SSRs and gases that are excluded from the GHG Assessment Boundary.

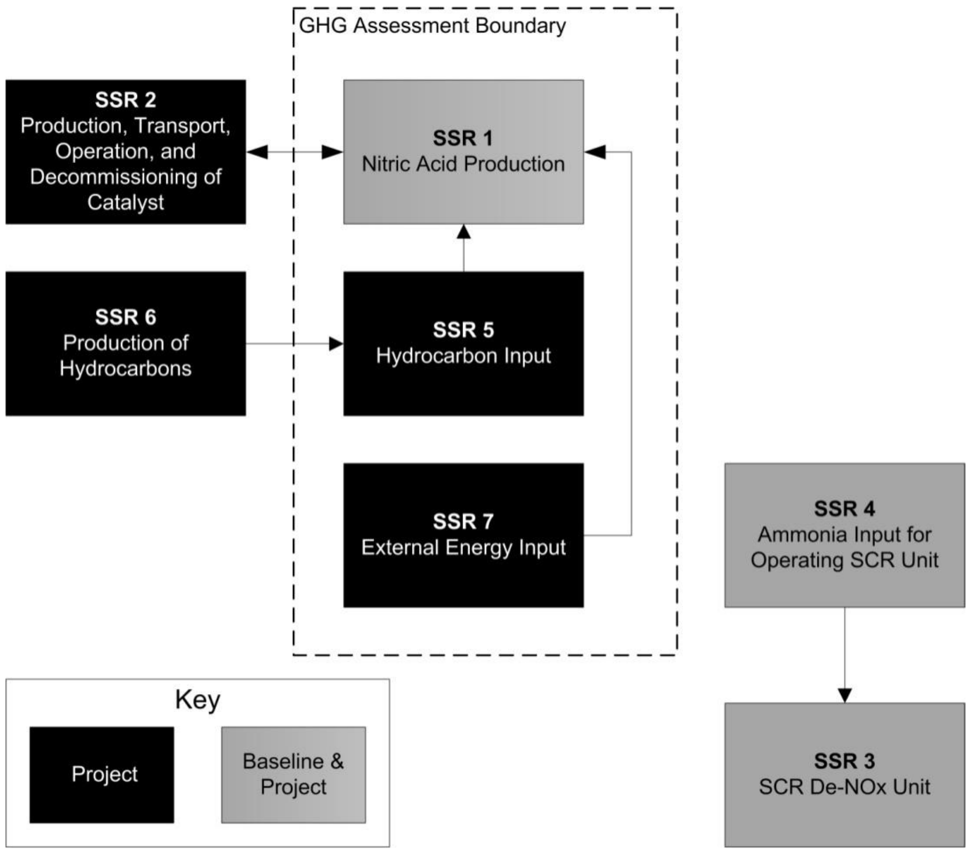



**Figure 4.2.** Illustration of GHG Assessment Boundary for Tertiary Projects with Existing SCR De-$NO_X$ Units Operating Prior to the Project Start Date

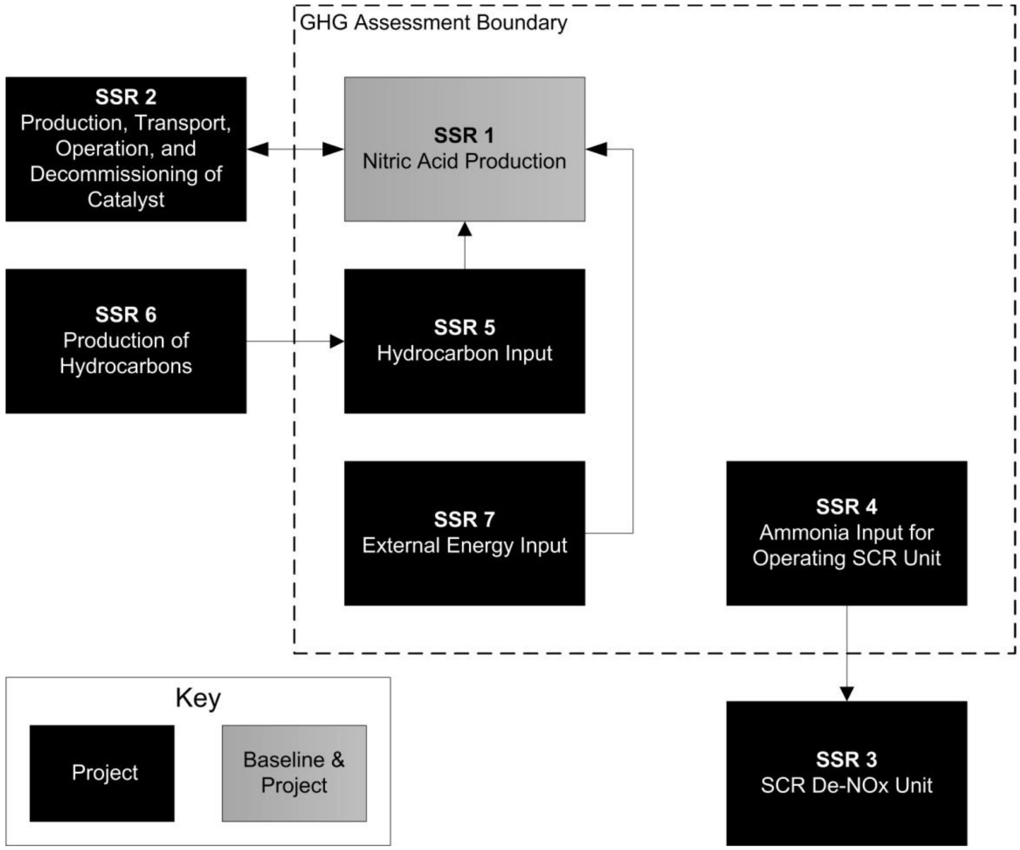



**Figure 4.3.** Illustration of GHG Assessment Boundary for Tertiary Projects without Existing SCR De-$NO_X$ Units Operating Prior to the Project Start Date

**Table 4.2.** Summary of Identified Sources, Sinks, and Reservoirs for Tertiary Catalyst Projects

| SSR | Source Description | Gas | Included (I) or Excluded (E) | Quantification Method | Baseline (B) or Project (P) | Justification/ Explanation |
|---|---|---|---|---|---|---|
| 1. Nitric Acid Production | Nitric acid process unit (burner inlet to stack) | $CO_2$ | E | N/A | B, P | Excluded, as project activity is unlikely to impact emissions relative to baseline activity |
| | | $CH_4$ | E | N/A | B, P | Excluded, as project activity is unlikely to impact emissions relative to baseline activity |
| | | $N_2O$ from reaction byproduct | I | $N_2O$ sampled before and after $N_2O$ destruction by tertiary catalyst | B, P | $N_2O$ from production reaction is a primary effect and a major emission source |
| 2. Tertiary Catalyst | Emissions from production, transport, operation, and de-commissioning of the catalyst | $CO_2$, $CH_4$, $N_2O$ | E | N/A | P | Considered insignificant, upstream and downstream secondary GHG effects |

| SSR | | Source Description | Gas | Included (I) or Excluded (E) | Quantification Method | Baseline (B) or Project (P) | Justification/ Explanation |
|---|---|---|---|---|---|---|---|
| 3. | SCR De-$NO_X$ Unit | $N_2O$ from SCR de-$NO_X$ unit | $N_2O$ | E | $N_2O$ concentrations sampled upstream of tertiary catalyst | B, P | $N_2O$ impact of existing SCR unit is small and a secondary effect. While not an included SSR, in practice the placement of emissions monitoring will determine whether $N_2O$ emission effects from an SCR de-$NO_X$ unit are actually measured. Such effects will be measured when the SCR de-$NO_X$ unit is located in between the $N_2O$ gas analyzers that measure baseline and project $N_2O$ gas concentrations. However, even if there is an effect, it is likely to be small and is considered negligible |
| 4. | Ammonia Used to Operate SCR De-$NO_X$ Unit | GHG emissions from production of ammonia used in tertiary abatement for $N_2O$ destruction | $CO_2$, $CH_4$, $N_2O$ | I (if ammonia is an input to the $N_2O$ destruction facility) | GHG emissions based on additional amounts of ammonia input used during the project | B, P | If SCR is in place prior to project implementation, GHG emissions related to ammonia production used for operating the SCR de-$NO_X$ unit will not be considered. However, if an SCR is installed as part of tertiary abatement, then GHG emissions from ammonia production will be considered as project emissions |

| SSR | | Source Description | Gas | Included (I) or Excluded (E) | Quantification Method | Baseline (B) or Project (P) | Justification/ Explanation |
|---|---|---|---|---|---|---|---|
| 5. | Hydrocarbon Input | Hydrocarbon used as reducing agent and/or reheating the tail gas | $CO_2$ and/or $CH_4$ | I | GHG emissions based on additional amounts of reducing agent or energy used during the project | P | If hydrocarbons are used as a reducing agent to enhance efficiency of the $N_2O$ catalyst, additional GHG emissions from the project activity will occur |
| 6. | Production of Hydrocarbons | Emissions related to the production of hydrocarbon | $CO_2$, $CH_4$, $N_2O$ | E | | P | GHG emissions related to the production of hydrocarbons used as reducing agent are insignificant |
| 7. | External Energy to Reheat Tail Gas | May be used to reheat the tail gas before entering the tertiary catalyst or NSCR | $CO_2$, $CH_4$, $N_2O$ | I | | P | If additional energy is used to reheat tail gas and that energy is not recovered and used within the system, additional GHG emissions from the project activity will occur |

# 5 Quantifying GHG Emission Reductions

The GHG reduction calculations provided in this protocol are derived from internationally accepted methodologies.[18] Project developers shall use the calculation method provided in this protocol to quantify baseline and project GHG emissions in order to determine emission reductions. Figures 5.1 and 5.2 display the relationships between the various equations used in this section.

GHG emission reductions must be quantified and verified on at least an annual basis. The length of time over which GHG emission reductions are quantified and verified is called the "reporting period." Reporting periods shall cover the same time period as a full campaign, unless a project developer chooses to report on a "sub-campaign" basis. See Section 7.4.1 for more information on sub-campaign reporting periods and verification.

## 5.1 Secondary Catalyst Projects

GHG emission reductions from a secondary catalyst project are quantified by comparing actual project emissions to baseline emissions at the NAP. Baseline emissions are an estimate of the GHG emissions from within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

**Equation 5.1.** Emission Reductions for Secondary Catalyst Projects

$$\boldsymbol{ER = BE - PE}$$

| *Where,* | | | <u>Units</u> |
|---|---|---|---|
| ER | = | Total emission reductions for the specific campaign | $tCO_2e$ |
| BE | = | Total baseline emissions for the specific campaign | $tCO_2e$ |
| PE | = | Total project emissions from the specific campaign | $tCO_2e$ |

A secondary catalyst project involves the installation of a $N_2O$ abatement catalyst directly beneath the primary catalyst within the AOR. Because these projects involve abatement within the AOR, the gas stream cannot be sampled between the primary and secondary catalysts. Thus, a baseline emission factor must be determined prior to installation of the secondary catalyst in order to estimate the project's baseline emissions, as will be discussed in Section 5.1.3. Similarly, project emissions are calculated for each campaign using a project emission factor which is derived based on data collected during that campaign (Section 5.1.4). This section begins with guidance regarding $HNO_{3,MAX}$ and the allowable operating conditions, which are relevant to both the baseline and project emissions calculations. Figure 5.1 illustrates the relationships between the various equations used in this section.

[18] The Reserve's GHG reduction calculation method for $N_2O$ abatement projects at nitric acid plants is adapted from the Kyoto Protocol's Clean Development Mechanism (AM0028 V.4.2 and AM0034 V.3.4). The methodology has been updated with the later adoption of ACM0019 V.1.0.

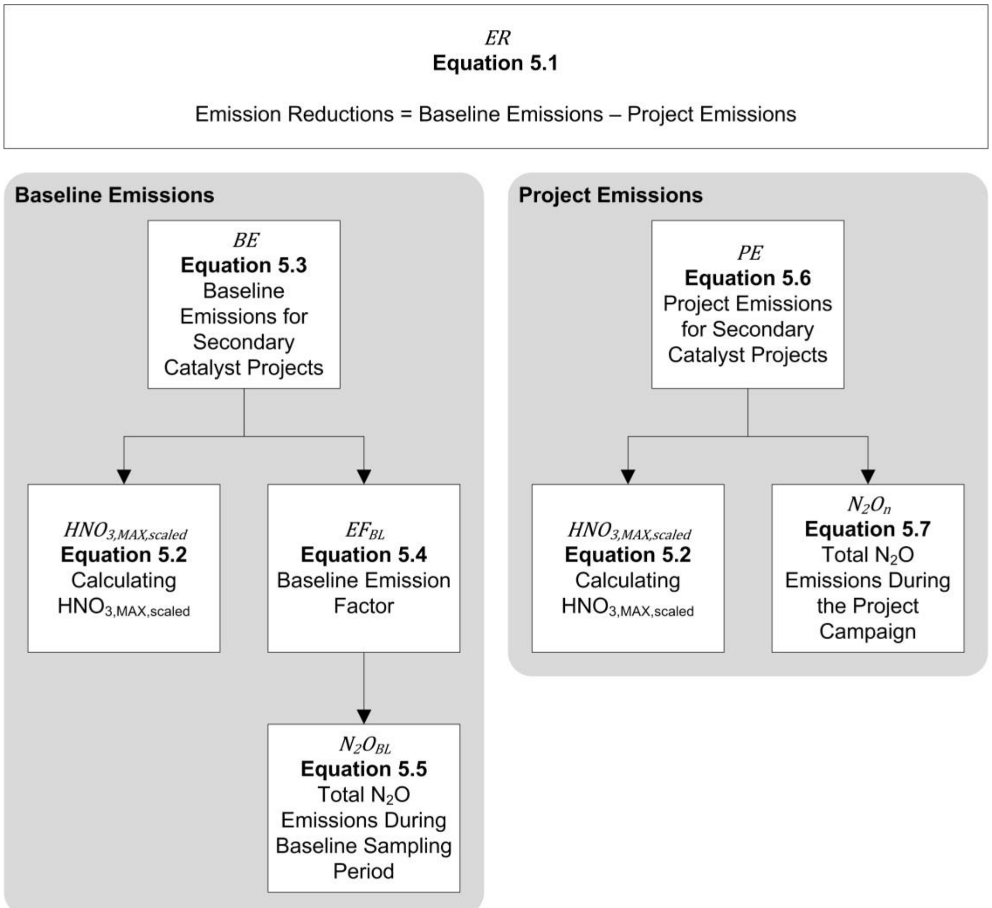



**Figure 5.1.** Organizational Chart of Equations for Secondary Catalyst Projects

### 5.1.1 Determination of $HNO_{3,MAX}$ and $HNO_{3,MAX,scaled}$

$HNO_{3,MAX}$ represents the historical maximum annual average total output of 100% concentration nitric acid. In order to use this factor for quantification of emission reductions, it must be scaled to the length of the campaign for which emission reductions are being calculated, which results in $HNO_{3,MAX,scaled}$.

In order to determine $HNO_{3,MAX}$, five consecutive years of historic data are used to calculate five values, each representing average $HNO_3$ production levels during a one year period at the process unit where the project is located. Average $HNO_3$ production can be calculated by averaging daily $HNO_3$ production data over a 12 month period, excluding days when the nitric acid plant was not operating.

