GE AES Greenhouse Gas Services

Methodology for Landfill Gas Methane Capture and Destruction Projects

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NOTES TO USERS:

Please check that you are using the most current version of this Methodology.

GE AES Greenhouse Gas Services will review the Methodology on an annual basis, and may make non-substantive edits from time to time as appropriate.

This Methodology contains procedures to quantify emissions reductions from capture and destruction of methane. Sections related to displacement credits are under separate general methodologies.

For Information, Comments or Questions – Please Send Electronic Mail to:
adam.penque@ghgs.com

Content

1 Summary and Applicability of Methodology

This document establishes a methodology for the quantification of greenhouse gas (GHG) emission reductions, or credits from eligible landfills. These GHG credits are based on metric tonnes of CO_2e, a standardized measure of GHG measurement. This protocol will be used by project developers to bring GHG credits from eligible landfills in the United States and in other locations, to market and make the reductions relevant and transferable to other major GHG markets.

1.1 Methodology Description

1.1.1 Purpose and Objectives

Concern over climate change due to increasing levels of GHG's in the atmosphere has led to evaluation of different methods to reduce GHG emissions. According to the U.S. Environmental Protection Agency (USEPA)[1] , methane from municipal solid waste landfills is the largest source of human-made methane in the U.S., contributing approximately 25% to the total amount of methane emitted. Landfill gas typically contains 50% methane and 50% carbon dioxide and other trace compounds. Given that the Intergovernmental Panel on Climate Change (IPCC) estimates that methane has a global warming potential (GWP) of 21-25 times that of carbon dioxide, the reduction of methane emission can provide significant reduction of total GHG emissions[2,3,4].

The collection and control of landfill gas (LFG) in the U.S. is a proven practice and is required for many landfills by the New Source Performance Standards (NSPS) under 40 CFR 60 Subpart WWW. These landfills are required to collect and control the landfill gas via flaring, use in a combustion device such as an engine or boiler, or treat the landfill gas to remove particulate and moisture before using the treated LFG as a fuel. Landfills that are required to collect and control LFG under the NSPS are not considered to be eligible candidates for GHG credits since methane control is achieved through the required incineration of non-methane organic compounds contained in the LFG. Therefore, methane and GHG emission reductions from NSPS-regulated facilities operating under regulatory requirements are not voluntary. However, many small and medium sized landfills are not required to collect and control LFG. In addition, facilities can install LFG collection systems and collect gas prior to the date or stage at which collection requirements apply (pre-regulation – see Section 2.1, below – during the 30 months following the date on which the NMOC emissions from the landfill exceed 50 Mg/year). Voluntary reductions of methane and GHG's credits from these sites and under these circumstances could be monetized through GHG markets.

Additionally, the use of LFG to generate electricity or provide thermal energy can displace the use of fossil fuels. The displacement of such fossil fuels also provides a quantifiable level of GHG reductions.

[1] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004. U.S.E.P.A. #430-R-06-002
[2] IPCC Second Assessment Report: Climate Change 1996
[3] IPCC Third Assessment Report: 2001
[4] IPCC Fourth Assessment Report: 2007

Since voluntary reductions of methane from LFG combustion or energy generation using LFG can be monetized in GHG markets, a methodology is necessary to determine eligible landfills, measure the amount of methane destroyed, energy produced, keep records, and validate these GHG credits. This protocol must have sufficient environmental and scientific integrity to provide accurate and verifiable emission reduction measurements.

1.1.2 Projects that can utilize this methodology

Before GHG credits can be developed from a methane destruction project at a landfill, each landfill must be evaluated to determine if emission reductions are considered to be voluntary and not the result of any Federal, State, or Local regulatory requirements and whether the gas collection and control system installation date falls within the scope of the Standard of Practice. While many regulatory programs for landfills require equipment and processes similar to those used to achieve voluntary reductions and essentially achieve the same level of GHG reductions, the Standard of Practice standard does not consider GHG reductions achieved under a regulatory framework to meet the voluntary criteria for this protocol. Essentially, qualifying GHG emission reduction activities at landfills must represent reductions that are achieved outside of those achieved by existing regulatory drivers.

This methodology also contemplates the operation of energy projects utilizing methane captured under this methodology. *GHG reductions attributable to displaced natural gas or grid electricity consumption are addressed in this methodology but require the GHGS methodology titled Quantification Methodology for Displacement Projects.* These projects can be based on the use of LFG collected voluntarily or LFG required for collection under Federal, State, or Local regulatory requirements. Since these regulations address the destruction of non-methane organic compounds, they do not prescribe that landfills use energy projects to achieve compliance. Therefore, the Standard of Practice will consider the GHG reductions achieved via the displacement of fossil fuels used for electrical or thermal energy generation.

Operational activities for projects or activities creating credits must have commenced after January 1, 2000, and credits-generating activity will only be certifiable for activity started after January 21, 2002. Additionally, demonstration of ownership rights of the LFG must be demonstrated. For most recently developed LFG projects in operation, LFG rights are clearly outlined in any contractual agreement between the landfill, end-users, and/or third-parties. In some cases, landfills may enter into contracts with other parties and sell the rights to the LFG without actually having an LFG collection and control project in place.

1.1.3 Relevant GHG Methodologies and Standards

The development of this methodology included review of several different existing or proposed GHG methodologies in order to evaluate the various aspects of these methodologies that meet the overall principles and requirements of the Standard of Practice. This evaluation included the review of the following methodologies:

1. Standard of Practice for GHG Credits

2. Clean Development Mechanism, Annex 13, "Methodological tool to determine project emissions from flaring gases containing methane."
3. U.S. EPA Climate Leaders, Draft Offset Protocol, Project Type: Landfill Methane Collection and Combustion, October 2006.
4. Protocol for Measuring and Verifying Greenhouse Gas Reductions from Landfills, Chicago Climate Exchange.
5. ISO 14064-2:2006 GHG Project Standard
6. WRI/WBCSD GHG Projects Protocol
7. Clean Development Mechanism. Approved consolidated baseline methodology ACM0001. "Consolidated baseline and monitoring methodology for landfill gas project activities."

Overall, this methodology incorporates similar elements for determining GHG credits from landfill gas projects such as measuring landfill gas flow to a combustion device and monitoring combustion device operation. This approached was adopted in order to develop a methodology that will facilitate a voluntary trading market but provide sufficient documentation to ensure the credibility of the GHG credits delivered to the market.

1.1.4 Relevant Technical Codes, Standards, and Guidelines

Existing U.S. regulations that address landfill gas and NO_x/SO_2 emission trading programs were reviewed and considered in the development of this methodology. These regulations included 40 CFR 60 Subpart WWW (Landfill NSPS) and 40 CFR Part 75 (Continuous Emission Monitoring procedures to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program, including gas and oil-fired turbines). Some of the monitoring provisions outlined in the landfill NSPS were incorporated as landfill owners and operators will already be familiar with these requirements, in addition to many of the equipment suppliers that work with these sources. Additionally, aspects of the reduced monitoring options outlined in 40 CFR 75 that are applicable to gas and oil-fired turbines were incorporated into this methodology. Since EPA has already evaluated and approved some of these monitoring methodologies for existing cap-and-trade programs, the credibility of these requirements has already been established. Furthermore, vendors of the data acquisition and handling systems that would be used to calculate emission reductions are already familiar with many of the requirements and algorithms contained in this methodology. This should result in reduced cost in designing and operating data acquisition and handling systems needed to manage the data for this methodology.

1.1.5 Relevant Legal Authorities and Regulations

1.1.5.1 Existing Regulatory Programs for Landfills

Landfills are regulated by several EPA standards regarding solid waste disposal (Subtitle D requirements) and air emissions, along with many state and local environmental and zoning requirements. These regulations must be observed by landfill owners and operators and nothing in this protocol absolves landfill owners and operators from observing these regulations.

Emission control requirements for landfills exist under several different regulatory programs. The most common regulatory program that establishes an emission control requirement for landfills is the New Source Performance Standard (NSPS) codified in 40 CFR 60 Subpart WWW. Under the NSPS, landfills that have a design capacity that exceeds 2.5 million cubic meters and 2.5 million megagrams and commenced construction, reconstruction, or modification after May 30, 2007 are required to evaluate their non-methane organic compound (NMOC) emission rate. If, based on the evaluation criteria outlined in the NSPS, the NMOC emission from the landfill exceed 50 Mg/year, then the landfill has 30 months to install a landfill gas collection and control system. For landfills that commenced construction, reconstruction, or modification before May 30, 1991, the Emission Guidelines (EG) codified in 40 CFR 60 Subpart Cc outlines similar applicability and control requirements as the NSPS. EPA also promulgated a National Emission Standard for Hazardous Air Pollutants (NESHAP) for municipal solid waste landfills on January 13, 2003 (see 40 CFR 63 subpart AAAA). This regulation requires gas collection and controls systems based on the requirements in the NSPS, but may result in different compliance schedules based on certain landfill characteristics.