If five years of historical data are not available to calculate five average $HNO_3$ production values, then five historical average $HNO_3$ production values may be calculated from five consecutive campaigns of $HNO_3$ production data, reported as an average hourly, daily, or per-campaign value. If one of the five consecutive campaigns is determined to be justifiably anomalous, the project may instead use five non-consecutive historical campaigns (i.e. exclude the anomalous campaign and add another campaign from the next available historical record). Under these circumstances, an explanation and justification for excluding the anomalous campaign must be included in the verification report for the project. Otherwise, if data from five consecutive campaigns are not available, then the nameplate capacity of the NAP shall be used to determine $HNO_{3,MAX}$.

**Equation 5.2.** Calculating $HNO_{3,MAX,scaled}$

$$HNO_{3_{MAX,scaled}} = HNO_{3_{MAX}} \times OD_n$$

| *Where,* | | | Units |
|---|---|---|---|
| $HNO_{3,MAX,scaled}$ | = | Historical maximum annual average total output of 100% concentration nitric acid, scaled to the length of the campaign for which emissions reductions are being calculated | $tHNO_3$ |
| $HNO_{3,MAX}$ | = | Historical maximum annual average total output of 100% concentration nitric acid (see below) | $tHNO_3$/day |
| $OD_n$ | = | Number of days of operation during the relevant campaign | days |

### 5.1.2 Allowable Operating Conditions

Prior to the installation of the secondary catalyst at the project NAP, the project developer must carry out a baseline sampling period in order to quantify the $N_2O$ emissions that would have occurred in the absence of the project activity. To ensure that $N_2O$ emissions during the baseline sampling period are representative of typical historical $N_2O$ emissions for the NAP and that operating conditions during the baseline sampling period are comparable to those during the project, the Reserve requires that allowable operating conditions (AOC) of the NAP be established for the following parameters, prior to beginning the baseline sampling period:

1. Oxidation temperature range
2. Oxidation pressure range
3. Maximum ammonia-to-air ratio input into the AOR (see Table 6.1 for secondary catalyst and Table 6.2 for tertiary catalyst)

The allowable ranges at the NAP shall be determined based on one of the following sources:

(a) The best available historical data for the operating range of temperature and pressure, and maximum ammonia-to-air ratio from the previous five campaigns.
(b) The best available historical data from less than five campaigns. This option is allowable only if limited historical data are available (e.g. an upgraded or relocated NAP that has not been operating for at least five campaigns).
(c) Specified range of temperature and pressure found in the operating manual[19] for the existing equipment, and maximum ammonia-to-air ratio as specified by the ammonia oxidation catalyst manufacturer or the operating manual for the NAP equipment if guidance from the ammonia oxidation catalyst manufacturer is not available. This option is only allowable if no historical data are available.

For NAPs that were upgraded or otherwise modified to increase production within 24 months prior to the project start date, AOC must be based on one of the options above using data collected after the commencement of production following completion of the upgrade, or the operating manuals for the upgraded plant. For NAPs that were upgraded or otherwise modified

[19] See definition of "operating manual" in Section 9, Glossary of Terms.

to increase production at any time during the project crediting period, AOC must be based on option (c) above.

For relocated NAPs, i.e. plants that were moved from one geographic location to another within 24 months prior to the project start date, AOC must be based on one of the options above using data collected after the plant was relocated.

If option (a) or (b) above is selected, the allowable range for temperature and pressure shall be determined through a statistical analysis of the historical data. All data that fall within the upper and lower 2.5 percentiles of the sample distribution are defined as potentially abnormal outliers and shall be eliminated. The allowable range of operating temperature and pressure is then assigned as the historical minimum and maximum operating conditions. Oxidation temperature and oxidation pressure data that are generated before ammonia begins flowing to the reactor shall be excluded prior to eliminating the upper and lower 2.5% of the observations.

Once the allowable ranges are determined, it must be demonstrated that these ranges are within the specifications of the facility by comparison with operating manuals for the existing equipment and ammonia catalyst specifications. If the AOC are not consistent with the above documentation, then additional campaigns should be undertaken until the allowable ranges can meet this criterion. However, if abnormal ammonia-to-air ratio levels are recorded during the historic campaigns used to establish the AOC for the project, and documentation or justification is available to support the assertion that the recorded levels are erroneous, the verification body may use professional judgment to review the documentation and make a determination as to whether the abnormal ammonia-to-air ratio levels should be eliminated from the historical dataset.

### 5.1.3 Quantifying Baseline Emissions

Baseline emissions represent the GHG emissions within the GHG Assessment Boundary that would have occurred in the absence of the GHG reduction project.

**Equation 5.3.** Baseline Emissions for Secondary Catalyst Projects

$$\boldsymbol{BE = \left[\left(EF_{BL} \times HNO_{3_{RP,scaled}}\right) + \left(EF_{New} \times HNO_{3_{New}}\right)\right] \times 310}$$

*Where,* Units

| | | | |
|---|---|---|---|
| BE | = | Total baseline emissions for the specific campaign | $tCO_2e$ |
| $EF_{BL}$ | = | Baseline emission factor (as calculated in Equation 5.4) | $tN_2O/tHNO_3$ |
| $HNO_{3,RP,scaled}$ | = | Quantity of nitric acid production used to quantify emission reductions, not exceeding $HNO_{3,MAX,scaled}$. Equal to the lesser of $HNO_{3,MAX,scaled}$ (calculated in Equation 5.2) or $HNO_{3,RP}$ (plant output of $HNO_3$ during the reporting period, further described in Table 6.1) | $tHNO_3$ |
| $EF_{New}$ | = | Default baseline emission factor for new production in excess of $HNO_{3,MAX,scaled}$ (Table B.1) | $tN_2O/tHNO_3$ |
| $HNO_{3,New}$ | = | Quantity of nitric acid production by which $HNO_{3,RP}$ (Table 6.1plant output of $HNO_3$ during the reporting period) exceeds $HNO_{3,MAX,scaled}$ (calculated in Equation 5.2). If $HNO_{3,RP} < HNO_{3,MAX,scaled}$, this value will be zero. | $tHNO_3$ |

| | | | |
|---|---|---|---|
| 310 | = | Global warming potential for $N_2O$ | $tCO_2e/tN_2O$ |

#### 5.1.3.1 Baseline Sampling Period

A baseline sampling period must be conducted prior to the installation of the secondary catalyst at the project NAP. The baseline sampling period must encompass, at a minimum, the first ten weeks of a campaign, beginning with the resumption of nitric acid production following the installation of a new primary catalyst or new charge of primary catalyst gauze in the AOR.

A continuous emission monitoring system (CEMS) installed using the guidance in Section 6 shall be used to provide separate readings for $N_2O$ concentration and gas flow volume in the stack gas during the baseline sampling period. As shown in Equation 5.5 the total $N_2O$ produced during the baseline sampling period ($N_2O_{BL}$) is calculated from the sample data by multiplying the average $N_2O$ concentration in the stack gas, the average hourly flow rate of stack gas, and total operating hours during the baseline sampling period.

Prior to calculating $N_2O_{BL}$, the data collected during the baseline sampling period shall be adjusted through the following steps:

**Step 1: Elimination of data beyond the campaign production volume cap**

To account for variations in the volume of nitric acid produced during individual campaigns and its influence on $N_2O$ emissions, a cap is applied on the volume of production during the baseline sampling period. Campaign production volume is defined as the total metric tons of nitric acid at 100% concentration produced with one set of primary catalyst gauzes (i.e. $HNO_3$ produced in between new catalyst installations or new charges of catalyst gauze). The cap ($CPV_{cap}$) is defined as the average campaign production volume (in metric tons $HNO_3$) for the campaigns used to define the allowable operating conditions. If one of the campaigns used to define allowable operating conditions is determined to be justifiably anomalous, the project may instead use five non-consecutive historical campaigns (i.e. exclude the anomalous campaign and add another campaign from the next available historical record). If the project developer excludes an anomalous campaign, the verification body must use professional judgment to review the justification and relevant data to make a determination as to whether the anomalous campaign is in fact justifiably anomalous and should be excluded from the $CPV_{cap}$ calculations. If the amount of $HNO_3$ produced during the baseline sampling period exceeds $CPV_{cap}$, then $N_2O$ values, $HNO_3$ production, and operating hours measured beyond $CPV_{cap}$ (i.e. beyond the point in time when $HNO_3$ production met the production limit as defined by $CPV_{cap}$) are to be eliminated from the calculation of the baseline emission factor $EF_{BL}$ in Equation 5.3 and $N_2O_{BL}$ in Equation 5.4. If the amount of $HNO_3$ produced during the baseline sampling period does not exceed $CPV_{cap}$, all $N_2O$ values measured, operating hours recorded, and total $HNO_3$ produced during the baseline sampling period shall be used for the calculation of $EF_{BL}$ and $N_2O_{BL}$ (subject to any elimination of data as required below).

**Step 2: Elimination of data outside of allowable operating conditions**

If the NAP operates outside of allowable temperature and pressure ranges or above the maximum ammonia-to-air ratio during the baseline sampling period, the following adjustments must be made prior to calculation of baseline emissions and the baseline emission factor:

1. Gas concentration and hourly flow rate recorded when the NAP was operating outside of allowable ranges shall be eliminated
2. The amount of time for which the NAP operated outside of allowable ranges shall be subtracted from the total operating hours
3. The amount of nitric acid produced during time periods during which the NAP operated outside of allowable ranges shall be subtracted from the total amount produced during the baseline sampling period

If the NAP operates outside of the established allowable range for more than 50% of the duration of the baseline sampling period, the baseline $N_2O$ emissions data are considered invalid and sampling must be repeated.

**Step 3: Elimination of outliers**

Measurement results can be distorted before and after periods of downtime or malfunction of the monitoring system. To eliminate such extremes and to ensure a conservative approach, the following statistical valuation is to be applied to the data series of $N_2O$ concentration and gas volume flow (not operating hours).

(a) Calculate the sample means (x)
(b) Calculate the sample standard deviations
(c) Calculate the 95% confidence intervals (equal to 1.96 times the standard deviations)
(d) Eliminate all data that lie outside the 95% confidence intervals (for gas flow and concentration only; do not eliminate operating hours in this step)
(e) Calculate the new sample means from the remaining values (flow of stack gas, $F_{BL}$, and $N_2O$ concentration of stack gas, $N_2O_{conc,BL}$)

To further ensure that operating conditions during the baseline sampling period are representative of AOC, the Reserve requires the mean values for oxidation temperature, oxidation pressure, and ammonia-to-air ratio are within the corresponding ranges defined for the AOC. If the mean values for any of these parameters fall outside of the allowable ranges (or above the maximum for the ammonia-to-air ratio), then the baseline sampling period is invalid and must be repeated.

#### 5.1.3.2 Baseline Emission Factor

As stated above, because the gas stream cannot be sampled between the primary and secondary catalysts, a baseline emission factor must be determined prior to installation of the secondary catalyst in order to estimate baseline emissions. As shown in Equation 5.4, the baseline emission factor represents the average $N_2O$ emissions per metric ton of nitric acid over the baseline sampling period ($tN_2O/tHNO_3$.). The baseline emission factor shall remain static for the life of the project.

**Equation 5.4.** Baseline Emission Factor

$$EF_{BL} = \frac{N_2O_{BL}}{HNO_{3_{BL}}}$$

*Where,* Units

| | | | |
|---|---|---|---|
| $EF_{BL}$ | = | Baseline $N_2O$ emissions factor | $tN_2O/tHNO_3$ |
| $N_2O_{BL}$ | = | Total $N_2O$ emissions during the baseline sampling period (Equation 5.5) | $tN_2O$ |
| $HNO_{3,\ BL}$ | = | Total nitric acid production during the baseline sampling period | $tHNO_3$ |

The term $N_2O_{BL}$ represents the total $N_2O$ emissions that were produced during the baseline sampling period, and is calculated using Equation 5.5.

Using the data for volume flow rate, $N_2O$ concentration, and operating hours gathered during the baseline sampling period and adjusted per Section 5.1.3.1, the project developer shall calculate the total $N_2O$ emissions during the baseline sampling period according to Equation 5.5.

**Equation 5.5.** Total $N_2O$ Emissions during the Baseline Sampling Period

$$N_2O_{BL} = F_{BL} \times N_2O_{conc,BL} \times OH_{BL} \times 10^{-9}$$

*Where,* Units

| | | | |
|---|---|---|---|
| $N_2O_{BL}$ | = | Total $N_2O$ emissions during the baseline sampling period | $tN_2O$ |
| $F_{BL}$ | = | Mean gas volume flow rate at the stack during the baseline sampling period | $m^3$/hour |
| $N_2O_{conc,BL}$ | = | Mean $N_2O$ concentration in the stack gas during the baseline sampling period | $mgN_2O/m^3$ |
| $OH_{BL}$ | = | Total operating hours of the baseline sampling period | hours |
| $10^{-9}$ | = | Unit conversion | t/mg |

### 5.1.4 Quantifying Project Emissions

Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary as a result of the project activity. Project emissions are calculated on an *ex-post* basis from measurements taken after the secondary catalyst is installed.

If the NAP operates outside of the established range for AOC for more than 50% of the duration of the campaign, the $N_2O$ emissions data are considered invalid and no emission reductions can be claimed by the project for that campaign.

To further ensure that operating conditions during the project are representative of AOC, the Reserve requires the mean values for oxidation temperature, oxidation pressure, and ammonia-to-air ratio are within the corresponding ranges defined for the AOC. If the mean values for any of these parameters fall outside of the allowable ranges (or above the maximum for the ammonia-to-air ratio), no emission reductions can be claimed by the project for that campaign.

**Equation 5.6.** Project Emissions for Secondary Catalyst Projects

$$PE = N_2O_n \times 310$$

*Where,*

| | | | Units |
|---|---|---|---|
| PE | = | Total project emissions for the specific campaign | $tCO_2e$ |
| $N_2O_n$ | = | Total $N_2O$ emissions of a specific project campaign (as calculated in Equation 5.7) | $tN_2O$ |
| 310 | = | Global warming potential for $N_2O$ | $tCO_2e/tN_2O$ |

### 5.1.4.1 Project Campaign Emission Factor

$N_2O$ concentration and gas volume flow in the stack of the NAP, as well as the temperature and pressure, ammonia gas flow, and ammonia-to-air ratio, will be measured continuously for the duration of the project activity, and summarized over each campaign during the project lifetime. While in most cases data are summarized over each consecutive campaign length during the crediting period, if the baseline sampling period lasts for less than a full campaign and the secondary catalyst is installed in the middle of a campaign length then, for that period only, project emissions are calculated based on the time between catalyst installation and the end of the campaign. The guidance below is specific to a full campaign length but should be adapted for the exceptional case above as needed.

The same CEMS used during the baseline sampling period shall be used to monitor project emissions. The same statistical evaluation that was applied to the baseline data series shall be applied to the project data series of $N_2O$ concentration and gas volume flow only (no elimination of data for operating hours or nitric acid production). For each campaign length:

(a) Calculate the sample mean (x)
(b) Calculate the sample standard deviation(s)
(c) Calculate the 95% confidence interval (equal to 1.96 times the standard deviation)
(d) Eliminate all data that lie outside the 95% confidence interval
(e) Calculate the new sample mean from the remaining values

After the above steps, campaign-specific $N_2O$ emissions are calculated using Equation 5.7. The value of $OH_n$ represents a total for the campaign, and no data are to be eliminated from this dataset for the calculation of Equation 5.7. Furthermore, no project data are eliminated that fall outside the AOC.

**Equation 5.7.** Total $N_2O$ Emissions during the Project Campaign

$$N_2O_n = F_n \times N_2O_{conc,n} \times OH_n \times 10^{-9}$$

*Where,* Units

| | | | |
|---|---|---|---|
| $N_2O_n$ | = | Total $N_2O$ emissions during the $n^{th}$ project campaign | $tN_2O$ |
| $F_n$ | = | Mean stack gas volume flow during the $n^{th}$ project campaign | $m^3$/ hour |
| $N_2O_{conc,n}$ | = | Mean concentration of $N_2O$ in the stack gas during the $n^{th}$ project campaign | $mgN_2O/ m^3$ |
| $OH_n$ | = | Total number of hours of operation during the $n^{th}$ project campaign | hours |
| $10^{-9}$ | = | Unit conversion | t/mg |

## 5.2 Tertiary Catalyst Project

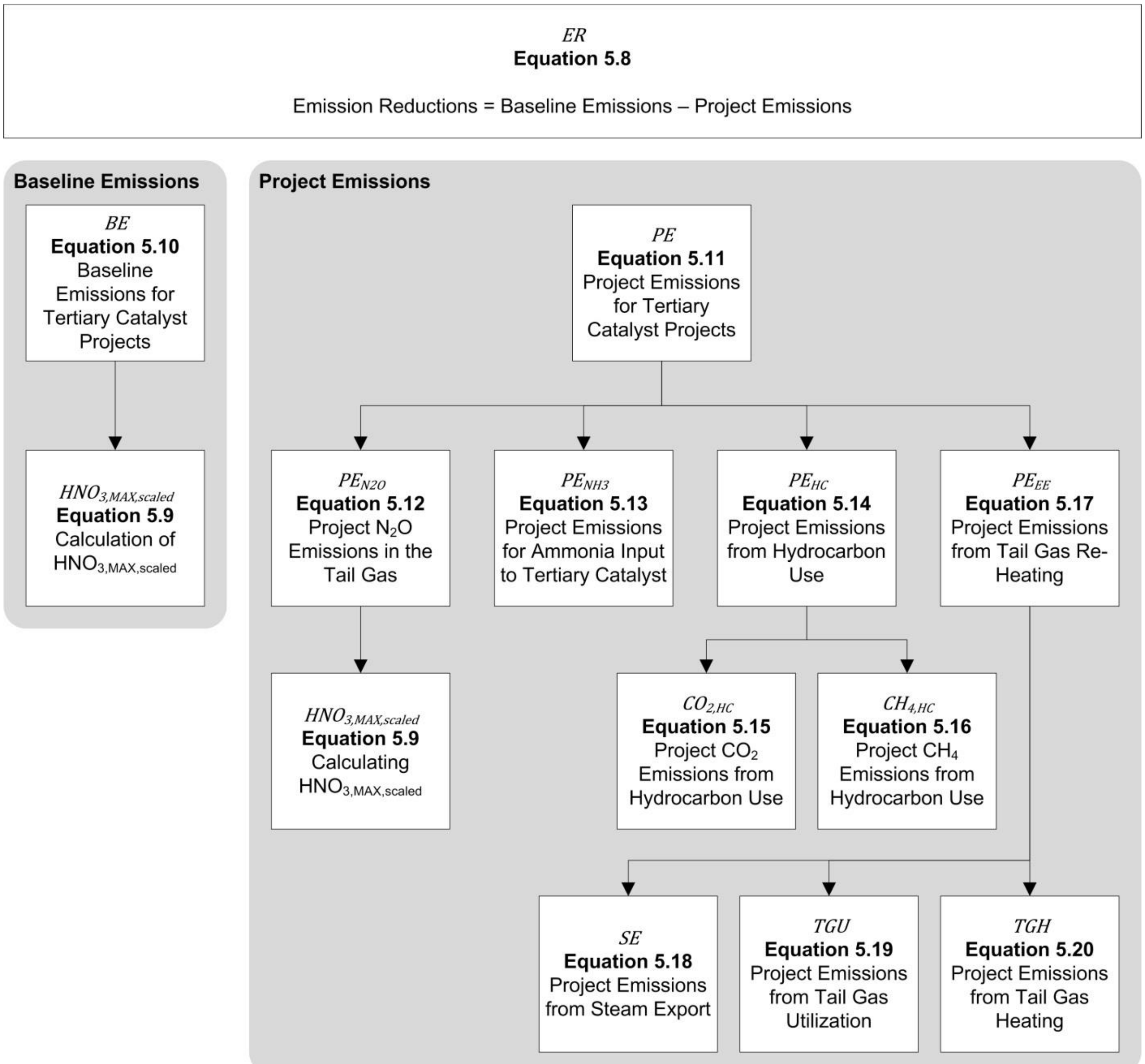



**Figure 5.2.** Organizational Chart of Equations for Tertiary Catalyst Projects

Equation 5.8 provides the quantification approach that shall be used for calculating the emission reductions from tertiary catalyst $N_2O$ abatement projects.

**Equation 5.8.** Emission Reductions for Tertiary Catalyst Projects

$$ER = BE - PE$$

| *Where,* | | | Units |
|---|---|---|---|
| ER | = | Emission reductions during the reporting period | $tCO_2e$ |
| BE | = | Baseline emissions during the reporting period (as calculated in Equation 5.10) | $tCO_2e$ |
| PE | = | Project emissions during the reporting period (as calculated in Equation 5.11) | $tCO_2e$ |

### 5.2.1 Determination of $HNO_{3,MAX}$ and $HNO_{3,MAX,scaled}$

$HNO_{3,MAX}$ represents the historical maximum annual average total output of 100% concentration nitric acid. In order to use this factor for quantification of emission reductions, it must be scaled to the length of the campaign for which emission reductions are being calculated, which results in a second factor: $HNO_{3,MAX,scaled}$. To determine $HNO_{3,MAX}$, five consecutive years of historic data are used to calculate five values, each representing average $HNO_3$ production levels during a one year period at the process unit where the project is located. Average $HNO_3$ production can be calculated by averaging daily $HNO_3$ production data over a 12 month period, excluding days when the nitric acid plant was not operating.

If five years of historical data are not available to calculate five average $HNO_3$ production values, then five historical average $HNO_3$ production values may be calculated from five consecutive campaigns of $HNO_3$ production data, reported as an average hourly, daily or per-campaign value. If one of the five consecutive campaigns is determined to be justifiably anomalous, the project may instead use five non-consecutive historical campaigns (i.e. exclude the anomalous campaign and add another campaign from the next available historical record). Under these circumstances, an explanation and justification for excluding the anomalous campaign must be included in the verification report for the project. Otherwise, if data from five consecutive campaigns are not available, then use the nameplate capacity of the NAP to determine $HNO_{3,MAX}$.

**Equation 5.9.** Calculation of $HNO_{3,MAX,scaled}$

$$HNO_{3_{MAX,scaled}} = HNO_{3_{MAX}} \times OD_n$$

| *Where,* | | | Units |
|---|---|---|---|
| $HNO_{3,MAX,scaled}$ | = | Historical maximum annual average total output of 100% concentration nitric acid, scaled to the length of the campaign for which emission reductions are being calculated | $tHNO_3$ |
| $HNO_{3,MAX}$ | = | Historical maximum annual average total output of 100% concentration nitric acid (see below) | $tHNO_3$/day |
| $OD_n$ | = | Number of days of operation during the project campaign | days |

### 5.2.2 Allowable Operating Conditions

As in secondary catalyst projects, it is necessary with tertiary catalyst projects to determine the allowable operating conditions (AOC) for the NAP to ensure operating conditions during the project are consistent with historical operating conditions. Follow the steps in Section 5.1.2 to determine the allowable range of operating conditions for the NAP where the tertiary catalyst project is being implemented.

If actual average daily operating conditions for pressure, temperature, and ammonia-to-air ratio are outside of the allowable range anytime during interval *i*, baseline emissions during interval *i* are calculated from the lowest of the following options:

(a) $N_2O$ emissions calculated using the conservative IPCC default emission factor corresponding to the calendar year of the reporting period (see Table B.1) multiplied by $HNO_{3,i}$ ($HNO_3$ production in interval *i*); or
(b) $N_2O$ emissions calculated over the interval *i*, where $BE_i = F_i \times N_2O_{conc,in,i} \times OH_I \times 310$ (see Equation 5.9 for definition of variables).

If the NAP operates outside of the established range for AOC for more than 50% of the reporting period, the $N_2O$ emissions data are considered invalid and no emission reductions can be claimed by the project for that reporting period.

To further ensure that operating conditions during the project are representative of AOC, the Reserve requires the mean values for oxidation temperature, oxidation pressure, and ammonia-to-air ratio are within the corresponding ranges defined for the AOC. If the mean values for any of these parameters fall outside of the allowable ranges or above the maximum ammonia-to-air ratio, no emission reductions can be claimed by the project for that campaign.

### 5.2.3 Quantifying Baseline Emissions

Baseline emissions represent the GHG emissions within the GHG Assessment Boundary that would have occurred in the absence of the GHG reduction project (Equation 5.8). Baseline GHG emissions are based on the quantity of $N_2O$ in the tail gas before it enters the tertiary project abatement technology. Projects that involve the installation of a tertiary catalyst at a NAP with a pre-existing NSCR system must sample the tail gas after it leaves the pre-existing NSCR unit, prior to entering the tertiary project abatement technology. GHG emissions from the use of a reducing agent or energy to reheat tail gas and from production of input ammonia, for the purposes of operating the tertiary catalyst, are considered to be zero in the baseline.

The baseline is calculated from data collected during project operations by monitoring $N_2O$ concentrations before the tail gas enters the tertiary catalyst or NSCR.

**Equation 5.10.** Baseline Emissions for Tertiary Catalyst Projects

$$BE = \sum_{i}^{n} \left( F_i \times N_2O_{conc,in,i} \times OH_i \right) \times 310$$

When $HNO_{3,RP} \leq HNO_{3,MAX,scaled}$
Otherwise,

$$BE = \left[ \left[ \sum_{i}^{n} \left( F_i \times N_2O_{conc,in,i} \times OH_i \right) \times 310 \right] \times \frac{HNO_{3,MAX,scaled}}{HNO_{3,RP}} \right] + \left[ EF_{New} \times 310 \times \left( 1 - \frac{HNO_{3,MAX,scaled}}{HNO_{3,RP}} \right) \right]$$

| *Where,* | | | Units |
|---|---|---|---|
| BE | = | Baseline emissions during the reporting period | $tCO_2e$ |
| $F_i$ | = | Volume flow rate in the destruction facility[20] during interval *i*[21] | $m^3$/hour |
| $N_2O_{conc,in,i}$ | = | $N_2O$ concentration at the inlet to the destruction facility during interval *i* | $tN_2O/m^3$ |
| $OH_i$ | = | Operating hours in interval *i* | hours |
| *i* | = | Interval number | |
| n | = | Number of intervals in the reporting period | |
| 310 | = | Global warming potential of $N_2O$ | $tCO_2e/tN_2O$ |
| $HNO_{3,RP}$ | = | Amount of nitric acid produced during the reporting period | $tHNO_3$ |
| $HNO_{3,MAX,scaled}$ | = | Maximum annual average nitric acid production (see below) during an amount of time equivalent to the reporting period | $tHNO_3$ |
| $EF_{New}$ | = | Default baseline emission factor for new production in excess of $HNO_{3,MAX,scaled}$ (Table B.1) | $tN_2O/tHNO_3$ |

For any intervals where the NAP operates outside of AOC and the IPCC default is to be used:

$$BE_i = HNO_{3_i} \times EF_{IPCC} \times 310$$

| *Where,* | | | Units |
|---|---|---|---|
| BE | = | Baseline emissions during interval *i* when the NAP is operating outside of AOC | $tCO_2e$ |
| $HNO_{3,i}$ | = | Total nitric acid production in interval *i* | $tHNO_3$ |
| $EF_{IPCC}$ | = | IPCC default emission factor corresponding to the calendar year of the reporting period (Table B.1) | $tN_2O/tHNO_3$ |
| 310 | = | Global warming potential of $N_2O$ | $tCO_2e/tN_2O$ |

[20] Destruction facility refers to the equipment housing the tertiary catalyst or other $N_2O$ abatement technology if applicable (i.e. NSCR).
[21] It is only necessary to measure volume flow rate in one location, either upstream or downstream of the destruction facility because the system is closed and thus flow rate should be constant.

### 5.2.4 Quantifying Project Emissions

Project emissions are comprised of three sources: $N_2O$ emissions in the tail gas downstream of the tertiary catalyst facility, GHG emissions from the use of ammonia as input to the tertiary catalyst facility, and use of hydrocarbons as a reducing agent or to reheat tail gas.

**Equation 5.11.** Project Emissions for Tertiary Catalyst Projects

$$PE = PE_{N_2O} + PE_{NH_3} + PE_{HC} + PE_{EE}$$

*Where,*

| | | | Units |
|---|---|---|---|
| PE | = | Project emissions during the reporting period | $tCO_2e$ |
| $PE_{N2O}$ | = | GHG emissions from $N_2O$ in the tail gas during the reporting period (as calculated in Equation 5.12) | $tCO_2e$ |
| $PE_{NH3}$ | = | GHG emissions from the ammonia input used to operate the tertiary catalyst facility during the reporting period (as calculated in Equation 5.13) | $tCO_2e$ |
| $PE_{HC}$ | = | GHG emissions from the use of hydrocarbons as a reducing agent or to reheat tail gas during the reporting period (as calculated in Equation 5.14) | $tCO_2e$ |
| $PE_{EE}$ | = | GHG emissions from external energy used to reheat tail gas during the reporting period (as calculated in Equation 5.17) | $tCO_2e$ |

#### 5.2.4.1 Calculating Project $N_2O$ Emissions in the Tail Gas

Tertiary catalyst $N_2O$ abatement is not 100% efficient; therefore, $N_2O$ emissions that are not destroyed by the catalyst are measured and included as project emissions.

**Equation 5.12.** Project $N_2O$ Emissions in the Tail Gas

$$PE_{N_2O} = \sum_{i}^{n} \left(F_i \times N_2O_{conc,out,i} \times OH_i\right) \times 310$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{N2O}$ | = | $N_2O$ emissions from tail gas during the reporting period | $tCO_2e$ |
| $F_i$ | = | Volume flow rate in the destruction facility during interval *i*[22] | $m^3$/hour |
| $N_2O_{conc,out,i}$ | = | $N_2O$ concentration at the outlet to the tertiary catalyst during interval *i* | $tN_2O/m^3$ |
| $OH_i$ | = | Operating hours in interval *i* | hours |
| *i* | = | Interval number | |
| n | = | Number of intervals in the reporting period | |
| 310 | = | Global warming potential of $N_2O$ | $tCO_2e/tN_2O$ |

[22] It is only necessary to measure volume flow rate in one location, either upstream or downstream of the destruction facility because the system is closed and thus flow rate should be constant.

#### 5.2.4.2 Calculating Project Emissions from Ammonia Input

When an existing SCR unit is operating at the NAP prior to the project start date, the baseline and project ammonia input will be considered equal. This is because either (1) the function of the existing SCR is replaced by a combined unit (SCR and tertiary catalyst) or (2) the original SCR continues to operate and the new tertiary catalyst is not combined with an SCR unit. In both of these cases, the amount of ammonia input required to operate the NAP will not change relative to the baseline.

In cases where SCR is not operating at the NAP prior to the project start date and SCR is installed with the tertiary catalyst to improve $N_2O$ destruction efficiency, project emissions related to the production of ammonia used to run the SCR shall be calculated using Equation 5.13.