For landfills considered for developing GHG credits, documentation of regulatory applicability status is required by this protocol to demonstrate that any gas collection and control activities are the result of voluntary actions and not in response to regulatory requirements. In some cases, the entire gas collection and control system may be required by a specific regulation. However, some sections of a gas collection and control system may be voluntary as a landfill may install these systems before a specific compliance date. For the purposes of this protocol, installation of a collection and control system in advance of a known compliance date can result in eligible GHG credits. However, once the compliance date is reached, GHG credits are no longer eligible. (see Section 2 of this methodology for eligibility criteria that must be provided with project documentation)

1.1.5.2 Ownership of Gas Rights and Environmental Attributes

LFG projects in the U.S. include contractual agreements between the landfill and developers, end-users, and other third-parties. These contractual agreements outline the ownership of the LFG and any associated environmental attributes from the use of the LFG. Environmental attributes include the potential GHG credits created from the combustion of unregulated LFG and the generation of "green" electricity when the LFG is used to power electrical generating systems. Sometimes, these LFG agreements are enacted even before any LFG collection systems have been constructed at landfills. For the purposes of the Standard of Practice, documentation of LFG ownership must be provided to demonstrate that the entity bringing the GHG credits to market have legal ownership of the LFG and that the GHG credits will not be used in other markets. For some LFG projects, two mechanisms exist for GHG credits. The first is through the voluntary combustion of methane, and the second is from the offset of GHG emissions from fossil fuels combustion when the LFG is used to generate electric or thermal energy (e.g., boilers, kilns, process heaters). The Standard of Practice will allow a project to bring GHG credits based on the destruction of methane to this market, and GHG credits resulting from the displacement of fossil fuel use or alternative energy generation via the use of LFG to another market in accordance with the *GHGS methodology titled Quantification Methodology for*

Displacement Projects. Documentation of the ownership and fate of these attributes must be clearly described and provided to demonstrate eligibility for GHG credits.

For example: Utilities in some states are required to generate a percentage of their overall electrical supply from alternative energy sources, such as landfill gas based electrical generation activities. In such an area, demand for green electricity may result in a premium value for electricity generated by an LFG energy project. In such a case, the project developer may be able to receive greater income by selling green energy on the grid versus selling the GHG credits resulting from the displacement of fossil fuels under the Standard of Practice. However, the project developer would still look to sell GHG credits from the destruction of methane under the Standard of Practice. Such a scenario is allowed under this methodology. This approach is allowed, provided, that the project developer does not violate the principle of uniqueness as defined in the Standard of Practice.

2 Eligibility criteria for each Scenario in this Methodology

The following table provides a summary of the factors used to evaluate the eligibility of GHG credits projects at landfills under the Standard of Practice.

Table 1: Eligibility Criteria for Landfill Gas Projects

Subject	Eligibility Criteria
Commencement of methane destruction.	• Operational activities for projects or activities creating credits must have commenced after January 1, 2000, and credits-generating activity will only be certifiable for activity started after January 21, 2002.
Landfill gas collection and control mandated by any regulation.	• LFG collection and control system must not be required under NSPS, EG, or NESHAP programs for project to be eligible. • If landfill is, or will be, subject to LFG control requirements under NSPS, EG, or NESHAP regulations and plans to install LFG collection and control systems in advance of regulatory requirements, the site must provide information demonstrating voluntary installation and anticipated regulatory compliance date.
Ownership of landfill gas and any green or environmental attributes of the landfill gas.	• Must demonstrate ownership of LFG • Must certify that GHG credits offered under the Standard of Practice from the collection and control of LFG are not used in other GHG markets. • If end-use application of LFG (e.g., electrical generation) is participating in green or alternative energy market, project must demonstrate that credits offered under the Standard of Practice are not participating in another program.

In addition, the following items must be provided and maintained in order to demonstrate regulatory status for each landfill:

- Section of landfill permit issued by state/local solid waste authority that indicates design capacity of the landfill. Design capacity must be provided in cubic meters and in megagrams.
- Documentation of installation date of gas collection and control system considered for GHG credits

- For landfills with design capacity greater than 2.5 million cubic meters and 2.5 million megagrams, provide a summary of the most recent NMOC emission rate calculations conducted according to 60.754.
- For landfills with design capacity greater than 2.5 million cubic meters and 2.5 million megagrams, if the most recent NMOC emission rate calculation is greater than 50 megagrams per year, provide the date of the most recent NMOC calculation and the anticipated date of required gas collection and control system operation under the NSPS, EG, or NESHAP.
- For landfills that are considered to be bioreactors as defined in 40 CFR 63.1990 and have a design capacity greater than 2.5 million cubic meters and 2.5 million megagrams, provide the expected compliance date as determined by 40 CFR 63.1947.
- If a landfill is already subject to the NSPS, EG, or NESHAP emission control standard and GHG credits are planned from early gas collection control system installation in an area, cell, or group of cells, provide initial date of waste placement for the specific section to demonstrate that the waste has been in place less that 2 years if the area is closed or at final grade or less than 5 years if the area is still active. Also provide the expected date that a gas collection system is required for that area, cell, or group of cells.

3 Methodology Structure

The following table presents the general structure of the methodology and refers the reader to the specific section where each scenario is described and procedures for quantification, monitoring and data management that the project developer may select.

In addition to the default scenarios, this methodology includes a section for determining the appropriate baseline scenario, as well as the documentation and reporting requirements

Table 2: Methodology Structure

Structure	Relevant Section
Scenario Description	Section 5.1
Identification of Sources, Sinks & Reservoirs	Section 5.2
Selecting relevant SSRs for Quantification	Section 5.3
Determining the baseline scenario	Section 6
Quantification	Section 7
Simple Monitoring	Section 8.1
Advance Monitoring	Section 8.2
QA/QC Data Management Procedures	Section 9
Emission Reduction Quantification	Section 10
Documentation and Reporting	Section 11

This protocol establishes two approaches in quantifying GHG credits resulting from the destruction of methane from eligible landfills. The simplified approach prescribes less stringent testing and monitoring provisions, but uses more conservative assumptions in the calculation of GHG credits. Alternatively, the more advanced approach requires a higher level (and cost) of testing and monitoring, but may allow eligible landfills to deliver greater GHG credits to the market. These two options are allowed in order to provide greater flexibility for project developers that wish to bring GHG credits to the market given that it is a voluntary market at this time. In the development of the simple and advanced approached provided in this methodology, the Standard of Practice has balanced the level of detail in monitoring requirements with the degree of conservativeness in various calculations to ensure that GHG credits delivered under each approach are equivalent from the standpoint of quantity and credibility.

4 Terms and Definitions

4.1 Emission Guidelines (EG)

Guidelines for State regulatory plans that have been developed by the U.S. EPA. For landfills, emission guidelines are codified in 40 CFR 60 Subpart Cc.

4.2 Landfill gas (LFG)

The gaseous by-product of the decomposition of municipal solid waste. Typically, landfill gas contains methane, carbon dioxide, and various trace organic and inert gases.

4.3 Municipal Solid Waste (MSW) Landfills

An entire disposal facility where household waste is placed in or on land. An MSW landfill may also receive other types of RCRA Subtitle D wastes (see 40 CFR 257.2) such as commercial solid waste, non-hazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste.

4.4 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Federal emission control standards codified in 40 CFR 63. Subpart AAAA of Part 63 prescribes emission limitations for municipal solid waste landfills.

4.5 Non-methane organic compounds (NMOC)

Non-methane organic compounds as measured according to the provisions of 40 CFR 60.754.

4.6 New Source Performance Standards (NSPS)

Federal emission control standards codified in 40 CFR 60. Subpart WWW of Part 60 prescribes emission limitations for municipal solid waste landfills.