**Equation 5.13.** Project Emissions for Ammonia Input to Tertiary Catalyst

$$\boldsymbol{PE_{NH_3} = Q_{NH_3} \times 2.14}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{NH3}$ | = | GHG emissions from the ammonia input used to operate the tertiary catalyst facility during the reporting period | $tCO_2e$ |
| $Q_{NH3}$ | = | Ammonia input to the destruction facility during the reporting period | $tNH_3$ |
| 2.14 | = | GHG emission factor for ammonia production[23] | $tCO_2e/ tNH_3$ |

#### 5.2.4.3 Calculating Project Emissions from Hydrocarbon Use

Hydrocarbons can be used as a reducing agent or to reheat tail gas to enhance the catalytic $N_2O$ reduction efficiency, which leads to $CO_2$ and $CH_4$ emissions. The project emissions related to hydrocarbon input to the project shall be calculated using Equation 5.14.

**Equation 5.14.** Project Emissions from Hydrocarbon Use

$$\boldsymbol{PE_{HC} = CO_{2_{HC}} + CH_{4_{HC}}}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{HC}$ | = | GHG emissions from the use of hydrocarbons as a reducing agent or to reheat tail gas during the reporting period | $tCO_2e$ |
| $CO_{2,HC}$ | = | GHG emissions as $CO_2$ from hydrocarbon use during the reporting period (as calculated in Equation 5.15) | $tCO_2e$ |
| $CH_{4,HC}$ | = | GHG emissions as $CH_4$ from hydrocarbon use during the reporting period (as calculated in Equation 5.16) | $tCO_2e$ |

Hydrocarbons (organic compounds made up of carbon and hydrogen) are used primarily as a combustible fuel source (e.g. natural gas, which is mostly methane, propane, and butane).

[23] CDM methodology AM0028.

When hydrocarbons are combusted they produce heat, steam, and $CO_2$. For calculation of the GHG emissions related to hydrocarbons, assume all hydrocarbons other than $CH_4$ are completely converted to $CO_2$ (see Equation 5.15) and all $CH_4$ in the fuel or reducing agent is emitted directly as $CH_4$ to the atmosphere and is not converted to $CO_2$ (see Equation 5.16). In Equation 5.15, the hydrocarbon $CO_2$ emission factor ($EF_{HC}$) is given by the molecular weight of the hydrocarbon and $CO_2$ and the chemical reaction when hydrocarbons are converted.[24]

**Equation 5.15.** Project Carbon Dioxide Emissions from Hydrocarbon Use

$$CO_{2_{HC}} = \rho_{HC} \times Q_{HC} \times EF_{HC}$$

*Where,*

| | | | Units |
|---|---|---|---|
| $CO_{2,HC}$ | = | Converted hydrocarbon emissions during the reporting period | $tCO_2e$ |
| $\rho_{HC}$ | = | Hydrocarbon density | $t/m^3$ |
| $Q_{HC}$ | = | Quantity of hydrocarbon, with two or more molecules of carbon, input during the reporting period (i.e. not methane) | $m^3$ |
| $EF_{HC}$ | = | Carbon emission factor of hydrocarbon, with two or more molecules of carbon | $tCO_2e/tHC$ |

**Equation 5.16.** Project Methane Emissions from Hydrocarbon Use

$$CH_{4_{HC}} = \rho_{CH_4} \times Q_{CH_4} \times 21$$

*Where,*

| | | | Units |
|---|---|---|---|
| $CH_{4,HC}$ | = | Unconverted hydrocarbon emissions (methane) during the reporting period | $tCO_2e$ |
| $\rho_{CH4}$ | = | Methane density | $t/m^3$ |
| $Q_{CH4}$ | = | Methane used during the reporting period | $m^3$ |
| 21 | = | Global warming potential of methane | $tCO_2e/tCH_4$ |

### 5.2.4.4 Calculating Project Emissions from Tail Gas Reheating

If an external energy source is used to adjust tail gas temperatures at the inlet of the $N_2O$ destruction facility and the additional energy is not recovered before the tail gas is released to the atmosphere, then GHG emissions from the energy used shall be calculated and included in as project emissions using Equation 5.17.

[24] For example, where $CH_4$ is used as hydrocarbon, each converted tonne of $CH_4$ results in 44/16 tonnes of $CO_2$, thus the hydrocarbon emission factor is 2.75. (CDM methodology AM0028)

**Equation 5.17.** Project Emissions from Tail Gas Reheating

$$PE_{EE} = SE + TGU + TGH$$

*Where,*

| | | | Units |
|---|---|---|---|
| $PE_{EE}$ | = | Project emissions from external energy during the reporting period | $tCO_2e$ |
| SE | = | Emissions from net change in steam export during the reporting period (Equation 5.18) | $tCO_2e$ |
| TGU | = | Emissions from net change in tail gas utilization during the reporting period (Equation 5.19) | $tCO_2e$ |
| TGH | = | Emissions from net change in tail gas heating during the reporting period (Equation 5.20) | $tCO_2e$ |

**Equation 5.18.** Project Emissions from Steam Export

$$SE = \left[\frac{(ST_{BL} - ST_{PR}) \times OH_{RP}}{\eta_{ST}}\right] \times EF_{ST}$$

*Where,*

| | | | Units |
|---|---|---|---|
| SE | = | Emissions from net change in steam export during the reporting period | $tCO_2e$ |
| $ST_{BL}$ | = | Baseline steam export during a reporting period | MW |
| $ST_{PR}$ | = | Project steam export during the reporting period | MW |
| $OH_{RP}$ | = | Operating hours during the reporting period | hours |
| $\eta_{ST}$ | = | Efficiency of steam generation | % |
| $EF_{ST}$ | = | Fuel emission factor for steam generation | $tCO_2e$/MWh |

**Equation 5.19.** Project Emissions from Tail Gas Utilization

$$TGU = \left[\frac{(EE_{BL} - EE_{PR}) \times OH_{RP}}{\eta_r}\right] \times EF_r$$

*Where,*

| | | | Units |
|---|---|---|---|
| TGU | = | Emissions from net change in tail gas utilization during the reporting period | $tCO_2e$ |
| $EE_{BL}$ | = | Baseline energy export from tail gas utilization during a reporting period | MW |
| $EE_{PR}$ | = | Project energy export from tail gas utilization during the reporting period | MW |
| $OH_{RP}$ | = | Operating hours during the reporting period | hours |
| $\eta_r$ | = | Efficiency of replaced technology | % |
| $EF_r$ | = | Fuel emission factor for replaced technology | $tCO_2e$/MWh |

**Equation 5.20.** Project Emissions from Tail Gas Heating

$$TGH = \left[\frac{EI_{TGH}}{\eta_{TGH}}\right] \times EF_{TGH}$$

| *Where,* | | | Units |
|---|---|---|---|
| TGH | = | Emissions from net change in tail gas heating during the reporting period | $tCO_2e$ |
| $EI_{TGH}$ | = | Energy input for additional tail gas heating during the reporting period | MWh |
| $\eta_{TGH}$ | = | Efficiency of additional tail gas heating | % |
| $EF_{TGH}$ | = | Emission factor for additional tail gas heating | $tCO_2e/MWh$ |

# 6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan will serve as the basis for verifiers to confirm that the monitoring and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 or Table 6.2 (below) will be collected and recorded.

At a minimum, the Monitoring Plan shall stipulate the frequency of data acquisition, a record keeping plan, the frequency of instrument field check and calibration activities, the role of individuals performing each specific monitoring activity, as well as quality assurance/quality control (QA/QC) provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision.

Finally, the Monitoring Plan must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test (Section 3.4.1).

To ensure that all aspects of monitoring and reporting are met, the project developer shall follow the relevant guidance in this section as well as the relevant sections of the United States Code of Federal Regulations Title 40 (40 CFR), Part 60 and Part 75 as indicated below. Part 60 and Part 75 provide guidance on the standards of performance for stationary emission sources and continuous emission monitoring systems (CEMS) for $NO_X$ emission testing, which is also applicable to $N_2O$ emission testing at nitric acid production facilities. These parts outline the minimum requirements for the installation, evaluation, monitoring, and record keeping for CEMS (see Section 7.3 of this protocol for Reserve minimum record keeping requirements). Specifically, the project developer shall follow Appendix B of Part 75 that covers QA/QC procedures for CEMS.

If both Part 60 and Part 75 appear to address the same matter, then to the extent that their provisions are irreconcilably inconsistent, the Reserve intends the more specific provision to control/govern the subject and Part 75 to prevail over Part 60.

Project developers are responsible for monitoring the performance of the project and ensuring that the operation of the $N_2O$ abatement system is consistent with the manufacturer's recommendations for each component of the system. Installation and certification of the emission monitoring system in accordance with this section of this protocol should take place prior to the project start date. In addition, for secondary catalyst projects only, emission monitoring to establish baseline emissions should take place immediately prior to the project start date.

## 6.1 Monitoring Requirements

Direct measurements of the $N_2O$ concentration in the stack gas (and tail gas in the case of tertiary projects) and the flow rate of the stack gas/tail gas shall be made using a continuous emission monitoring system. CEMS is the most accurate monitoring method because $N_2O$

emissions are measured continuously from a specific source.[25] Elements of a CEMS include a platform and sample probe within the stack to withdraw a sample of the stack gas, an analyzer to measure the concentration of the $N_2O$ (typically a non-dispersive infrared sensor (NDIR) or Fourier transform infrared (FTIR) spectroscopy) in the stack gas, and a flow meter within the stack to measure the flow rate of the stack gas. The emissions are calculated from the concentration of $N_2O$ in the stack gas/tail gas and the flow rate of the stack gas/tail gas. A CEMS continuously withdraws and analyzes a sample of the gas and continuously measures the $N_2O$ concentration and flow rate of the gas.[26]

### 6.1.1 System Installation and Certification

The project developer shall follow the requirements for CEMS installation and initial certification detailed in section 60.13 of 40 CFR Part 60, Performance Specification 2 of Appendix B of 40 CFR Part 60, and section 6 of Appendix A of 40 CFR Part 75. CEMS must be installed and operational before conducting performance tests on the system. In order to achieve operational status, the project developer must show that the CEMS also meets manufacturer's requirements or recommendations for installation, operation, and calibration.

Projects utilizing a CEMS that was initially installed for a purpose other than the monitoring of a $N_2O$ abatement project (e.g. to monitor $NO_X$ abatement) must still meet all of the requirements of this section. If any of the required tests listed below were not conducted or the requirements were not met at the time of initial installation and certification, the project developer must conduct the tests and ensure that the requirements are met prior to beginning the baseline campaign.

The following initial certification requirements are summarized from 40 CFR Part 75. Please refer to the CFR sections referenced above for all installation and certification requirements.

- 7-day calibration error test to evaluate the accuracy and stability of a gas analyzer's or flow monitor's calibration over a period of unit operation.
- Linearity check to determine whether the response of the $N_2O$ concentration monitor is linear across its range by challenging CEMS with three different levels of calibration gas concentrations.
- Relative Accuracy Test Audit (RATA) to determine the accuracy of the system by comparing $N_2O$ emissions data recorded by the CEMS to data collected concurrently with an emission reference test method. All RATA of CEMS must be conducted by a testing body conforming to the requirements of ASTM D7036-04.[27]
- Bias test to ensure that the monitoring system is not biased low with respect to the reference method, based on RATA results.
- Cycle time test to ensure that the monitoring system is capable of completing at least one cycle of sampling, analyzing, and data recording every 15 minutes.[28]
- Automated data acquisition and handling system (DAHS) verification to ensure that all emission calculations are performed correctly and that the missing data substitution methods are applied properly.

[25] This method is consistent with Approach 1 from the World Business Council for Sustainable Development and the "A" rated approach from the U.S. Department of Energy.
[26] U.S. EPA *Technical Support Document for the Nitric Acid Production Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases*, Office of Air and Radiation, January 22, 2009.
[27] 40 CFR Part 75, Appendix A, section 6.1.2(a).
[28] 40 CFR Part 60, 60.13(e)(2).

### 6.1.2 Calibration

The calibration procedures from Performance Specification 2 of Appendix B of 40 CFR Part 60 and Appendix A of 40 CFR Part 75 shall be followed for CEMS measuring $N_2O$ emissions according to this protocol. Calibration test procedures are outlined in Performance Specification 2, Appendix B of Part 60 and section 6.3, Appendix A of Part 75. The performance specifications for the 7-day calibration error test and linearity check are described in section 3.1 and 3.2 of Appendix A of Part 75.

### 6.1.3 Accuracy Testing

The relative accuracy and RATA procedures from Appendix A and B (Performance Specification 2) of 40 CFR Part 60 and Appendix A of 40 CFR Part 75 shall be followed for CEMS used in nitric acid production projects. The guidance for $NO_X$ CEMS shall be used for $N_2O$ emission monitoring where the CEMS relative accuracy shall not exceed 10% at any operating level at which a RATA is performed.[29]

Because there is not a standard reference test method for $N_2O$ CEMS at this time, a RATA for the verification of a FTIR or NDIR installation for $N_2O$ analysis may use any of the following:

- U.S. EPA test method 320[30] for the measurement of vapor phase organic and inorganic emissions by extractive FTIR spectroscopy[31]
- ASTM D6348-03 method for the determination of gaseous compound by extractive direct interface FTIR spectroscopy[32]
- ISO/DIS 21258 stationary source emissions determination of the mass concentration of $N_2O$ reference method for NDIR[33]
- Other NDIR methods used in AM0034 or AM0028, or performance specification based reference method such as EPA method 7E.[34]

#### 6.1.3.1 Sampling

For all RATA, a minimum of nine test runs have to be conducted for a period of at least 21 minutes for each run. More test runs may be completed with the option to exclude up to three test runs from the audit. However, all data must be reported, including the rejected data.[35] For details on RATA sampling, see the relative accuracy test procedures and performance specifications in Performance Specification 2, Appendix B of 40 CFR Part 60 and Appendix A of 40 CFR Part 75.

## 6.2 QA/QC Requirements

The quality assurance and quality control (QA/QC) provisions required for this protocol shall be included in the Monitoring Plan and consistent in stringency, data reporting, and documentation with the CEMS QA/QC program described in Appendix B of 40 CFR Part 75 (see Section 7 of this protocol for further record-keeping requirements).

The following QA/QC requirements are summarized from Appendix B of 40 CFR Part 75. Please refer to the CFR sections referenced above for all QA/QC requirements.

[29] 40 CFR Part 75, Appendix A, section 3.3.4(a).
[30] http://www.epa.gov/ttn/emc/methods/method320.html
[31] 40 CFR Part 63, Appendix A.
[32] 40 CFR Part 60, 60.17(a)(82).
[33] http://www.iso.org/iso/catalogue_detail.htm?csnumber=40113
[34] http://www.epa.gov/ttn/emc/promgate/method7E.pdf
[35] 40 CFR Part 60, Appendix B, section 8.4.4.

- Procedures for preventative maintenance of the monitoring system
- Record keeping and reporting procedures
- Testing, maintenance, and repair activity records for CEMS or any component of CEMS
- Calibration error test and linearity check procedures
- Calibration and linearity adjustment procedures
- RATA procedures, such as sampling and analysis methods

### 6.2.1 Frequency of Testing

The schedule for the frequency of testing required for CEMS is described in section 2, Appendix B of 40 CFR Part 75. At a minimum, the following schedule must be followed for tests relevant to $N_2O$ analysis using CEMS.