4.7 Resource Conservation and Recovery Act (RCRA)

Federal legislation under which solid and hazardous waste disposal facilities are regulated

5 Description of Scenarios and Identification of SSRs

5.1 Descriptions of Scenarios

Generally, LFG contains around 50% methane, 50% carbon dioxide, and various other compounds such as oxygen, nitrogen, and NMOC's. However, methane content can vary from minimal amounts up to 60% in some cases. Given the significant amount of methane in LFG, beneficial use of LFG has been an economically viable option for many years. Additionally, the heat content in LFG provided by methane typically provides enough energy to effectively destroy the NMOC's, the regulated pollutant under the NSPS and EG requirements. All emission control standards for landfills provide options for destroying NMOC's (and methane) through the use of flares and other combustion equipment such as boilers, engine, turbines to name a few. Since LFG can burn without assistance from other fuels, a controlled combustion environment can provide close to 100% destruction of all organic compounds in the LFG, including methane.

For the purposes of this standard, projects where methane destruction is achieved through combustion devices are eligible GHG credits. This can occur on-site via use of a flare, engine, turbine, boiler, or other combustion device, through a dedicated LFG pipeline to a remote combustion end-use of LFG, or through injection of LFG into a regulated natural gas pipeline system. Additionally, electrical or thermal energy generation using LFG is a project scenario under this standard and the eligible GHG credits would be based on the amount of energy generated and the amount of GHG credits achieved by displacement of fossil fuel use through this generation.

All GHG credit projects can choose between a simple or advanced quantification and monitoring approach. Under the simple approach, the standard provides default methane combustion efficiencies as shown in Table 3.

These default methane combustion efficiencies are applicable as long as the device can be demonstrated to be in operation and combustion is taking place. For open and enclosed flaring systems, a minimum combustion temperature of $500^{O}C$ must be demonstrated for evidence of combustion[5]. Project developers do have the option of proposing alternative monitoring plans for flares, however, these alternative approaches are not automatically approved and GHGS retains discretion for case-by-case approval. Projects that control methane in LFG using utilization projects (e.g., boilers, engines, turbines, natural gas pipeline injection), can use operational parameters to demonstrate operation. The use of default combustion efficiencies are acceptable for all credit projects (excluding injection into natural gas pipeline systems) that use LFG with a heat value of 300 Btu/standard cubic foot or greater. If an eligible project is at a landfill where the landfill gas has a heat value of less than 300 Btu/standard cubic foot, only the advanced method for determining combustion efficiency can be used.

[5] If $500^{O}C$ cannot be demonstrated due to flare design and thermocouple location an alternative minimum temperature can be established provided that the temperature is deemed sufficient to evidence presence of flame during flare operation.

Table 4 provides a brief description of the landfill gas project scenarios presently in use or anticipated in the future; however, this list is not to be considered exhaustive as new scenarios may be developed.

Table 3: Default Methane Combustion Efficiencies

Combustion Technology	Combustion Efficiency	Notes
Open Flare	96%[6,7] 50[8]%	96% can be used if flare is operated according to 40 CFR 60.18, otherwise 50% should be used.
Enclosed Flares where LFG is burned in an enclosure that includes a burner and damper system for combustion control.	98%[9] 90%[7]	98% can be used if the enclosed flare achieves a minimum retention time of 0.3 seconds[10], otherwise 90% should be used.
Engine, Turbine, Boiler, other combustion device	98%[7]	
Regulated Natural Gas Pipeline*	98.1%[11]	

*The more conservative efficiency factor of 98.1% is used for injection into a regulated natural gas pipeline.

6 Flare Efficiency Study, EPA-600/2-83-052. U.S. Environmental Protection Agency, Cincinnati, OH. July, 1983.

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

8 Clean Development Mechanism – Executive Board. Annex 13: Methodological "Tool to determine project emissions from flaring gases containing methane"

9 Current MSW Industry Position and State of the Practice on LFG Destruction Efficiency in Flares, Turbines, and Engines. Solid Waste Industry For Climate Solutions/SCS Engineers. July 2007.

10 Pennsylvania Department of Environmental Protection. Best Available Technology Criteria for Municipal Waste Landfills. 25 PA 127.12(a)(5)

11 The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas combustion 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 grid 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 given as 0 to 87,000kgCH4/PJ, which is 0.4%, or in industrial plants and power station the losses are 0 to 175,000kg/CH4/PJ, which is 0.8%. These leakage estimates are additive. Eff_{GAS} 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.

Table 4: Project Scenarios

Potential Scenarios	Description
1	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed using a flare.
2	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed through utilization to produce electricity.
3	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed through utilization to produce thermal energy (e.g., boiler, kiln, process heater).
4	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed via injection into a regulated natural gas pipeline system and ultimately burned in a combustion device.
5	Electricity is generated using LFG (conventional fuels for the baseline scenario) and displacing the use of fossil fuels in electrical production activities.
6	Thermal energy is generated using LFG (natural gas for the baseline scenarios) and displacing the use of fossil fuels

GHG reductions attributable to displaced natural gas or grid electricity consumption are addressed in this methodology but require the GHGS methodology titled Quantification Methodology for Displacement Projects.

5.2 Identifying the Sources, Sinks and Reservoirs (SSRs) Relevant to the Scenarios

In accounting for emissions, removals and storage relevant to the scenario (whether project or baseline) the ISO 14064-2:2006 GHG Project Standard refers to emissions by sources, removals by sinks and storage in reservoirs (SSRs). The informative annex of ISO 14064-2:2006 describes the relationship of this terminology with CDM. "Controlled SSRs" are physical units/processes owned/controlled by the project developer. "Related SSRs" are physical units/processes not owned/controlled by the project developer, but are related to the project by physical flows of material or energy into or out of the project (e.g. the electricity grid is related because the project either consumes electricity from the grid, causing emissions "offsite", or the project provides electricity to the grid, causing emissions "onsite"). "Affected SSRs" are physical units/processes neither owned/controlled by the project developer nor "related" to the project by physical flows, rather, affected SSRs are affected by economic changes resulting from the project activity. Affected SSRs are equivalent to "leakage" used in CDM.

5.2.1 Controlled and Related SSRs

The following figure illustrates the controlled and related SSRs relevant for landfill gas scenarios. Table 5 indicates the SSRs that are present in the selected scenario and that are relevant for quantification.