Daily assessments to quality-assure the hourly data recorded by the CEMS as of the date when CEMS completes certification testing:

- Calibration error test for $N_2O$ analyzer
- Calibration adjustments for $N_2O$ analyzer
- Data validation
- Quality assurance
- Data recording

Quarterly assessments apply as of the calendar quarter following the calendar quarter in which the CEMS is provisionally certified:

- Calibration error test for flow meter
- Calibration adjustments for flow meter
- Linearity check in quarters for which there is no RATA
- Leak check for CEMS utilizing differential pressure flow meters
- Data validation
- Linearity and leak check grace period
- Flow-to-load ratio or gross heat rate evaluation for projects located at a nitric acid plant that produces either electrical or thermal output

Semiannual and annual assessments apply as of the calendar quarter following the calendar quarter in which the CEMS is provisionally certified:

- RATA
- Data validation
- RATA grace period
- Bias adjustment factor applied if a monitor fails the bias test

For CEMS that were installed and certified for $NO_X$ abatement prior to implementation of the $N_2O$ abatement project, the daily, quarterly, semi-annual, and annual assessments detailed above only need to be performed, documented, and verified as of the start of the baseline campaign, not as of the date when the CEMS originally completed certification testing for $NO_X$ abatement. For CEMS that were installed specifically for $N_2O$ abatement project implementation, assessments must be performed, documented, and verified as of the date that the CEMS was certified.

If the quarterly calibration error test reveals accuracy outside of a +/- 3% threshold, calibration by the manufacturer or a certified service provider is required for the flow meter. For the interval between the last successful calibration error test and the calibration error test that revealed accuracy outside +/- 3% threshold, conservativeness will determine what flow meter data are used in emission reduction calculations. Whether the calibration error is detected in a baseline or project campaign determines whether the metered values are used without correction or are adjusted based on the greatest calibration drift recorded at the time of calibration. The verification body shall confirm that any adjustments to the metered values result in the most conservative calculation of emission reductions. Any adjustments shall be made for the entire period from the last successful calibration error test until such time that the meter is properly calibrated and re-installed.

### 6.2.2 Data Management

Data management procedures are an important component of a comprehensive QA/QC plan. Data management procedures are described throughout Appendix B of 40 CFR Part 75 and include the following items.[36]

- Check for temporal consistency in production data and emission estimates. If outliers exist, an explanation could be required as to changes in the facility operations or other factors. A monitoring error is probable if differences between annual data cannot be explained by changes in activity levels, changes concerning fuels or input material, or changes concerning the emitting process.
- Determine the reasonableness of the emission estimate by comparing it to previous year's estimates.
- Maintain data documentation, including comprehensive documentation of data received through personal communication.
- Check that changes in data or methodology are documented.

## 6.3 Missing Data Substitution

In situations where the $N_2O$ CEMS is missing data, the project developer shall follow the missing data substitution procedures for $NO_X$ CEMS found in section 75.33 of 40 CFR Part 75. In summary, missing data from the operation of the CEMS may be replaced with substitute data to determine the $N_2O$ emissions during the period for which CEMS data are missing. The owner or operator of the CEMS can substitute for missing $N_2O$ concentration data using the procedures specified in section 75.33.[37]

For each hour of missing data, the project developer shall calculate substitute data for $N_2O$ concentration based on the previous 2,160 quality-assured monitor operating hours for the CEMS. The data substitution procedures depend on the percentile of available monitoring data from the system and the length of the missing data period. If there are no prior quality-assured data or minimal available data (the minimum percent is specified in section 75.33), the owner or operator must substitute the minimum potential $N_2O$ concentration for missing data in the baseline and the maximum potential $N_2O$ concentration for missing data in the project, per the following:

- Minimum – Baseline:

[36] The data management items are gathered from section 7.3 of the U.S. EPA *Technical Support Document for the Nitric Acid Production Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases*, Office of Air and Radiation, January 22, 2009.
[37] 40 CFR75, 75.33, Standard missing data procedures for $SO_2$, $NO_X$, Hg, and flow rate.

  - Secondary projects: $N_2O$ monitoring to establish the baseline
  - Tertiary projects: $N_2O$ monitoring at the inlet of the tertiary catalyst
- Maximum – Project:
  - Secondary projects: $N_2O$ monitoring for the project
  - Tertiary projects: $N_2O$ monitoring at the outlet of the tertiary catalyst

## 6.4 Monitoring Parameters for Secondary Catalyst Projects

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.1.

**Table 6.1.** Monitoring Parameters for Secondary Catalyst Projects

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| **General Project Parameters** | | | | | | |
| | Regulations | Project developer attestation of compliance with legal requirements relating to the project | All applicable regulations | n/a | Each verification | Information used to:<br><br>1) Demonstrate ability to meet the Legal Requirement Test – where regulation would require the abatement of $N_2O$ or the installation of certain $NO_X$ emission control technology that will impact $N_2O$ emissions<br>2) Demonstrate compliance with all applicable regulations, e.g. criteria pollutant emission standards, health and safety, etc. |
| | $OT_h$ | Oxidation temperature | °C | m | Every hour | The parameter is recorded every hour during baseline and project monitoring and compared with the normal range of oxidation temperature according to this protocol |
| | $OP_h$ | Oxidation pressure | bar | m | Every hour | The parameter is recorded every hour during baseline and project monitoring and compared with the normal range of oxidation pressure according to this protocol |
| | $OT_{normal}$ | Allowable range for oxidation temperature | °C | c | Once | To be obtained from the operating condition campaigns |

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| | $OP_{normal}$ | Allowable range for oxidation pressure | bar | c | Once | To be obtained from the operating condition campaigns |
| | | Ammonia-to-air ratio | % | m, c | Every hour | This parameter is monitored during the baseline and project campaigns. This percentage is calculated as $NH_3/(NH_3 + air)$, using units of either mass or volume |
| | | Maximum ammonia-to-air ratio | % | c | Once | To be obtained from the operating condition campaigns |
| | $CPV_{cap}$ | Campaign production volume cap | $tHNO_3$ | c | Once | This limits the length of the baseline sampling period by ending data collection when nitric acid production meets the value of the cap |
| 5.1 | ER | Emission reductions for the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.2 | $HNO_{3,MAX,scaled}$ | $HNO_{3,MAX}$, scaled to the length of the campaign | $tHNO_3$ | c | Once | |
| 5.2 | $HNO_{3,MAX}$ | Historical maximum annual average nitric acid production | $tHNO_3$/day | c | Once | Calculated from historical production data, averaged over 12 month intervals |
| 5.2 | $OD_n$ | Days of operation in the campaign for which $HNO_{3,MAX,scaled}$ is being calculated | days | o | Per campaign | |
| **Baseline Calculation Parameters** | | | | | | |
| 5.1, 5.3 | BE | Baseline emissions for the reporting period | $tCO_2e$ | c | Per reporting period | Emissions that would have occurred in the absence of the project activity, determined through the baseline sampling period |
| 5.3, 5.4 | $EF_{BL}$ | Baseline emission factor | $tN_2O/tHNO_3$ | c | Per reporting period | |

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| 5.3 | $HNO_{3,RP,scaled}$ | Quantity of nitric acid production used to quantify emission reductions, not exceeding $HNO_{3,MAX,scaled}$ | $tHNO_3$ | c | Per reporting period | Equal to the lesser of $HNO_{3,MAX,scaled}$ or $HNO_{3,RP}$ |
| 5.3, 5.10 | $EF_{New}$ | Default baseline emission factor for production above $HNO_{3,max,scaled}$ | $tN_2O/tHNO_3$ | r | Per reporting period, whenever necessary | Choose the default factor corresponding to the calendar year of the reporting period (see Table B.1). If a reporting period spans multiple calendar years, the more conservative (i.e. lower) $EF_{New}$ should be used. |
| 5.3 | $HNO_{3,New}$ | Quantity of nitric acid production by which $HNO_{3,RP}$ exceeds $HNO_{3,MAX,scaled}$ | $tHNO_3$ | c | Per reporting period | Equal to the difference between $HNO_{3,MAX,scaled}$ and $HNO_{3,RP}$ |
| 5.4, 5.5 | $N_2O_{BL}$ | Total $N_2O$ emissions during the baseline sampling period | $tN_2O$ | m | Continuously, totaled for the campaign | |
| 5.4 | $HNO_{3,BL}$ | Nitric acid (100% concentrated) produced over baseline campaign | $tHNO_3$ | o | Daily, totaled for the entire campaign | |
| 5.5 | $F_{BL}$ | Volume flow rate of the stack gas expressed in normal conditions (101.325 kPa, 0 °C) | $m^3$/hour | m | Every one minute | The data are collected using a gas volume flow meter and the data output will be processed using appropriate software programs |
| 5.5 | $N_2O_{conc,BL}$ | $N_2O$ concentration in the stack gas at normal conditions (101.325 kPa, 0 °C) | $tN_2O/m^3$ (converted from ppm if necessary) | m | Every one minute | The data are collected using a $N_2O$ analyzer and the data output will be processed using appropriate software programs |

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| 5.5 | $OH_{BL}$ | Operating hours | hours | o | Daily, totaled for the entire campaign | Plant manager records the hours of full operation of the plant during a campaign |
| **Project Calculation Parameters** | | | | | | |
| 5.1, 5.6 | PE | Project emissions for the reporting period | $tCO_2e$ | c | Per reporting period | Emissions resulting from project activities |
| 5.6, 5.7 | $N_2O_n$ | Total $N_2O$ emissions during the project campaign | $tN_2O$ | c | Per campaign | |
| 5.7 | $F_n$ | Volume flow rate of the stack gas expressed in normal conditions (101.325 kPa, 0 °C) | $m^3$/hour | m | Every one minute | The data are collected during a project campaign using a gas volume flow meter and the data output will be processed using appropriate software programs. The analyzer will be calibrated according to vendor specifications and recognized industry standards |
| 5.7 | $N_2O_{conc,n}$ | $N_2O$ concentration in the stack gas at normal conditions (101.325 kPa, 0 °C) | $tN_2O/m^3$ (converted from ppm if necessary) | m | Every one minute | The data are collected during a project campaign using a $N_2O$ analyzer and the data output will be processed using appropriate software programs. The analyzer will be calibrated according to vendor specifications and recognized industry standards |
| 5.7 | $OH_n$ | Operating hours during the project campaign | hours | o | Daily, totaled for the entire campaign | Plant manager records the hours of full operation of the plant during a campaign |

## 6.5 Monitoring Parameters for Tertiary Catalyst Projects

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.2.

**Table 6.2.** Monitoring Parameters for Tertiary Catalyst Projects

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| **General Project Parameters** | | | | | | |
| | Regulations | Project developer attestation of compliance with legal requirements relating to the project | All applicable regulations | n/a | Each verification | Information used to:<br><br>1) Demonstrate ability to meet the Legal Requirement Test – where regulation would require the abatement of $N_2O$ or the installation of certain $NO_X$ emission control technology that will impact $N_2O$ emissions<br>2) Demonstrate compliance with all applicable regulations, e.g. criteria pollutant emission standards, health and safety, etc. |
| | $OT_h$ | Allowable range for oxidation temperature | °C | c | Once | To be obtained from the operating condition campaigns |
| | $OT_a$ | Actual operating temperature range | °C | m | Every hour | The parameter is recorded every hour during baseline and project monitoring and compared with the normal range of oxidation temperature according to this protocol |
| | $OP_h$ | Allowable range for oxidation pressure | bar | c | Once | To be obtained from the operating condition campaigns |
| | $OP_a$ | Actual oxidation pressure | bar | m | Every hour | The parameter is recorded every hour during baseline and project monitoring and compared with the normal range of oxidation pressure according to this protocol |

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| | | Ammonia-to-air ratio | % | m, c | Every hour | This percentage is calculated as $NH_3/(NH_3 + air)$, using units of either mass or volume |
| | | Maximum ammonia-to-air ratio | % | c | Once | To be obtained from the operating condition campaigns |
| 5.8 | ER | Emission reductions for the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.9, 5.10 | $HNO_{3,MAX,scaled}$ | Historical maximum annual average nitric acid production | $tHNO_3$ | c | Once | Calculated from campaign-specific production data, averaged over 12 month intervals and scaled to the length of the reporting period |
| 5.9 | $HNO_{3,MAX}$ | The historical maximum annual average total output of 100% concentration nitric acid | $tHNO_3$/day | o | Once | |
| 5.9 | $OD_n$ | Number of days of operation during the project campaign | days | o | Per campaign | |
| **Baseline Calculation Parameters** | | | | | | |
| 5.8, 5.10 | BE | Baseline emissions for the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.10, 5.12 | $F_i$ | Volume flow rate, expressed in normal conditions (101.325 kPa, 0 °C) | $m^3$/hour | m | Every one minute | The data is collected using a gas volume flow meter and the data output will be processed using appropriate software programs |
| 5.10 | $N_2O_{conc,in,i}$ | $N_2O$ concentration at inlet to tertiary catalyst, expressed in normal conditions (101.325 kPa, 0 °C) | $tN_2O/m^3$ | m | Every one minute | The data is collected using a $N_2O$ analyzer and the data output will be processed using appropriate software programs |
| 5.10, 5.12 | $OH_i$ | Operating hours during interval i | hours | m, r | After every interval is completed | |

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| 5.10, 5.12 | $HNO_{3,RP}$ | Plant output of $HNO_3$ during the reporting period | $tHNO_3$ | m | Daily, totaled for the reporting period | |
| 5.10 | $BE_i$ | Baseline emissions during interval i when NAP is operating outside of AOC | $tCO_2e$ | c | Per interval whenever necessary | |
| 5.10 | $HNO_{3,i}$ | Total nitric acid produced during interval i when NAP is operating outside of AOC | $tHNO_3$ | m | Daily, totaled for the interval whenever necessary | |
| 5.10 | $EF_{IPCC}$ | IPCC default emission factor | $kgN_2O/$ $tHNO_3$ | r | Per interval whenever necessary | Choose the default factor corresponding to the calendar year of the reporting period (see Table B.1) |
| 5.18 | $ST_{BL}$ | Baseline steam export | MW | c | Once | |
| 5.19 | $EE_{BL}$ | Baseline energy export from tail gas utilization | MW | c | Once | |
| **Project Calculation Parameters** | | | | | | |
| 5.8, 5.11 | PE | Project emissions for the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.11, 5.12 | $PE_{N2O}$ | GHG emissions from $N_2O$ in the tail gas during the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.11, 5.13 | $PE_{NH3}$ | GHG emissions from the ammonia input used to operate the tertiary catalyst during the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.11, 5.14 | $PE_{HC}$ | GHG emissions from the use of hydrocarbons during the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.11, 5.17 | $PE_{EE}$ | GHG emissions from external energy used during the reporting period | $tCO_2e$ | c | Per reporting period | |

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| 5.12 | $N_2O_{conc,out,i}$ | $N_2O$ concentration at outlet of tertiary catalyst facility, expressed in normal conditions (101.325 kPa, 0 °C) | $tN_2O/m^3$ | m | Every one minute | The data is collected using a $N_2O$ analyzer and the data output will be processed using appropriate software programs |
| 5.13 | $Q_{NH3}$ | Project ammonia input | $tNH_3$ | m | Monthly | Measured if no SCR de-$NO_X$ unit is installed in the baseline scenario |
| 5.14, 5.15 | $CO_{2,HC}$ | GHG emissions as $CO_2$ from the use of hydrocarbons during the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.14, 5.16 | $CH_{4,HC}$ | GHG emissions as $CH_4$ from the use of hydrocarbons during the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.15 | $\rho_{HC}$ | Hydrocarbon density | $t/m^3$ | m | Per reporting period | |
| 5.15 | $Q_{HC}$ | Quantity of hydrocarbon input during the reporting period (not methane) | $m^3$ | o | Daily | |
| 5.15 | $EF_{HC}$ | Hydrocarbon emission factor (not methane) | $tCO_2/tHC$ | c | Per reporting period | Given by the molecular weight of the hydrocarbon and $CO_2$ and the chemical reaction when hydrocarbons are converted (CDM AM0028) |
| 5.16 | $\rho_{CH4}$ | Methane density | $t/m^3$ | m | Per reporting period | |
| 5.16 | $Q_{CH4}$ | Quantity of methane used during the reporting period | $m^3$ | o | Daily | |
| 5.17, 5.18 | SE | Emissions from net change in steam export during the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.17, 5.19 | TGU | Emissions from net change in tail gas utilization during the reporting period | $tCO_2e$ | c | Per reporting period | |

| Eq. # | Parameter | Description | Data Unit | Calculated (c) Measured (m) Reference (r) Operating Records (o) | Measurement Frequency | Comment |
|---|---|---|---|---|---|---|
| 5.17, 5.20 | TGH | Emissions from net change in tail gas heating during the reporting period | $tCO_2e$ | c | Per reporting period | |
| 5.18 | $ST_{PR}$ | Project steam export | MW | c | Once | |
| 5.18, 5.19 | $OH_{RP}$ | Operating hours during the reporting period | hours | o | Totaled once for reporting period | |
| 5.18 | $\eta_{ST}$ | Steam generation efficiency | % | c | Once | Based on manufacturer information |
| 5.18 | $EF_{ST}$ | Steam generator emission factor | $tCO_2e$/ MWh | c | Per reporting period | Based on fuel supplier certificate or default value |
| 5.19 | $EE_{PR}$ | Project energy export from tail gas utilization | MW | c | Once | |
| 5.19 | $\eta_r$ | Efficiency of replaced technology | % | c | Once | Based on manufacturer information |
| 5.19 | $EF_r$ | Fuel emission factor for replaced technology | $tCO_2e$/ MWh | c | Per reporting period | Based on fuel supplier certificate or default value |
| 5.20 | $EI_{TGH}$ | Additional energy input for tail gas heating | MWh | m or c | Monthly | |
| 5.20 | $\eta_{TGH}$ | Efficiency of additional tail gas heating | % | c | Once | Based on manufacturer information |
| 5.20 | $EF_{TGH}$ | Fuel emission factor for external tail gas heating | $tCO_2e$/ MWh | c | Per reporting period | Based on fuel supplier certificate or default value |

# 7 Reporting Parameters

This section provides guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure among project developers. Project developers must submit verified emission reduction reports to the Reserve annually at a minimum.

## 7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register a $N_2O$ abatement project.

- Project Submittal form
- Project diagram (diagram of the NAP showing where the project is located within the NAP, as well as location of monitoring equipment)
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form
- Verification Report
- Verification Statement

Project developers must provide the following documentation each reporting period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form

At a minimum, the above project documentation will be available to the public via the Reserve's online registry. Further disclosure and other documentation may be made available by the project developer on a voluntary basis. Project submittal forms and project registration information can be found at http://www.climateactionreserve.org/how/program/documents/.

## 7.2 Joint Project Verification

Because the protocol allows for multiple projects at a single nitric acid production facility, project developers have the option to hire a single verification body to verify multiple projects at a facility through a "joint project verification." This may provide economies of scale for the project verifications and improve the efficiency of the verification process.

Under joint project verification, each project, as defined by the protocol, is submitted for listing, listed, and registered separately in the Reserve system. Furthermore, each project requires its own separate verification process and Verification Statement (i.e. each project is assessed by the verification body separately as if it were the only project at the facility). However, all projects may be verified together by a single site visit to the facility. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Regardless of whether the project developer chooses to verify multiple projects through a joint project verification or pursue verification of each project separately, the documents and records for each project must be retained according to this section.

## 7.3 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

System information the project developer should retain includes:

- All data inputs for the calculation of the project emission reductions, including all required sampled data
- Copies of all solid waste, air, water, and land use permits, Notices of Violations (NOVs), and any administrative or legal consent orders dating back at least 3 years prior to the project start date, and for each subsequent year of project operation
- Project developer attestation of compliance with regulatory requirements relating to the $N_2O$ abatement project
- Plant design information (nameplate capacity and operating parameters per manufacturer's operating manual) and diagrams/drawings of the NAP
- Diagram schemes showing the type of and detailed components of the $N_2O$ abatement system and where it is or where it will be installed
- Automated extractive gas analyzer or monitor information (model number, serial number, calibration procedures)
- Gas volume flow meter information (model number, serial number, calibration procedures)
- Plans or diagram schemes showing the selection of data measuring points upstream and/or downstream to the $N_2O$ abatement system
- Calibration results for all meters
- Information relevant to the primary (ammonia oxidation) catalysts (composition, campaign lengths, installation, and maximum permitted ammonia gas flow rates and ammonia-to-air ratio as specified by the catalyst manufacturer)
- Information relevant to the $N_2O$ abatement catalysts (composition, campaign lengths, and installation)
- The total production of nitric acid per campaign and the number of operating hours
- $CO_2e$ annual tonnage calculations
- Initial and annual verification records and results
- All maintenance records relevant to the $N_2O$ abatement system and monitoring equipment

Calibrated gas analyzer information that the project developer should retain includes:

- Date, time, and location of $N_2O$ measurement
- $N_2O$ measurement instrument type and serial number
- Date, time, and results of instrument calibration
- Corrective measures taken if instrument does not meet performance specifications

## 7.4 Reporting Period and Verification Cycle

Project developers must report GHG reductions resulting from project activities during each reporting period. Although projects must be verified annually at a minimum, the Reserve will accept verified emission reduction reports on a nitric acid production campaign basis, should the campaign length be shorter than one year and the project developer chooses to have a sub-annual reporting period and verification schedule. A reporting period may not exceed 12 months in length, and no more than 12 months of emission reductions may be verified at once, except during a project's first verification, which may include historical emission reductions from prior years. Reporting periods must be contiguous; there must be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced. A reporting period must represent a full campaign, defined as the full length of operation of one set of primary catalyst gauzes (i.e. the time between new catalyst installations or new charges of catalyst gauze), except as otherwise allowed in Section 7.4.1. Occasionally, certain types of maintenance activities may be required at the plant that may interrupt project activities. Such maintenance periods, defined as a period during which no ammonia is flowing and no nitric acid is produced, are permissible with the following caveats to ensure continuous reporting for the project:

- Maintenance periods must be included within the dates of a reporting period to ensure continuous reporting.
- The data generated during the maintenance period (e.g. OH, F, $N_2O_{conc}$, T, P) shall be excluded when performing the calculations in Section 5.
- Monitoring equipment may be removed during these maintenance periods, as necessary, and the related QA/QC requirements may be suspended during that time.
- Once production commences following a maintenance period, daily QA/QC requirements must be met, and the schedule of quarterly, semi-annual, and annual QA/QC requirements must resume in a timely manner, so as to continue to meet the requirements of Section 6.
- The project developer must demonstrate to the verifier that no ammonia was flowing and no nitric acid was produced during a maintenance period.

If a campaign spans multiple calendar years, then the emission reductions shall be calculated for the entire campaign, and then scaled for each vintage year based on operating hours.

### 7.4.1 Sub-Campaign Verification

A project developer may choose to verify a reporting period that spans less than a full campaign (as defined above). Any such reporting period is referred to as a "sub-campaign reporting period." For any sub-campaign reporting period whose end date is prior to the completion date of a full campaign, the project developer must apply a 5% discount to the total emission reductions quantified and reported for that reporting period (the results of either Equation 5.1 or Equation 5.8). Upon completion of the full campaign, the project developer must quantify the emission reductions for the entire campaign, following the guidance in Section 5. The emission reductions reported for the final sub-campaign reporting period shall be equal to the reductions quantified over the full campaign minus the sum of emission reductions that were reported for prior sub-campaign reporting periods within the same campaign (see Box 7.1 for an example).

**Box 7.1.** Quantification of Sub-Campaign Reporting Periods

This methodology was developed to allow project developers increased flexibility in the reporting and registration of emission reductions from nitric acid production projects. Due to the potential risk of overestimation from this practice, the quantification of sub-campaign reporting periods differs slightly from the quantification of a full campaign reporting period.

**Example:**

A nitric acid plant operates a full campaign of its primary gauze from the first day of January through the last day of October of the same year. The project developer wishes to split this campaign into two reporting periods of equal length, each representing five months of data. The tables below illustrate the emission reductions that would be reported in this scenario, compared to what would be reported if the developer chose full campaign verification.

**Sub-campaign quantification**

| Reporting Period | Baseline Emissions | Project Emissions | Calculated Emission Reductions | Deduction | Reported Emission Reductions |
|---|---|---|---|---|---|
| January – May | 300,000 | 200,000 | 100,000 | 5,000 (5% discount) | **95,000** |
| June – October | 600,000 | 400,000 | 200,000 | 95,000 (previously reported emission reductions) | **105,000** |
| | | | | **Total for campaign** | **200,000** |

**Full campaign quantification**

| Reporting Period | Baseline Emissions | Project Emissions | Calculated Emission Reductions | Deduction | Reported Emission Reductions |
|---|---|---|---|---|---|
| January – October | 600,000 | 400,000 | 200,000 | 0 | **200,000** |
| | | | | **Total for campaign** | **200,000** |

**Note:** This example and the calculations are simplified for illustrative purposes.

# 8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions from projects developed to the standards of this protocol. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities in the context of reducing nitrous oxide emissions through secondary and tertiary abatement projects at nitric acid plants.

Verification bodies trained to verify nitric acid production projects must conduct verifications to the standards of the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve Nitric Acid Production Project Protocol

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only ISO-accredited verification bodies trained by the Reserve for this project type are eligible to verify nitric acid production project reports. Verification bodies approved under other project protocol types are not permitted to verify nitric acid production projects. Information about verification body accreditation and Reserve project verification training can be found in the Verification Program Manual.

## 8.1 Verification of Multiple Projects at a Single Nitric Acid Production Facility

Because the protocol allows for multiple projects at a single nitric acid production facility, project developers have the option to hire a single verification body to verify multiple projects under a joint project verification. This may provide economies of scale for the project verifications and improve the efficiency of the verification process. Joint project verification is only available as an option for a single project developer; joint project verification cannot be applied to multiple projects registered by different project developers at the same facility.

Under joint project verification, each project, as defined by the protocol, must be registered separately in the Reserve system and requires its own verification process and Verification Statement (i.e. each project is assessed by the verification body separately as if it were the only project at the facility). However, all projects may be verified together by a single site visit to the facility. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Finally, the verification body may submit one Notification of Verification Activities/Conflict of Interest (NOVA/COI) Assessment form that details and applies to all of the projects at a single facility that it intends to verify.

If during joint project verification, the verification activities of one project are delaying the registration of another project, the project developer can choose to forego joint project verification. There are no additional administrative requirements of the project developer or the verification body if joint project verification is terminated.

## 8.2 Sub-Campaign Verification

Per Section 7.4.1, a project developer may choose to verify a reporting period that spans less than a full campaign (i.e. sub-campaign reporting period). When a project developer has reported on a sub-campaign basis, the verification body must ensure that the discounts and deductions in Section 7.4.1 have been applied correctly. Specifically, when verifying the final reporting period of a campaign, the verification body must confirm the emission reduction calculations for the entire campaign, not just the final reporting period. The verification body does not need to reconfirm any eligibility requirements, QA/QC requirements or calculations for previously registered sub-campaign reporting periods. The verification body does need to confirm that the calculations for the final reporting period of a campaign are based on data from the full campaign, including any data previously verified for the prior sub-campaign reporting periods.

## 8.3 Standard of Verification

The Reserve's standard of verification for nitric acid production projects is the Nitric Acid Production Project Protocol, the Reserve Program Manual, and the Verification Program Manual. To verify a nitric acid production project developer's project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Sections 2 through 7 of this protocol. Sections 2 through 7provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

## 8.4 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 and Table 6.2 are collected and recorded.

## 8.5 Verifying Eligibility Criteria

Verification bodies must affirm nitric acid production project eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for a nitric acid production project. This table does not represent all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items lists in Section 8.6.

**Table 8.1.** Summary of Eligibility Criteria

| Eligibility Rule | Eligibility Criteria | Frequency of Rule Application |
|---|---|---|
| Start Date | Start date may be no more than 6 months prior to project submittal | Once during first verification |
| Location | United States and its territories | Once during first verification |
| Performance Standard | ▪ Secondary catalyst projects: installation of a secondary $N_2O$ abatement catalyst in a nitric acid plant<br>▪ Tertiary catalyst projects: installation of a tertiary $N_2O$ abatement catalyst or NSCR in a nitric acid plant | Once during first verification |
| Legal Requirement Test | Signed Attestation of Voluntary Implementation form and monitoring procedures that lay out procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test | Every verification |
| Regulatory Compliance Test | Signed Attestation of Regulatory Compliance attesting that project is in material compliance with all applicable laws | Every verification |
| Exclusions | ▪ Nitric acid plants that are restarted any time after December 2, 2007, after being out of operation for a period of 24 months or longer<br>▪ New nitric acid plants constructed after December 2, 2009, with the exception of new nitric acid plants for which a permit application for construction was submitted to the appropriate government authorities prior to December 2, 2009<br>▪ Secondary catalyst projects at existing nitric acid plants where NSCR is currently operating<br>▪ Secondary catalyst projects at existing nitric acid plants that used NSCR technology at any point since December 2, 2007 | Every verification |

## 8.6 Core Verification Activities

The Nitric Acid Production Project Protocol provides explicit requirements and guidance for quantifying GHG reductions associated with reducing $N_2O$ emissions at nitric acid plants. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a nitric acid production project, but verification bodies shall also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emission sources, sinks, and reservoirs
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

**Identifying emission sources, sinks, and reservoirs**
The verification body reviews for completeness the sources, sinks, and reservoirs identified for a project.

**Reviewing GHG management systems and estimation methodologies**
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the facility operator uses to gather data on plant operations and $N_2O$ emissions and to calculate baseline and project emissions.

**Verifying emission reduction estimates**
The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

## 8.7 Nitric Acid Production Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a nitric acid production project. The tables include references to the section in the protocol where requirements are further described. The tables also identify items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve’s verification process and professional judgment, please see the Verification Program Manual.