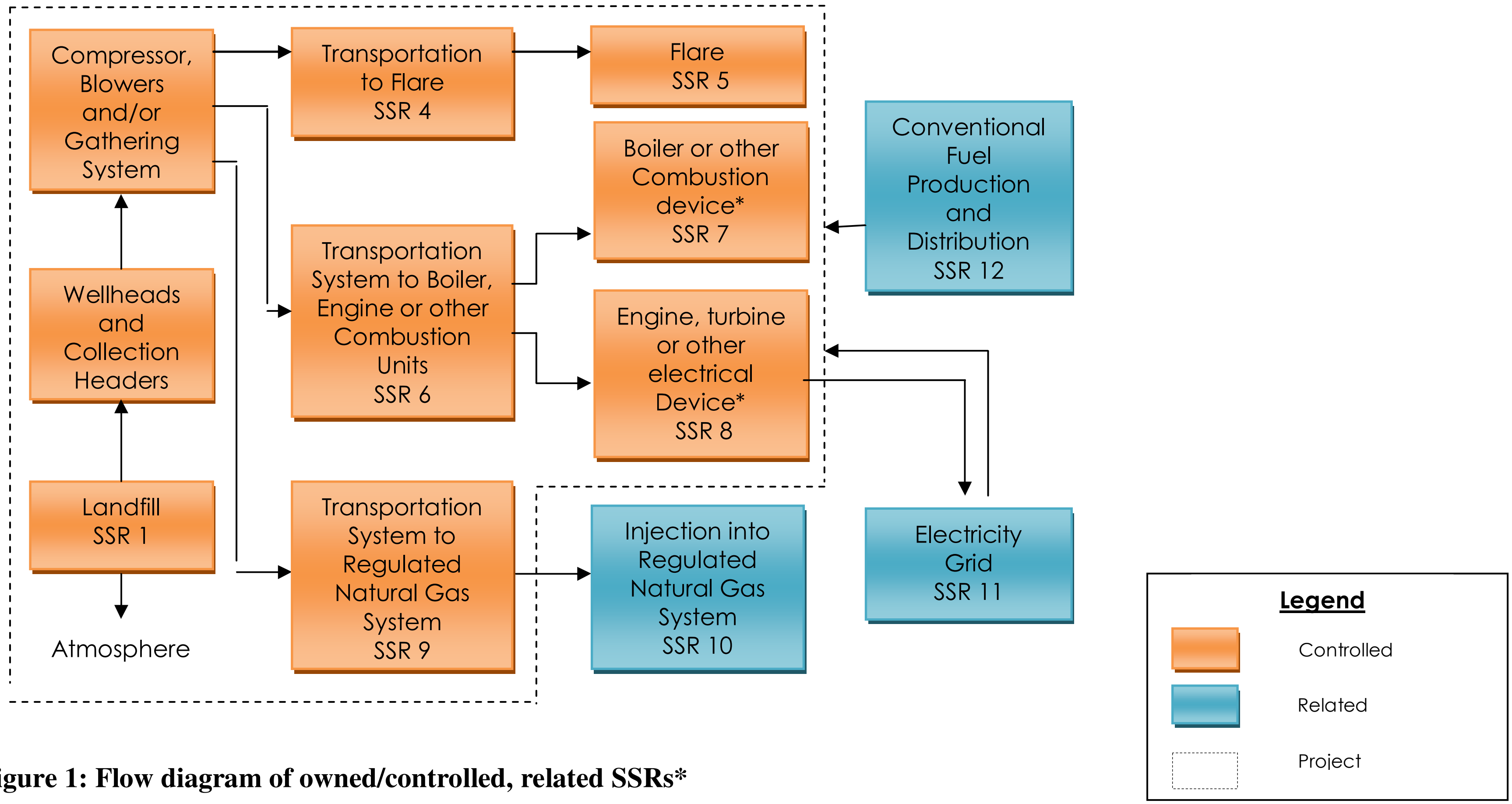

Figure 1: Flow diagram of owned/controlled, related SSRs*

* SSR 7 and SSR 8 can be either controlled or related depending on the project circumstances (see definition of controlled versus related SSRs in the ISO 14064-1 Standard.

Table 5: SSR present in the Selected Scenario that are Relevant for Quantification

Capture/Displacement Scenarios		Sources, Sinks and Reservoirs											
		1 Landfill	2 Wellheads and collection headers	3 Compressors, blowers/and/or gathering system	4 Transportation to flare	5 Combustion in Flare	6 Transportation to boiler, engine, or other combustion device	7 Boiler or other combustion device	8 Engine, turbine or other electrical device operation	9 Transportation to natural gas pipeline	10 Natural gas pipeline system	11 Electricity Grid	12 Conventional fuel production & distribution
1	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed using a flare.			P		P						P	P
2	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed through utilization to produce electricity.			P					P			P	P
3	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed through utilization to produce thermal energy (e.g., boiler, kiln, process heater).			P				P				P	P
4	Methane from a landfill, or area of a landfill, not subject to any emission control standards is captured and destroyed via injection into a regulated natural gas and ultimately burned in a combustion device			P							P	P	
5	Electricity is generated using LFG and displacing the use of fossil fuels in regional electrical production activities.								B			X	B
6	Thermal energy is generated using LFG and displacing the use of natural gas.							B					B

Note:

- SSRs marked with an X can be relevant for both the project and the baseline
- SSRs marked with a P can be relevant only for project
- SSRs marked with a B can be relevant only for baseline

5.2.2 Affected SSRs (Leakage)

No routes for leakage have been identified for landfill gas projects.

5.3 Selecting GHG SSRs for monitoring or estimating GHG emissions

Whereas Section 5.2 identifies SSRs relevant to the scenario, this section identifies SSRs relevant to the quantification of emissions. SSRs relevant to the scenario may be excluded from the SSRs relevant for to the quantification of emissions for justified reasons without compromising the credibility of the emission reductions.

For the purposes of this standard, projects that deliver GHG credits based on the control of methane in unregulated LFG streams, the project boundary includes the infrastructure that collects and transports the LFG from the landfill to the combustion source, and the combustion source itself. For projects that deliver GHG credits based on electrical generation and the offset of electrical generation via traditional fuels, the project boundary includes the electrical generating unit. For projects that deliver GHG credits based on thermal energy generation and the offset of thermal energy generation via traditional fuels, the project boundary includes the thermal energy generation unit.

Table 7: Identified SSRs for all Scenarios

SSR Number	Source	Gas	Included/ Excluded	Justification/Explanation
1	Landfill	CH_4	Excluded	· Main emission source of methane from landfills
2	Wellheads and collection headers	CH_4	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
		CO_2	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
3	Emissions resulting from energy used by compressors, blowers, and/or gathering system	CO_2	Included	· Energy consumption from equipment used to drain, compress, blow and gather LFG
		CH_4	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
		N_2O	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
4	Fugitive emissions from transportation system to flare	CH_4	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
5	Emissions resulting from combustion during flaring	CO_2	Excluded	· CO_2 emissions from the combustion of LFG represent short-cycle carbon emissions and do not result in an overall increase in GHG emissions (biogenic emissions)
		CH_4	Included	· Based on efficiency of combustion device.
6	Fugitive emissions	CH_4	Excluded	· Excluded for simplification. This emission source is

	from Transportation System to Boiler, Engine or other Combustion device			assumed to be very small.
7	Boiler or other Combustion device	CO_2	Excluded	· CO_2 emissions from the combustion of LFG represent short-cycle carbon emissions and do not result in an overall increase in GHG emissions (biogenic emissions)
		CH_4	Included	· Based on efficiency of combustion device.
		N_2O	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
8	Engine, turbine or other electrical device	CO_2	Excluded	· CO_2 emissions from the combustion of LFG represent short-cycle carbon emissions and do not result in an overall increase in GHG emissions (biogenic emissions)
		CH_4	Included	· Based on efficiency of combustion device.
		N_2O	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
9	Transportation System to regulated natural gas pipeline system	CH_4	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
10	Regulated natural gas pipeline system	CO_2	Excluded	· CO_2 emissions from the combustion of LFG represent short-cycle carbon emissions and do not result in an overall increase in GHG emissions (biogenic emissions)
		CH_4	Included	· Based on efficiency of combustion device.
		N_2O	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
11	Electricity Grid	CO_2	Included	· CO_2e emission rate (ton/MWh) from Emissions regional power generation and distribution system.
		CH_4	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
		N_2O	Excluded	· Excluded for simplification. This emission source is assumed to be very small.
12	Conventional fuel production & distribution	CO_2	Excluded	· Excluded because project will require less production of fossil fuel than baseline scenario; therefore, conservative to exclude.

6 Determining the Baseline Scenario

6.1 Considerations for Selecting the Baseline Scenario

6.1.1 Project Accounting for Destruction of Methane Only

The Standard of Practice has decided that no baseline emission calculations are required for eligible LFG credit projects that only want to receive credits for destruction of methane. For methane generation from landfills, to determine a baseline GHG emission level, accurate measurement of uncontrolled LFG would need to be ascertained. Currently, no widely accepted method, other than mathematical modeling of landfills, exists for determining uncontrolled LFG emissions from landfills. Even the procedure for modeling landfills can be quite complex and subject to many different interpretations of how to address LFG generation factors for site-specific factors and how to apply models effectively to landfills. Given the complexity of determining baseline emissions and the fact that actual measurements are not widely available, the Standard only requires that project developers measure actual GHG credits developed via combustion of collected methane.

For GHG credits achieved via methane destruction, the only potential baseline-related activity involves landfills where eligible and non-eligible LFG streams exist. As illustrated in section 6.1 below, some landfills may already be subject to emission control standards for their LFG. However, these sites may install LFG collection and control systems on areas of the landfill in advance of regulatory requirement dates or at areas that are not subject to emission control requirements. Additionally, some landfills may have installed voluntary LFG collection and control systems before the eligibility date of January 1, 2000 and, therefore, the resulting methane control achieve by these systems do not provide eligible GHG credits. For these situations, project developers would need to develop a procedure to isolate and measure the amount of eligible methane collected and sent to a combustion device. Per Figure 2, after a project developer identifies an eligible stream, the developer would be required to install a methane flow rate monitoring device and follow the procedures outlined in Sections 8.2.1 or 8.1.1 to determine eligible methane flow rate. The requirements of combustion efficiency determination in Sections 8.1.2 or 8.2.2 also apply even if the combustion device combusts both eligible and non-eligible LFG streams. All associated monitoring, recordkeeping, verification, and reporting requirements of this standard would apply.

Non-eligible LFG sources

Some projects may involve the destruction of methane at landfills where a portion of the LFG is required to be controlled. At these sites, through early implementation of LFG collection and control systems or through collection methane from unregulated sources at such landfills, a portion of the methane destroyed may be eligible under this standard. Additionally, some landfills may have implemented voluntary LFG collection and control before the eligibility date of January 1, 2000 and such streams would not be eligible under this Standard of Practice. Figure 2 demonstrates the potential scenario where eligible and non-eligible methane containing LFG streams are controlled within one project. For these situations, a project developer would need to monitor the amount of eligible methane going to the combustion device per the requirements of Section 8.1.1. The project owner must demonstrate that these streams are eligible per the requirements of Section 2 and must be able to demonstrate that the methane monitoring procedures are monitoring eligible LFG streams. All other requirements for calculating and verifying GHG credits would apply (e.g., combustion efficiency, monitoring, recordkeeping, verification, reporting).

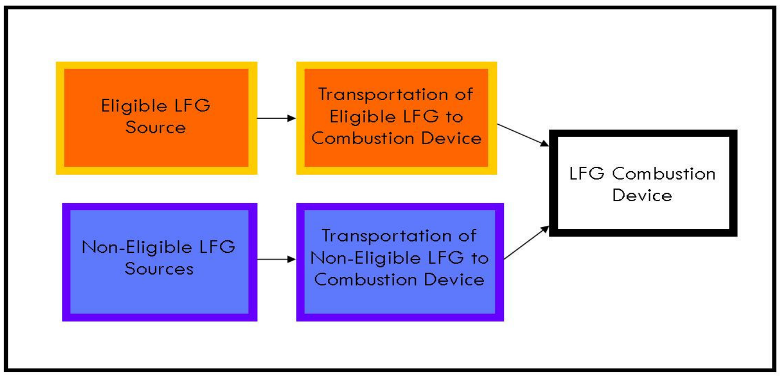

Figure 2: Example of Eligible and Non-eligible LFG Streams

Project developers are required to clearly outline each project and provide supporting documentation to justify each eligible LFG stream. As outlined in Sections 5 and 6, this documentation would include relevant air quality permits, identification of all emission sources in the facilities permit, and a general summary describing the rationale behind the project developer's determination of project eligibility. Through the recordkeeping, verification, and reporting requirements of this methodology, project eligibility will be documented.

6.1.2 Projects Accounting for Destruction of Methane and Displacement of Energy

GHG reductions attributable to displaced natural gas or grid electricity consumption are addressed in this methodology but require the GHGS methodology titled Quantification Methodology for Displacement Projects.

7 Greenhouse Gas Quantification

This section includes procedures to quantify GHG emissions for all potential SSRs identified in Section 5.2 for the scenarios described in Section 5.1. For the purposes of the landfill gas methodology, GHG quantification is the process of obtaining a value for GHG emissions for each of the SSRs selected for quantification. Thus the quantification of GHG emission from a source could be done by:

- Direct measurement of the GHG emission from the source
- Estimation of the GHG by using an emission factor (measured or estimated), inputs, outputs and activity levels.

Scenario emission are calculated by adding the GHG emissions associated with each relevant SSRs (for each scenario) as presented in Table 7 of this document.

7.1 Controlled and Related SSRs

7.1.1 SSR 3 – Compression, Blower and Gathering System for landfill gas Capture

$$E_{SSR3} = CONS_{ELECM} \times EF_{ELEC} + CONS_{HEATM} \times EF_{HEAT} + CONS_{FFM} \times EF_{FF}$$

Where;

E_{SSR3}	SSR 3 GHG emissions from energy used to capture landfill gas (t CO_2e)
$CONS_{ELECM}$	Electricity consumption for capture of landfill gas, if any (MWh)
EF_{ELEC}	Carbon emissions factor of electricity used to collect landfill gas (tCO_2/MWh)
$CONS_{HEATM}$	Heat consumption for capture of landfill gas, if any (GJ)
EF_{HEAT}	Carbon emissions factor of heat used to collect landfill gas (t CO_2/GJ)
$CONS_{FFM}$	Fossil fuel consumption for capture of landfill gas, if any (GJ)
EF_{FF}	Carbon emissions factor of fossil fuel used to collect landfill gas (t CO_2/GJ)

7.1.2 SSR 5 – Flare Operation

When the captured methane is destroyed in a flare, combustion emissions and un-combusted methane are released. For the purposes of this methodology, the unburned methane emissions must be evaluated and included in the overall GHG credit assessment. Since CO_2 emissions resulting from the combustion of LFG are considered to be “short-cycle” emissions and do not result in an increase in overall GHG emissions, they are not evaluated.

$E_{SSR5} = IMC_{FL}$

Where;

IMC_{FL} GHG emissions from incomplete methane combustion from flaring (t CH_4)

$IMC_{FL} = MM_{FL}\ (1 - Eff_{FL}) * GWP_{CH4}$

Where;

IMC_{FL} GHG emissions from incomplete methane combustion from flaring (t CH_4)

MM_{FL} Methane measured sent to flare (t CH_4)

Eff_{FL} Flare combustion efficiency as determined by either simple or advanced combustion efficiency methods (see section 8.1.2 or 8.2.2)

GWP_{CH4} Global Warming Potential of Methane (21)

7.1.3 SSR 7 – Boiler or other combustion device

When captured methane is burned in a boiler or other combustion device, combustion emissions and un-combusted methane are released. For the purposes of this methodology, the unburned methane emissions must be evaluated and included in the overall GHG credit assessment. Since CO_2 emissions resulting from the combustion of LFG are considered to be "short-cycle" emissions and do not result in an increase in overall GHG emissions, they are not evaluated.

$E_{SSR7} = IMC_{CU}$

Where;

IMC_{CU} GHG emissions from incomplete methane combustion from boiler or combustion unit(t CO_2e)

$IMC_{CU} = MM_B\ (1 – Eff_{CU}) * GWP_{CH4}$

Where;

IMC_{CU} GHG emissions from incomplete methane combustion from boiler or combustion unit (t CH_4)

MM_{CU} Methane measured sent boiler or combustion unit (t CH_4)

Eff_{CU} Boiler or combustion unit combustion efficiency as determined by either simple or advanced combustion efficiency methods (see section 8.1.2 or 8.2.2)

GWP_{CH4} Global Warming Potential of Methane (21)

7.1.4 SSR 8 - Engine, turbine or other electrical generating unit

When the captured methane is burned in a power plant, combustion emissions and un-combusted methane are released. For the purposes of this methodology, the unburned methane emissions must be evaluated and included in the overall GHG credit assessment. Since CO_2 emissions resulting from the combustion of LFG are considered to be "short-cycle" emissions and do not result in an increase in overall GHG emissions, they are not evaluated.

$E_{SSR8} = IMC_{EGU}$

Where;

E_{SSR8} SSR 8 GHG emissions from landfill gas destroyed through electrical generation unit (tCO_2e)

IMC_{EGU} GHG emissions from incomplete methane combustion from electrical generation unit ($t\ CO_2e$)

$IMC_{EGU} = (MM_{EGU}\ (1 - Eff_{EGU})^{*}\ GWP_{CH4}$

Where;

IMC_{EGU} GHG emissions from incomplete methane combustion from electrical generation unit ($t\ CH_4$)

MM_{EGU} Methane measured sent to electrical generation unit ($t\ CH_4$)

Eff_{EGU} Electrical generation unit combustion efficiency as determined by either simple or advanced combustion efficiency methods (see section 8.1.2 or 8.2.2)

GWP_{CH4} Global Warming Potential of Methane (21)

7.1.5 SSR-10 – Regulated Natural Gas Pipeline System

When the captured methane is injected into a regulated natural gas pipeline system, the eventual combustion of that LFG will result in combustion emissions and un-combusted methane are released. For the purposes of this methodology, the unburned methane emissions must be evaluated and included in the overall GHG credit assessment. Since CO_2 emissions resulting from the combustion of LFG are considered to be "short-cycle" emissions and do not result in an increase in overall GHG emissions, they are not evaluated.

$E_{SSR10} = IMC_{EGU}$

Where;

E_{SSR10} SSR 10 GHG emissions from landfill gas destroyed via injection in to a regulated natural gas pipeline system (tCO_2e)

IMC_{NGP} GHG emissions from incomplete methane combustion from natural gas pipeline systems ($t\ CO_2e$)

$IMC_{NGP} = (MM_{NGP}\ (1 - Eff_{NGP})*\ GWP_{CH4}$

Where;

IMC_{NGP} GHG emissions from incomplete methane combustion from natural gas pipeline system ($t\ CH_4$)

MM_{NGP} Methane measured sent to regulated natural gas pipeline system ($t\ CH_4$)

Eff_{NGU} Overall destruction efficiency of methane in a regulated natural gas pipeline system (98.1%; see section 5.1)

GWP_{CH4} Global Warming Potential of Methane (21)

7.1.6 SSR 11 – Electricity Grid

GHG reductions attributable to displaced grid electricity consumption are addressed in this methodology but require the GHGS methodology titled Quantification Methodology for Displacement Projects.