***Note: These tables should not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to nitric acid production projects that must be addressed during verification.***

### 8.7.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance regarding eligibility and Climate Reserve Tonne (CRT) issuance for nitric acid production projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any one requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or subset of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

**Table 8.2.** Eligibility Verification Items

| Protocol Section | Eligibility Qualification Item | Apply Professional Judgment? |
|---|---|---|
| 2.1 – 2.1.3 | Verify that the project meets the project definition and is properly defined as a secondary catalyst or tertiary catalyst project | No |
| 2.1 | Verify whether the nitric acid plant is existing, upgraded, relocated or restarted | No |
| 2.2 | Verify ownership of the reductions by reviewing the Attestation of Title | No |
| 3.1 | Verify that the project only consists of activities at a single nitric acid plant at a nitric acid production facility operating within the U.S. or its territories | No |

| Protocol Section | Eligibility Qualification Item | Apply Professional Judgment? |
|---|---|---|
| 3.2 | Verify eligibility of project start date | No |
| 3.2 | Verify accuracy of project start date based on operational records | Yes |
| 3.3 | Verify that project is within its 10-year crediting period | No |
| 3.4.1 | Verify that the project meets the appropriate Performance Standard Test for the project type | No |
| 3.4.2 | Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the Legal Requirement Test | No |
| 3.4.2 | Confirm that neither the Title V nor PSD permit for the NAP includes language requiring installation of a secondary or tertiary catalyst | No |
| 3.4.2 | Verify that the Monitoring Plan contains procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test at all times | Yes |
| 3.5 | Verify that the project activities comply with applicable laws by reviewing any instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form | Yes |
| 6 | Verify that monitoring meets the requirements of the protocol. If it does not, verify that a variance has been approved for monitoring variations | No |
| 6.1 – 6.3 | Verify that all components of the CEMS adhered to the field check and calibration schedule specified in the protocol. If they do not, verify that a variance has been approved for monitoring variations or that adjustments have been made to data per the protocol requirements | No |
| 6.1.1 | Verify that installation and initial certification of the $N_2O$ CEMS were completed according to manufacturer specifications and the requirements of this protocol | No |
| 6.1.2 | Verify that the calibration test procedures were properly followed, including the calibration error test and linearity check | No |
| 6.1.3 | Verify that the relative accuracy test audits were completed according to the required procedure and schedule | No |
| 6.3 | If used, verify that data substitution methodology was properly applied | No |
| n/a | If any variances were granted, verify that variance requirements were met and properly applied | Yes |

### 8.7.2 Quantification of GHG Emission Reductions

Table 8.3 lists the items that verification bodies shall include in their risk assessment and recalculation of the project GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

**Table 8.3.** Quantification Verification Items

| Protocol Section | Quantification Item | Apply Professional Judgment? |
|---|---|---|
| 4 | Verify that SSRs included in the GHG Assessment Boundary correspond to those required by the protocol and those represented in the project diagram for the reporting period | No |
| 5.1.1, 5.2.1 | Verify that the project developer has correctly calculated and applied $HNO_{3,MAX,scaled}$ | No |

| Protocol Section | Quantification Item | Apply Professional Judgment? |
|---|---|---|
| 5.1.2, 5.2.2 | Verify that the project developer correctly calculated allowable operating ranges for temperature and pressure, and maximum ammonia flow rates and ammonia-to-air ratios, and note which method was used | No |
| 5.1.3.1 | Verify that the project developer correctly accounted for the operating conditions and parameters in the baseline sampling period for the secondary catalyst project | No |
| 5.1.3.2, 5.1.4.1 | Verify that the project developer correctly calculated the baseline and project $N_2O$ emission factors for the secondary catalyst project | No |
| 5.2.3, 5.2.4 | Verify that the project developer correctly accounted for $N_2O$ emissions at the inlet and outlet of the destruction facility for the tertiary catalyst project | No |
| 5.2.4.2 | Verify that the project developer correctly quantified ammonia input to the tertiary catalyst project or correctly assumed no change in ammonia input | No |
| 5.2.4.3 | Verify that the project developer correctly quantified hydrocarbon use for tertiary catalyst project | No |
| 5.2.4.4 | Verify that the project developer correctly quantified external energy inputs or was correct in not estimating this source due to capture and use of the additional energy within the system | Yes |
| 5.1.4, 5.2.4 | Verify that the project emissions calculations were calculated according to the protocol with the appropriate data | No |
| 7.4.1 | If the project developer has elected to divide a campaign into sub-campaign reporting periods, verify that the quantification is executed according to guidance in the protocol | No |

### 8.7.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

**Table 8.4.** Risk Assessment Verification Items

| Protocol Section | Item that Informs Risk Assessment | Apply Professional Judgment? |
|---|---|---|
| 6 | Verify that the project monitoring plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project | Yes |
| 6 | Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol | No |
| 6 | Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function | Yes |
| 6 | Verify that appropriate training was provided to personnel assigned to greenhouse gas reporting duties | Yes |
| 6 | Verify that all contractors are qualified for managing and reporting greenhouse gas emissions if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor’s work | Yes |
| 6, 7.3 | Verify that all required records have been retained by the project developer | No |

## 8.8 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project's verified status.

As stated in Section 8.1, project developers may choose to have a verification body conduct multiple project verifications at a single facility under a joint project verification. The verification body must verify the emission reductions entered into the Reserve system for each project and upload a unique Verification Statement for each project within the joint verification. The verification body can prepare a single Verification Report that contains information on all of the projects, but this must also be uploaded to every project under the joint verification.

# 9 Glossary of Terms

| | |
|---|---|
| Allowable operating conditions (AOC) | Operating conditions of the nitric acid plant must be established for the oxidation temperature range, oxidation pressure range, and the maximum ammonia-to-air ratio input to the ammonia oxidation reactor. These conditions ensure that $N_2O$ emissions during the baseline sampling period are representative of typical historical $N_2O$ emissions for the nitric acid plant and that baseline conditions are comparable to project conditions. See Section 5.1.2 for further detail. |
| Ammonia-to-air ratio | The ammonia-to-air ratio is represented as $NH_3/(NH_3 + \text{air})$, using units of either mass or volume. The term AIFR or 'air input flow rate' is sometimes used to refer to the ammonia-to-air ratio. |
| Baseline sampling period | Determination of baseline emission factor through continuous monitoring of $N_2O$ concentration and gas flow volume for a minimum of the first ten weeks after the start of a campaign and prior to secondary catalyst installation. |
| Campaign | The full length of operation of one set of primary catalyst gauzes (i.e. the time between new catalyst installations or new charges of catalyst gauze). |
| Continuous emission monitoring system (CEMS) | The monitoring system required under this project protocol for all projects for the direct measurement of the $N_2O$ concentration in the stack gas and the flow rate of the stack gas. |
| Effective Date | The date of adoption of this protocol by the Reserve Board. |
| Existing NAP | Refers to a NAP with an existing ammonia oxidation reactor operating at existing production capacity. |
| Joint project verification | Project verification option where a project developer hires a verification body to verify multiple projects at a nitric acid production facility. |
| Nitric acid ($HNO_3$) | 100% concentrated nitric acid. |
| Nitric acid plant (NAP) | A facility producing nitric acid by either a pressure or atmospheric pressure process from a single process unit. |
| NSCR | Non-selective catalytic reduction system designed originally for $NO_X$ abatement, which may qualify as a tertiary catalyst project provided the project requirements under this protocol are met. |
| Operating manual | An operating manual for NAP equipment is defined as one or more current, detailed, engineering document(s) that |

| | |
|---|---|
| | establish operational constraints and optimal ranges for temperature, pressure, and ammonia-to-air ratio, developed for the NAP by either the NAP equipment manufacturer or a third-party engineering firm that manages NAP equipment use, upgrade, and replacement. |
| Project diagram | A diagram of the NAP equipment and processes. |
| Relocated NAP | A NAP that has been moved from another geographic location to its current location. |
| Reporting period | Specific time period of project operation for which the project developer has calculated and reported emission reductions and is seeking verification and registration. It can be no more than 12 months. |
| Restarted NAP | A NAP that commenced production after December 2, 2007 after being out of operation for 24 months or less. |
| Secondary catalyst project | A $N_2O$ emission reduction project that installs and operates a dedicated $N_2O$ abatement catalyst inside or immediately below the ammonia oxidation reactor. |
| Stack gas | Gases in the stack, after any $NO_X$ or tertiary abatement, to be emitted into the atmosphere. |
| Sub-campaign reporting period | A reporting period that spans a period of time less than a full length of a campaign. |
| Tail gas | All gases (e.g. $NO_X$ and $N_2O$) exiting the absorbing tower before any $NO_X$ or tertiary abatement. |
| Tertiary catalyst project | A $N_2O$ emission reduction project that installs and operates a dedicated $N_2O$ abatement catalyst in the tail gas leaving the absorption tower (catalytic decomposition) or a NSCR unit. |
| Upgraded NAP | A NAP that has been modified in any way to increase production capacity and/or design capacity prior to the project start date or any time during the project crediting period. |
| Verification cycle | The Reserve requires verification of projects annually but does not require verifications to be completed on specific dates. Project developers select the reporting period to be verified. Thus, each project has a unique verification cycle that begins the first time a project is verified, occurs at least annually, and ends once the crediting period expires or the project is no longer eligible, whichever happens first. |

# 10 References

California Air Resources Board (May 2008). Clearinghouse of Technological options for Reducing Anthropogenic Non-$CO_2$ GHG Emissions from All Sectors. Available at: http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm#Nitrous_Oxide.

Casey Delhotal (April 2005). International Non-$CO_2$ Greenhouse Gas Marginal Abatement Report, Draft Methane and Nitrous from Non-Agricultural Sources Chapter 6, U.S. Environmental Protection Agency, Washington, D.C.

Clean Air Act Amendments of 1970, Pub. L. No.91-604, 84 Stat. 1683 (Dec. 31, 1970). 49 Fed. Reg. 13654.

Infomil and Novem (October 2001). Reduction of nitrous oxide (N2O) in the Nitric Acid Industry, Den Haag/Utrecht, The Netherlands. Available at: http://www.infomil.nl/legsys/bref/N2O_finaldocument.pdf

Intergovernmental Panel on Climate Change (IPCC) (2006). National GHG Inventory Guidelines. Volume 3 Industrial Processes, Section 3: Nitric Acid Production.

J. Perez-Ramirez, F. Kapteijn, K.Schoffel, J.A. Moulijn (2003). Formation and control of N2O in nitric acid production N: Where do we stand today? Applied Catalysis B: Environmental 44, p.117-151.

State of Georgia, Department of Natural Resources Air Protection Branch (June 2004). Preliminary Determination of the on SIP Permit Application No.14213. Prevention of Significant Air Quality Deterioration Review of PCS Nitrogen Fertilizer- Augusta Plant. Available at: http://www.georgiaair.org/airpermit/downloads/permits/24500002/tv14213/2450002pd.pdf

United Nations Framework Convention on Climate Change, Clean Development Mechanism (2011). Approved consolidated baseline and monitoring methodology ACM0019, *$N_2O$ abatement from nitric acid production* (Version 1.0).

United Nations Framework Convention on Climate Change, Clean Development Mechanism (2009). Approved consolidated baseline and monitoring methodology AM0028, *Catalytic reduction of $N_2O$ in the tail gas of Nitric Acid or Caprolactam Production Plants* (Version 4.2).

United Nations Framework Convention on Climate Change, Clean Development Mechanism (2009). Approved consolidated baseline and monitoring methodology AM0034, *Catalytic reduction of $N_2O$ inside the ammonia burner of nitric acid plants* (Version 3.3).

U.S. Environmental Protection Agency, Office of Air and Radiation (January 2009). Technical Support Document for the Nitric Acid Production Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases.

U.S. Environmental Protection Agency (December 1991). EPA Alternative Control Techniques Document—Nitric and Adipic Acid Manufacturing Plants, EPA- 450/3-91-026.

U.S. Environmental Protection Agency OAQPS (April 1984). Review of New Source Performance Standards for Nitric Acid Plants, EPA-450/3-84-011.

U.S. Environmental Protection Agency (2003). International Analysis of Methane and Nitrous Oxide Abatement Opportunities. Report to Energy Modeling Forum, Working Group 21. Appendices "Nitrous Oxide Baselines." Washington, DC: U.S. EPA. Available at: http://www.epa.gov/climatechange/economics/international.html.

U.S. Environmental Protection Agency (2006). Global Anthropogenic Non-$CO_2$ Greenhouse Gas Emissions: 1990–2020. Washington, DC: U.S. EPA.

U.S. Environmental Protection Agency (June 3, 2010). Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. 40 CFR Parts 51, 52, 70 and 71. Available at: http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf.

U.S. Environmental Protection Agency (April 2011). 2011 U.S. Greenhouse Gas Inventory Report Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. Available at: www.epa.gov/climatechange/emissions/usinventoryreport.html.

World Resources Institute and World Business Council for Sustainable Development. (2005). *The Greenhouse Gas Protocol for Project Accounting*. Part I, Chapter 4.

40 CFR §75, Continuous Emission Monitoring. Available at: http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr75_main_02.tpl.

# Appendix A Summary of Performance Standard Development

The following performance standard analysis was conducted for the development of the Nitric Acid Production Project Protocol Version 1.0. Regulatory requirements affecting nitric acid production facilities have been fully updated in Section 3 of this protocol.

## A.1 Federal and State Regulations

A comprehensive review of federal regulations and standards that apply to monitoring and controlling air emissions from nitric acid plants was undertaken by the Reserve, including the New Source Performance Standard and New Source Review programs under the Clean Air Act. The review found that while $N_2O$ emissions from nitric acid production are not regulated – entities responsible for the production of nitric acid are not required to report on or limit $N_2O$ emissions from their facilities – existing federal air quality regulations do limit $NO_X$ emissions from nitric acid production, which may require the use of $NO_X$ emission controls for some facilities.

Under 1998 EPA $NO_X$ Transport Rule (also known as the EPA $NO_X$ SIP Call),[38] EPA called for 23 states in Eastern U.S. to revise their State Implementation Plans (SIPs) and $NO_X$ budget or emission targets for each of these states to achieve ozone attainment. It also set up a $NO_X$ emissions trading program in which the states could participate. The definition of $NO_X$ under the $NO_X$ SIP is "the sum of nitric oxide and nitrogen dioxide in the flue gas or emission point, collectively expressed as nitrogen dioxide."[39] There is no specific federal mandate to the states to regulate or monitor $N_2O$ in the revision of their SIPs.

In response to federal and state regulations, most nitric acid production facilities in the United States are operating some form of $NO_X$ emission controls. As discussed further below, $NO_X$ emission controls can indirectly impact $N_2O$ emissions and therefore the extent to which specific technologies are deployed at nitric acid plants was evaluated to identify common practice for $NO_X$ and incidentally $N_2O$ emission controls.

Nitric acid plants with a Title V permit or that are subject to NSPS are required to implement certain monitoring requirements in accordance with Title 40 of the Code of Federal Regulations Part 75 on continuous emission monitoring systems. EPA has also issued a Rule for Mandatory Reporting of Greenhouse Gases under which nitric acid plants are required to report annual GHG emissions data starting in 2010. Nitric acid plants are to undergo an annual performance test under normal operating conditions, without $N_2O$ emissions controls operating, and to use the emissions data to derive a site specific emission factor. Alternatively, nitric acid plants can use CEMS for $N_2O$ to measure and report $N_2O$ emissions. The mandatory reporting rule does not require implementation of actions to reduce $N_2O$ emissions.

Under the Clean Air Act, the EPA has also been developing the Clean Power Plan, which will set standards for power plants and drive emission reductions at the state level. Though the U.S. Supreme Court stayed implementation of the Clean Power Plan on February 9, 2016, the Reserve does not anticipate the Clean Power Plan requiring any emission reductions or

[38] See 40 CFR. §51.121 & §51.122 and http://www.epa.gov/air/urbanair/nox/effrt.html.
[39] See 40 CFR. §51.9.

installation of emission reduction technology at nitric acid plants, such as those eligible under this protocol.[40]

## A.2 $NO_X$ Emission Controls

There are three commonly used $NO_X$ emission control technologies in the U.S.: NSCR, SCR, and extended absorption, with average $NO_X$ control efficiencies of 97.7%, 86.0-97.2%, and 94.6%, respectively.[41]

### NSCR

NSCR is added after the ammonia burner and treats the absorber tail gas before it is emitted to the atmosphere. It uses a catalyst to consume oxygen in the tail gas of the absorber, converts $NO_2$ to NO (to decolor the tail gas) and reduces NO to elemental N.[42] Additional fuel is required to run NSCR and an energy recovery unit must also be installed to handle excess heat generated by NSCR. The process is "non-selective" because all oxygen present in the tail gas is consumed, thus limiting all reactions requiring $O_2$, including reactions that produce $N_2O$. Some suggest that NSCR may destroy up to 80-90% of all $N_2O$ produced during nitric acid production.[43] Others report NSCR $N_2O$ control efficiency of about 70%.[44]

NSCR was commonly installed in new plants built in the 1970s. NSCR can be operated at any pressure, retrofitted to new plants, used in conjunction with other $NO_X$ control techniques, and heat generated by NSCR can be recovered and used to supply energy for process compression.