8 Monitoring

Methane Flow Rate

Methane flow rates to a control device are to be measured by a LFG flow meter and continuous or periodic sampling of the LFG to determine methane content. If eligible and non-eligible LFG are routed to the same control device, then flow meters shall be placed in a position to independently monitor eligible and non-eligible LFG flows before they are combined. If separate LFG flow meters cannot be implemented, the LFG project must provide an alternate method for approval, or the entire project will not be eligible.

For both the simple and advanced methane flow monitoring options, LFG flow metering is the same. Since accurate LFG flow is crucial to both methods, measurement methods are well established and minimal cost savings can be achieved through alternate flow rate measurements, the Standard of Practice does not provide for alternate flow monitoring options. However, eligible projects can choose from a wide range of flow monitoring techniques. This section outlines the monitoring requirements of this standard.

Projects that choose to use the simple procedure to determine methane flow rate to the control device will conduct periodic sampling of the LFG for methane content and use a prescribed confidence factor that GE AES Greenhouse Gas Services has established to provide a conservative estimate of methane content of the LFG. Since monitoring of LFG flow is described earlier in this section, the only other measured parameter needed to calculate methane flow is the methane content of the LFG. Given that methane content of LFG can have significant variations based on landfill and wellfield operation, the most accurate and preferred method to determine methane flow rate is to monitor methane content of LFG continuously. However, continuous monitoring systems are more expensive due to equipment, manpower, and calibration costs.

Combustion Efficiency

Combustion efficiency represents the amount of methane destroyed by the control device used by the project. This protocol provides simple and advanced methods for the application and monitoring of control device combustion efficiency. Similar to the methane measurement methods, the simple method provides reduced monitoring requirements in exchange for more conservative assumptions in the credit calculations where the advance method requires more stringent monitoring but allows greater combustion efficiencies to be used.

8.1 Simple Monitoring Plan

8.1.1 Determination of Methane Flow Rate

To reduce methane measurement costs, the simple method allows for monthly methane measurements using portable infrared gas analyzers or comparable analytical device. Methane sampling using the simple method must be conducted at least once a month and the analyzer must be calibrated before use using a calibration gas with methane content similar to that expected from the measured LFG. Calibrations shall be conducted based on the specifications provided by the analyzer manufacturer. LFG samples shall be taken in the same location as the LFG flow meter and can be taken directly via a sampling port or by using a SUMMA® container or Tedlar bag. Methane content must be measured when the flow rate is within 5 percent of the average flow rate for that month.

Since the amount of methane in LFG can vary between sampling events and some studies have shown the level of variation to be as much as 20%[3], this standard requires that a confidence factor be applied to the measured methane content in order to assure that calculated methane flow rate does not exceed actual values across normal variations. Therefore, each methane flow measurement must be multiplied by a confidence factor of 0.8 in flow rate calculations and the most recent methane concentration measurement will be used until the next measurement is taken. This confidence factor assumes a conservative methane variation of 20% between measurements and is based on a 2003 CDM Methodology[12].

The following equation shall be used to calculate methane flow rate and shall be used to provide a flow rate calculation for every hour:

MM_i = LFG flow (cubic feet per minute) * measured methane content (% by volume)/100 * 0.0415 (lb/cubic foot)* (528/(T+460) * (P/14.7) *60 minutes/hour * 0.8 (confidence factor) * 0.000454 tonnes/lb

Where;

MM_i = Measured methane flow rate of entering the combustion device or natural gas pipeline (tonnes/hr)

0.0415 = density of methane at 68^{O}F and 1 atm

T = Temperature of LFG at flow meter (^{O}F)

P = Pressure of LFG at flow meter (p.s.i.)

If a mass flow meter and/or integrated methane flow rate measurement system is utilized, the project developer must provide details of the associated calculations used to determine methane mass flow rate.

The purpose of the following sections is to outline the requirements of the Standard for flow meters used to measure LFG flow to a combustion device. LFG flow data is used to calculate the amount of GHG credits generated by an eligible project and the accuracy of LFG flow monitoring is crucial in establishing credible GHG credits and ensuring consistency across eligible credit projects. All performance criteria and required records must be met and kept for a

[12] CDM – Executive Board AM0002/Version 01. Approved baseline methodology: "Greenhouse Gas Emission Reductions through Landfill Gas Capture and Flaring where the Baseline is Established by a Public Concession Contract." 26 September 2003.

project to develop valid GHG credits. Additionally, specific LFG flowmeter requirements have been developed for use as guidance by project developers. A project developer must demonstrate that LFG flowmeters meet the specific guidance provided below or justify an equivalent monitoring technique. The following outlines the requirements that shall be followed to install, operate, and calibrate LFG flow meters.

8.1.1.1 Initial Requirement for LFG Flow Meters

For the purposes of initial certification, each flow meter used to measure LFG flow rate for this protocol shall meet a manufacturer certified flow meter accuracy of +/- 5 percent and such accuracy documentation provided by the flow meter manufacturer. The flow meter must be installed and operated in accordance with manufacturer's specification and in a location that has minimal turbulent flow; EPA Method 1 can be used as guidance.

8.1.1.2 Flow Meter Maintenance and Inspection Requirements

Conduct maintenance of each LFG flow meter at least once every calendar year. Annual maintenance can be completed through one of the following four options:

1. Factory calibration of the flow meter. An alternate flow meter meeting the requirements of this methodology should be utilized in the interim period;
2. On-site calibration of the flow meter by a manufacturer's representative or other qualified third-party using the manufacturer's approved methodology;
3. In-line comparison with another flow meter device that meets the requirements of this methodology. Such a comparison should be conducted in a location proximate to the primary flow meter device and the comparison flow meter must be calibrated for characteristics of this location;
4. In-line comparison with a direct measurement of volumetric flow rate by a qualified third-party using EPA Methods 1 and 2, 1A and 2A, or other field test method, as appropriate.

When annual flow meter maintenance is conducted via options 3 or 4, the flow meter must be accurate to within +/-5 percent of the comparative test conducted. If the comparative test on the flow meter does not demonstrate an accuracy standard of +/-5 percent, refer to Section 8.1.1.3.

Conduct inspections of the flow meter at least once every calendar quarter. Flow meter inspections must include:

1. Visual inspection of the flow meter to identify any defects or operational issues;
2. Based on the findings of step 1, when needed perform cleaning of the flow meter components exposed to the LFG
3. Observation of the flow meter readings and historical flow data to confirm that the flow meter is operating normally and recording data within an expected range of flow rate values; and
4. Any other maintenance activities recommended by the flow meter manufacturer.

8.1.1.3 Failure of Annual Maintenance Option

If the flow meter accuracy specification outlined in Section 8.1.1.2 for maintenance options 3 and 4 is not met, repair, recalibrate, or replace the flow meter as necessary until the flow meter accuracy specification has been achieved. Until flow meter accuracy tests are acceptable, the LFG flow meter is considered "out-of-control" beginning with the date and hour after the last successful maintenance activity performed on the flow meter and continuing until the date and hour that a methodology compliant flow meter is in place. If the in-line comparison indicates that the flow meter readings exceed the 5 percent accuracy criteria of this standard on the high-side of the comparative standard, then all flow data collected during the "out-of-control" period must be reduced by the measured percent difference between the flow meter and in-line comparison readings.

8.1.2 Determination of Combustion Efficiency

The simple method of determining combustion efficiency under this standard involves continuous monitoring of the control device combustion temperature for open or enclosed flares and temperature or other representative operating parameter for LFG utilization technologies. As discussed in Section 2.1, default combustion efficiency for open flares is 96% (except for flares that do not meet the operational requirements of 40 CFR 60.18, then a 50% combustion efficiency is applied). Combustion efficiency for enclosed combustion devices is 98% (except for enclosed flares that do not meet the retention time requirements, then a 90% combustion efficiency is applied). 98.1% is applied for injection into regulated natural gas pipeline systems. Therefore, the credit project must continuously monitor the control device to demonstrate proper operation. For open and enclosed flaring systems, a minimum combustion temperature of 500^{O}C must be demonstrated for proper operation. For injection into natural gas pipeline systems, only flow of LFG to regulated pipeline system must be monitored. Continuous monitoring for the purposes of this standard means collecting at least one data point every fifteen minutes and at least four data points per hour. If at least 3 15-minute data periods indicate operation of the control device, then the credit project is allowed to apply the default control device efficiency for that hour. If less than 3 15-minute data periods indicate that the control device is not operating, or if the monitor has failed to record the data, then a control efficiency of 0% is applied for that hour.

Combustion efficiency of methane is the second critical component of this methodology for project developers of LFG credit projects. Eligible projects must follow the evaluation and recordkeeping requirements of section 8.3 to demonstrate continuous destruction of methane from LFG. As outlined in the above requirements, if a project developer cannot demonstrate operation of combustion device, then the methodology automatically requires that a 0 percent combustion efficiency be applied for the period of time that operation cannot be demonstrated, thus no GHG credits are generated during that time period.

8.2 Advanced Monitoring

8.2.1 Determination of Methane Flow Rate

GHG credit projects choosing to use the advanced methane flow rate procedures will conduct continuous monitoring of methane content of LFG. By conducting continuous monitoring of methane content, these credit projects can account for 100 percent of the methane flow to the control device.

Continuous methane monitoring for the purposes of this standard means collecting at least one data point every fifteen minutes and at least four data points per hour. To determine the hourly methane content of the LFG, an arithmetic average of the available data points shall be taken. If no more than one 15 minute period of data unavailable, then the credit project can average the remaining 3 periods of data to determine the hourly methane concentration. If 2 or more 15-minute periods of data are unavailable, then available data shall be averaged and a confidence factor of 0.8 applied to that data to determine the hourly methane content. If no data is available for an entire hour, then the most recent measured methane content data shall be used and a confidence factor of 0.8 applied to that data to determine methane content until the next methane content measurements are available.

The continuous methane monitoring system shall be calibrated at least monthly and be accurate to within +/- 5 percent of the calibration standard. For periods where the methane monitoring system is out of calibration, the measured methane content taken for the first hour after the most recent successful monitoring system calibration test shall be used and a confidence factor of 0.8 applied to that data to determine methane content until a successful monitoring system calibration is demonstrated, per the methane flow rate equation provided in Section 8.1.1. After a successful monitoring system calibration is demonstrated, then use of the confidence factor is no longer required for data collected after the successful calibration.

The following equation shall be used to calculate methane flow rate and shall be conducted to provide a flow rate calculation for every hour:

MM_i = *LFG flow (cubic feet per minute) * measured methane content (% by volume)/100 * 0.0415 (lb/cubic foot) * (528/(T+460) * (P/14.7)* 60 minutes/hour * 0.000454 tonnes/lb*

Where;

MM_i = Measured mass flow rate of methane entering the combustion device or natural gas pipeline (tonnes/hr)

0.0415 = density of methane at $68^{O}F$ and 1 atm

T = Temperature of LFG at flow meter (^{O}F)

P = Pressure of LFG at flow meter (p.s.i.)

If a mass flow meter and/or integrated methane flow rate measurement system is utilized, the project developer must provide details of the associated calculations used to determine methane mass flow rate.

The same requirements for flow meters used to measure landfill gas (LFG) flow to a combustion device for the simple device should be used for the advanced approach. (Refer sections 8.1.1.1 to 8.1.1.3)

8.2.2 Advanced Combustion Efficiency

GHG credit projects that choose to use the advanced method for determining combustion device control efficiency will conduct initial and annual performance tests according to EPA measurement methods, and conduct continuous monitoring activities to demonstrate ongoing combustion efficiency. The purpose of the advanced method is to allow eligible facilities to achieve higher combustion efficiencies that the default levels provided in section 8.1.2. Through the use of the advanced methods presented in this section, eligible facilities can take full credit for demonstrated site-specific combustion efficiency.

Under the advanced combustion efficiency method, eligible projects shall conduct simultaneous testing of methane concentration at the inlet and outlet of the combustion device. Through concurrent testing of inlet and outlet concentrations, overall methane combustion efficiency can be determined. After an eligible project determines combustion efficiency, it shall continuously monitor outlet methane concentration, or some other operational parameter, to ensure that the combustion device is operating in a manner similar to that when the methane testing was conducted.

To measure the amount of methane entering the combustion device, eligible projects can use the monitoring methods outlined in section 8.1.1 or 8.2.1 of this document as long as inlet methane concentration measurements are taken concurrent with combustion device outlet measurements. Data from the inlet methane monitoring activities shall be used in the following equation to determine methane flow into the combustion device in units of pounds per hour:

MM_{ii} = LFG flow (cubic feet per minute) * measured methane content (% by volume)/100 * 0.0415 (lb/cubic foot)* (528/(T+460) * (P/14.7)* 60 minutes/hour

Where:

MM_{ii} = Mass flow rate of methane at the inlet of the combustion device (lb/hr)

0.0415 = density of methane at 68^{O}F and 1 atm

T = Temperature of LFG at flow meter (^{O}F)

P = Pressure of LFG at flow meter (p.s.i.)

Testing of methane at the outlet of the combustion device shall be conducted using approved measurement methods and must also include exhaust flow and oxygen measurements. These parameters shall be used to determine methane flow at the outlet of the combustion device in units of pounds per hour based on the following equation:

MM_{IO} = Combustion device exhaust flow (cubic feet per minute) * measured methane content (% by volume)/100 * 0.0415 (lb/cubic foot)* (528/(T+460) * (P/14.7)* 60 minutes/hour

Where:

MM_{IO} = Mass flow rate of methane at the outlet of the combustion device (lb/hr)

0.0415 = density of methane at 68^{O}F and 1 atm

T = Temperature of LFG at flow meter (^{O}F)

P = Pressure of LFG at flow meter (p.s.i.)

To determine combustion device efficiency, eligible projects shall conduct inlet and outlet testing of methane simultaneously for a period of at least 3 hours. For each hour of methane testing, combustion efficiency shall be calculated using the following equation, and then averaged for the entire testing period:

$$CD_{eff} = 1 - (MM_{IO}/MM_{II})$$

To ensure ongoing combustion device efficiency, eligible projects must choose an operating parameter to monitor during the determination of combustion efficiency. This operating parameter may be temperature, exhaust methane or total hydrocarbon concentration, oxygen content of exhaust, or any other parameter that can be correlated to combustion efficiency. During the testing period to determine combustion efficiency, the selected operating parameter shall be recorded and averaged over the same time frame. Eligible projects shall conduct initial and annual combustion efficiency testing.

After the testing period, the measured combustion efficiency can be used to calculate CO_2e credits according to the equation in section 10 provided the chosen operating parameter(s) remain above the average level determined during the most recent testing period. The eligible project shall continuously monitor the chosen operating parameter(s) and develop 1-hour block averages of the operating parameter for comparison with the monitoring parameter level determined during the most recent combustion efficiency testing. Continuous monitoring for the purposes of this standard means collecting at least one data point every fifteen minutes and at least four data points per hour. If any 1-hour block operating parameter average falls below the level set during the most recent combustion efficiency testing, and the combustion device is still in operation, then the appropriate default combustion efficiency value in section 8.1.2 shall be used. If less than 3 15-minute data periods indicate that the control device is not operating, or if the monitor has failed to record the data, then a control efficiency of 0% is applied for that hour.

Combustion efficiency of methane is the second critical component of this methodology for project developers of LFG credit projects. Eligible projects must follow the evaluation and recordkeeping requirements of section 8.3 to demonstrate continuous destruction of methane from LFG. As demonstrated in the above requirements, if a project developer cannot demonstrate operation of combustion device, then the methodology automatically requires that a 0 percent combustion efficiency be applied for the period of time that operation cannot be demonstrated, thus no GHG credits are generated during that time period.

8.3 Monitoring Plan

The following table outlines the parameters that need to be monitored for each SSR.

SSR Identifier & Name	Parameter Identifier	Parameter to be monitored	Indicator/ Unit	Instrument, monitoring frequency and location or reference for default value
3. Compression, Blower and Gathering System for landfill gas capture system	$CONS_{ELECM}$	Electricity consumption for capture LFG	MWh	Power meter (revenue grade accuracy required), continuously monitored or electrical invoices (for this system only if available)
	EF_{ELECM}	Emissions factor of electricity used to collect LFG	t CO_2e/MWh	Provide in Annex 1 (State average)
	$CONS_{HEATM}$	Heat consumption for capture of LFG, if any	GJ	Monitored continuously
	EF_{HEATM}	Emissions factor of heat used to collect LFG	tCO_2e/GJ	
	$CONS_{FFM}$	Fossil fuel consumption for capture of LFG	GJ	Monitored continuously
	EF_{FF}	Carbon emissions factor of fossil fuel used to collect LFG	tCO_2e/GJ_{FF}	
5. Flare Operation	C_{CH4}	Concentration of methane in LFG, measured on wet basis	% volume, wet basis	Simple Monitoring: Monthly methane measurements Advanced Monitoring: Continuous methane measurements.
	MM_{FL}	Methane measured sent to flare	tCH_4	Continuous LFG flow metering Methane Concentration (simple or advance method)
	Eff_{FL}	Flare combustion efficiency as determined by either simple or advanced combustion efficiency	% reduction of methane	Simple approach: Appropriate default combustion efficiency as outlined in Section 5.1.