### SCR

Like NSCR, SCR is also added after the ammonia burner and treats the absorber tail gas before it is emitted to the atmosphere. However, SCR uses ammonia, $O_2$, and a catalyst to reduce $NO_X$ to elemental N. The ammonia preferentially reacts with $NO_X$, making it a selective process.[45] SCR requires the use of additional ammonia, can operate at any pressure, can be retrofitted to existing low-pressure plants and is well suited for new plant applications. There are costs savings to SCR relative to NSCR because it does not cause the same high temperatures and thus energy recovery equipment is not required.[46] Beginning in the late 1970s, NSCR technology started to be replaced by SCR technology. However, older plants designed around NSCR would likely require a complete redesign of the existing plant to replace the NSCR $NO_X$ control system with SCR and this is not considered by industry to be practical or economic.[47] SCR can have at least a slight unintentional impact on $N_2O$ emissions (+/- <5% of total emissions).

### Extended Absorption

Extended absorption improves production efficiency of $HNO_3$ by increasing the absorption of $NO_2$ in the absorption tower. As a result, less $NO_2$ is available to convert to $NO_X$, thereby lowering $NO_X$ emissions. This is achieved by increasing the volume and number of absorption

[40] EPA, "Clean Power Plan for Existing Power Plants," https://www.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants
[41] EPA-450/3-91-026: Alternative Control Techniques Document: Nitric and Adipic Acid Manufacturing Plants (1991).
[42] Ibid.
[43] Personal communication with project developers.
[44] Value provided by ClimeCo (project developers) based on NSCR N2O removal testing by a few of their customers.
[45] Ibid.
[46] Ibid.
[47] Based on a stationary source permit review for the construction and operation of modifications at a PCS Nitrogen facility located in Augusta, Georgia, published by the Georgia Department of Natural Resources.

trays, which is accomplished either by adding a second absorption tower or extending the height of an existing tower.[48] Because of the production efficiencies involved, extended absorption is a standard component of new facilities and a common add-on to old ones. New plants are generally designed with a single large tower and retrofits typically involve adding a second absorption tower in series. Extended absorption is believed to have no impact on $N_2O$ emissions.

## A.3 Current Industry Practice for using $NO_X$ Emission Controls

The U.S. EPA maintains a facility-level database to support development of the U.S. national greenhouse gas inventory and published a summary of these data in a technical support document (TSD) for the mandatory GHG reporting rule.[49] The EPA database was assembled from permit data and personal communications with nitric acid facility contacts.

Members of the Nitric Acid Production Project Protocol stakeholder workgroup (assembled for the development of this protocol) provided additional information to expand the database. For example, Terra Industries provided the Reserve with data on nine process units it owns and operates in the U.S. These data were used to fill some gaps in the EPA database and to describe two additional process units not in the EPA database.

According to the EPA database, there are 45 nitric acid production facilities operating in 25 states with a total of 65 process units (plants). The EPA database and information provided by Terra Industries were used to summarize data on $NO_X$ emission control technologies currently in use at 34 $N_2O$ plants in the U.S. In addition, two workgroup members provided summary data based on their knowledge of the industry and confidential industry surveys. Trends from all sources are shown in Table A.1.

All data sources show SCR as the most common $NO_X$ emission control technology currently in use, with market penetration of at least 75%. However, the EPA database appears to under-represent the number of process units with NSCR currently installed. Therefore, market penetration for NSCR is more difficult to pinpoint. These data suggest NSCR installations range from 6% to 20% (i.e. 4 to 13 process units).

**Table A.1.** Current Industry Practice for Use of $NO_X$ Emission Control Technologies

| | EPA Database (N=34) % (n) | Workgroup Report 1 (N≈40) % (n) | Workgroup Report 2 (N=60) % (n) |
|---|---|---|---|
| SCR | 76.47% (26) | 75% (30) | 80% (48) |
| Extended absorption | 11.76% (4) | --- | --- |
| NSCR | 5.88% (2) | 20% (8) | 20% (12) |
| None | 5.88% (2) | 2.5% (1) | --- |
| Other (peroxide-based $NO_X$ abatement) | --- | 2.5% (1) | --- |

According to the EPA data, extended absorption is used by less than a quarter of process units. No information on extended absorption was provided by workgroup members, because it is not widely considered by the industry as an emission control technology *per se*, but rather a standard for production efficiency. The EPA data are surprising, given reports that extended

[48] Ibid.
[49] http://epa.gov/climatechange/emissions/downloads/tsd/TSD%20Nitric%20Acid%20_EPA%201-22-09.pdf

absorption is a cost-effective means to increase $HNO_3$ production and a standard component of facilities. The Reserve suspects that the EPA database underestimates the number of plants operating with extended absorption.

The most commonly used technology for $NO_X$ emission control is SCR. NSCR, which also controls $N_2O$, was more common before the 1970s; however since then, SCR technology has been widely applied because of its cost effectiveness. While NSCR is less common, it is still used by as many as 20% of existing process units. Therefore, $N_2O$ is being abated currently at as many as 12 process units. As a result, the opportunities to further destroy $N_2O$ from these facilities are limited.

## A.4 Current Industry Practice for Using $N_2O$ Emission Controls

Installation of $N_2O$ emission controls is not standard industry practice anywhere globally and it has only been recently that the technologies were developed (i.e. since the onset of compliance and voluntary GHG markets). At the time of protocol development, CDM methodologies have been approved for both secondary (AM0034) and tertiary abatement (AM0028). At that time, 42 projects using secondary abatement (following AM0034) were being implemented outside of North America with estimated reductions of 9,942,836 $tCO_2e$/year. Fifteen tertiary abatement projects were being implemented outside North America using AM0028 with estimated reductions of 7,415,849 $tCO_2e$/year. Since 2010, when the Reserve completed development of its Nitric Acid Plant Project Protocol, Version 1.0, the CDM methodologies have undergone a number of revisions. Since May 31, 2013, the CDM methodology which address $N_2O$ abatement from nitric acid production has been ACM0019 (version 2.0), which is the CDM methodology upon which the NAPPP Version 2.1 protocol update is based.

The EPA database does not cover use of dedicated $N_2O$ emission control technologies (NSCR is reported because of its use as a $NO_X$ control technology). However, according to the Terra Industries representative and others on the workgroup, there are only two $N_2O$ abatement units operational in the United States. Both are secondary abatement units operated by Terra Industries. They have been installed at two process units in different locations to demonstrate the efficacy of the technology and to demonstrate positive action towards reducing GHG emissions.

## A.5 Baseline Scenarios for $NO_X$ Emission Controls and $N_2O$ Emissions

The most plausible baseline scenario for nitric acid plants with regard to $NO_X$ emission controls is for the continued use of SCR technology, which has minimal impact on $N_2O$ emissions. This includes at existing, upgraded, relocated, or restarted plants. SCR technology enables compliance with existing $NO_X$ regulations, is cost effective compared to other $NO_X$ control technologies, and is considered the industry standard. Historically, there was a transition from using the older, now outdated NSCR technology to SCR and there is little chance for reversing that trend under business as usual conditions.

Nitric acid plants currently operating with NSCR are likely to continue using this technology unless they undergo a significant plant upgrade. In cases where NSCR is replaced with SCR, there are implications for $N_2O$ emissions (i.e. a shift from NSCR to SCR would increase $N_2O$ emissions in the baseline scenario). In addition, the opportunity for additional $N_2O$ emissions reductions from plants operating NSCR are relatively small compared to plants operating SCR or no $NO_X$ controls.

There are believed to be very few process units operating without some form of $NO_X$ emission control and in the event that emission controls would need to be added to these process units, it is probable that SCR would be the chosen technology.

## A.6 Common Practice for Nitric Acid Production Levels

If a facility produces $HNO_3$ in excess of what would be produced under business as usual, a case can be made that more $N_2O$ is generated and controlled by the abatement technology than would otherwise, resulting in emission reductions than should not be considered additional. Industry representatives on the stakeholder workgroup for this protocol contend that the economics of $HNO_3$ production make this scenario implausible as production levels are driven entirely by natural gas prices and market demand for raw and upgraded nitric acid products, and the cost to produce $HNO_3$ exceeds the potential revenue from carbon credits, based on current market conditions. (According to the workgroup, the current cost to produce one metric ton of 100% $HNO_3$ is approximately $90, with the corresponding potential to reduce about 2.5 metric tons of $CO_2$e.)

# Appendix B Emission Factor Tables

**Table B.1.** Default Baseline Emission Factor for New Production in Excess of $HNO_{3,MAX,scaled}$ ($EF_{New}$) and Tertiary Projects Operating Outside AOC, as needed ($EF_{IPCC}$)

| Year | Emission Factor ($tN_2O/tHNO_3$) |
|---|---|
| 2014 | 0.0035 |
| 2015 | 0.0034 |
| 2016 | 0.0032 |
| 2017 | 0.0030 |
| 2018 | 0.0028 |
| 2019 | 0.0027 |
| 2020 | 0.0025 |
| After 2020 | 0.0025 |

Source: Clean Development Mechanism (CDM) ACM0019, Version 02.0.0, EB73.

# Nitrogen Management Project Protocol V1.1

Protocol Summary

CLIMATE ACTION RESERVE

## Project Definition

A reduction in the annual rate of synthetic nitrogen fertilizer applied (N rate) compared to recent application rates at the project site. Implementing additional nitrogen best management practices helps growers to enable N rate reductions, without going below crop nitrogen demand. The project activity is currently applicable to corn cropping systems only and can be located on one field or multiple fields participating as an aggregate project.

## Project Eligibility Requirements

**Location:** North Central Region of the United States. Region includes Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Mississippi, Nebraska, North Dakota, Ohio, South Dakota and Wisconsin. Within those states, only counties with mean annual precipitation between 600 and 1200 mm annually are eligible (see map in protocol), and no projects may be implemented on organic soils (e.g. histosols).

**Eligible Cropping Systems:** Rainfed continuous corn or corn rotations, but only corn crop years are creditable. All types of fertilizer (both synthetic and organic) may be applied, but only reductions in synthetic N rate are creditable. Emergency irrigation is permissible in case of severe drought, but fields may not be regularly irrigated. The project area may include both tile-drained and non-tile-drained fields.

**Start Date:** The first day of a new cultivation cycle (i.e. the first day after completion of the previous harvest) during which an N rate reduction project is implemented. Projects with start dates after June 27, 2010 may be submitted at any time until June 27, 2013.

**Crediting Period:** Five eligible (corn) crop years, over a period of up to 10 years. Crop years may be non-consecutive with a multi-crop rotation, but reporting must be continuous. The crediting period is renewable one time.

**Performance Standard Test:** The grower must demonstrate that the project field's RTA (i.e. ratio of N removed by crop to N applied) exceeds the average state RTA. The field-level RTA is calculated at the end of the cultivation cycle for each eligible crop year using total annual N rate for that year and average historic yield. Therefore, prior to the growing season, growers are encouraged to determine the maximum N rate at which they will meet the RTA threshold.

**Legal Requirement Test:** Project must exceed any N rate reductions that would have occurred as a result of compliance with federal, state or local regulations. If a Nutrient Management Plan is required by law, the field may not be eligible (see protocol for further details). Project developer or aggregator must sign the Attestation of Voluntary Implementation for each verification period.

**Ecosystem Services Payment Stacking:** Payment stacking is permissible, but only under certain circumstances. Fields receiving payments from the Natural Resources Conservation Service (NRCS) for practices other than N rate reductions under Conservation Practice Standard (CPS) 590 or any other CPS are fully eligible. Project fields under contract to receive CPS 590 payments are not eligible if the contract with NRCS was signed prior to the project start date or submittal to the Reserve. However, fields receiving CPS 590 payments are eligible if the project is submitted to the Reserve concurrent to pursuing CPS 590 payments. Project fields stacking NRCS payments are only eligible to receive CRTs for the portion of the project not funded by public dollars.

**Regulatory Compliance:** Project must be in compliance with all relevant federal, state, and local regulations. Project developer or aggregator must sign the Attestation of Regulatory Compliance for each verification period.

**Reporting and Verification Schedule:** Project must report annually. Project must undergo verification for each eligible crop year, which may be non-consecutive for multi-crop rotations. Single-field projects are provided additional flexible reporting and verification options. Risk-based and random sampling is used for verification of aggregate projects.

## Project Is Ineligible If:

- Located on lands with no previous cropping history
- Located on lands designated as highly erodible and/or wetlands
- Management records from the past five years (or past three years of eligible crop in a rotation) are not available to set the project baseline
- Frequency of corn crop increases due to the project

601 W. 5th Street, Suite 650
Los Angeles, California 90071
www.climateactionreserve.org
T: (213) 891 1444

*Important Note: This is a summary of the protocol. Please read the full protocol for a complete description of project requirements.*

CLIMATE
ACTION
RESERVE

# Nitrogen Management Project Protocol
# Summary of Changes from Version 1.0 to Version 1.1

January 17, 2013

- Added clarifying language to Section 3.3 on the ability to generate CRTs only in eligible crop years.
- Corrected contradictory text on Farm Bill conservation compliance provisions to clarify when highly erodible lands (HEL) and wetlands can be eligible under this protocol. (Section 3.4)
- Added Table 3.2 “Payment Stacking Scenarios” to provide additional clarity on project eligibility and payment stacking. (Section 3.5.3.2)
- Added Figure 4.1 “General Illustration of the GHG Assessment Boundary” to provide additional clarity. (Section 4)
- Revised “Applicability Conditions” based on technical revisions to Section 5. Specifically, allow for tile drains in the project (if also present in the baseline) and added clarifying language, particularly with regard to emergency irrigation. (Section 5.1)
- Added the term “baseline look-back period” to the glossary and used this term to clarify language throughout the protocol. (Section 5.2.1 and 9)
- Changed quantification of LVRO emissions to use the reporting period’s $Frac_{LEACH}$ value for both baseline and project, and to include a default $Frac_{LEACH}$ for tile drains. (Section 5.3.2)
- Provided additional guidance on calculating the project-specific $Frac_{LEACH}$. (Section 5.3.2 and the newly added Appendix E)
- Clarified how to properly take the average for baseline $N_2O$ emissions, and whether N rates were annual or average values throughout Section 5. (Section 5.2.1, 5.3.1, and 5.3.2)
- Revised structural uncertainty methodology (Equation 5.15) to incorporate a change the Reserve previously said would be made in the Staff Response to Public Comments (Version 1.0). Specifically, the revision allows for structural uncertainty to be scaled based on the number of fields enrolled at the program-level, instead of at the aggregate-level, by introducing the Uncertainty Adjustment Factor (UAF), which will be published on the Reserve website. (Section 5.3.4)
- Added additional parameters to Table 6.1.
- Updated reporting requirements to note whether HEL or wetlands are present in reports and updated record keeping requirements to include documentation of USDA NRCS determinations. (Section 7.2 and 7.3)
- Updated verification requirements to include verification of HEL, wetlands, and tile drains, and clarified text. (Table 8.1, 8.2, and 8.3)