SSR Identifier & Name	Parameter Identifier	Parameter to be monitored	Indicator/ Unit	Instrument, monitoring frequency and location or reference for default value
		methods		Advanced approach: · Initial and annual performance tests according to approved measurement methods, and conduct continuous monitoring activities to demonstrate ongoing combustion efficiency. · Conduct simultaneous testing of methane concentration at the inlet and outlet of the combustion device annually. Through concurrent testing of inlet and outlet concentrations, overall methane combustion efficiency can be determined. After an eligible project determines combustion efficiency, it shall continuously monitor outlet methane concentration, or some other operational parameter, to ensure that the combustion device is operating in a manner similar to that when the methane testing was conducted. · To measure the amount of methane entering the combustion device, eligible projects can use the monitoring methods outlined in

SSR Identifier & Name	Parameter Identifier	Parameter to be monitored	Indicator/ Unit	Instrument, monitoring frequency and location or reference for default value
				section 8.2.1 and 8.2.2 of this document as long as inlet methane concentration measurements are taken concurrent with combustion device outlet measurements
7. Onsite Boiler or Other Combustion Device	C_{CH4}	Concentration of methane in LFG	% volume, wet basis	Simple Monitoring: Monthly methane measurements Advanced Monitoring: Continuous methane measurements.
	MM_{CU}	Methane measured sent to boiler or combustion unit	t CH_4	Continuous LFG flow metering Methane Concentration (simple or advance method)
	Eff_{CU}	Boiler or combustion unit combustion efficiency as determined by either simple or advanced combustion efficiency methods	% reduction of methane	Simple approach: Appropriate default combustion efficiency as outlined in Section 5.1. Advanced approach: · Initial and annual performance tests according to approved measurement methods, and conduct continuous monitoring activities to demonstrate ongoing combustion efficiency. · Conduct simultaneous testing of methane concentration at the inlet and outlet of the combustion device. Through concurrent testing of inlet and outlet concentrations,

SSR Identifier & Name	Parameter Identifier	Parameter to be monitored	Indicator/ Unit	Instrument, monitoring frequency and location or reference for default value
				overall methane combustion efficiency can be determined. After an eligible project determines combustion efficiency, it shall continuously monitor outlet methane concentration, or some other operational parameter, to ensure that the combustion device is operating in a manner similar to that when the methane testing was conducted. · To measure the amount of methane entering the combustion device, eligible projects can use the monitoring methods outlined in section 8.2.1 and 8.2.2 of this document as long as inlet methane concentration measurements are taken concurrent with combustion device outlet measurements
8. Onsite Engine, turbine or other electrical generating unit	C_{CH4}	Concentration of methane in LFG	% volume (wet Basis)	<u>Simple Monitoring:</u> Monthly methane measurements Advanced Monitoring: Continuous methane measurements.
	MM_{EGU}	Methane measured sent to electrical generation unit	t CH_4	Continuous LFG flow metering Methane Concentration (simple or advance method)

SSR Identifier & Name	Parameter Identifier	Parameter to be monitored	Indicator/ Unit	Instrument, monitoring frequency and location or reference for default value
	Eff_{EGU}	Electrical generation unit combustion efficiency as determined by either simple or advanced combustion efficiency methods	% reduction of methane	<u>Simple approach:</u> Appropriate default combustion efficiency as outlined in Section 5.1. <u>Advanced approach:</u> · initial and annual performance tests according to approved measurement methods, and conduct continuous monitoring activities to demonstrate ongoing combustion efficiency. · Conduct simultaneous testing of methane concentration at the inlet and outlet of the combustion device. Through concurrent testing of inlet and outlet concentrations, overall methane combustion efficiency can be determined. After an eligible project determines combustion efficiency, it shall continuously monitor outlet methane concentration, or some other operational parameter, to ensure that the combustion device is operating in a manner similar to that when the methane testing was conducted. · To measure the amount of methane entering the combustion device,

SSR Identifier & Name	Parameter Identifier	Parameter to be monitored	Indicator/ Unit	Instrument, monitoring frequency and location or reference for default value
				eligible projects can use the monitoring methods outlined in section 8.2.1 and 8.2.2 of this document as long as inlet methane concentration measurements are taken concurrent with combustion device outlet measurements
11. Electricity Grid	EF_{EG}	Emission factor for production of electricity used on site.	tCO_2e/kWh	Simple method: · State-level emission factors found in Annex A, "State-level Greenhouse Gas Emission Factors for Electricity Generation." Advanced method: · if an end-user contract is in place. In this case, the emission factor used by the offsite power generator will be used
12. Fossil fuel production and distribution	CFPD	Emission factor for the production and distribution of conventional fuel (natural gas, diesel, gasoline, etc…)	t CO2e/GJFF	
	GJFFC	Amount of fossil fuel consumed in the scenario	GJFF	Fuel consumption should be monitored continuously.

9 QA/QC and Data Management

Data sets collected from the monitoring system during ongoing project activities must be retrievable as unmodified results. They may be summarized in a fashion that is suitable for accounting purposes, but the data sets shall be preserved so that emission reductions can be verified by a third party. (Refer to monitoring procedures in Section 8).

9.1 Recordkeeping procedures

For purposes of independent verification and historical documentation, eligible projects shall be required to keep all information outlined in this methodology for various periods. The length of time a project is required to keep records depends on the type of information.

The following type of information shall be kept accessible for the entire period of time that the landfill is providing GHG credits:

- Relevant sections of the landfill operating permits (solid waste and air)
- Collection and control device information (installation dates, equipment list, etc)
- LFG flow meter information (model number, serial number, manufacturer's calibration procedures)
- Methane monitor information (model number, serial number, manufacturer's/EPA calibration procedures)
- Control device monitor information (model number, serial number, manufacturer's/EPA calibration procedures)

The following information shall be kept assessable for a period of 5-years after the information is generated:

- LFG flow data
- LFG flow meter maintenance and inspection data
- Methane monitoring data
- Methane monitor calibration data
- Control device monitoring information
- Control device monitor calibration data
- CO_2e hourly calculations
- CO_2e daily, monthly, and annual tonnage calculations
- Initial and annual verification records and audit results

Eligible projects may keep these records in electronic and/or hard copy form. However, all information shall be readily available for verification.

Simple Methane Flow Rate

For the simple methane flow rate method, the following records must be kept in order to demonstrate valid methane flow rate calculations:

- LFG flow meter type, model and serial number
- Date, time, and results of LFG flow meter maintenance and inspection activites
- Date, time, and location of methane measurement
- Methane content of LFG (% 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
- Hourly calculations of methane flow rate. Each hour shall have one associated methane flow rate value.

Advanced Methane Flow Rate

For the advanced methane flow rate method, the following records must be kept in order to demonstrate valid methane flow rate calculations:

- LFG flow meter type, model and serial number
- Date, time, and results of LFG flow meter maintenance and inspection activities
- Date and time of methane measurement
- Average methane content of LFG (% by volume) for each hour of operation
- Location of methane measurement instrument
- Methane measurement instrument type and serial number
- Summary of methane measurement methods and QA/QC procedures
- Date, time, and results of instrument calibration
- Corrective measures taken if instrument does not meet performance specifications
- Hourly calculations of methane flow rate. Each hour shall have one associated methane flow rate value.

Simple Combustion Efficiency

For the simple method of determining combustion efficiency, the following records must be kept in order to validate combustion device operation and apply the default combustion efficiency:

- Type of combustion device and model number if applicable
- Type and location of monitoring parameter and monitoring method
- Date, time, and status of each control device monitoring parameter
- Applied combustion efficiency for each hour
- Results of initial and periodic inspection of monitoring device

Advanced Combustion Efficiency

For the advanced method of determining combustion efficiency, the following records must be kept in order to validate combustion device operation and demonstrate that site-specific combustion efficiency can be used to quantify GHG credits:

- Type of combustion device and model number if applicable
- Type and location of monitoring parameter and monitoring method
- Date, time, and status of each control device monitoring parameter
- Results of combustion device efficiency testing and calculations of applicable combustion efficiency.
- Operating parameter value set during previous combustion efficiency testing and hourly average operating parameter value
- Applied combustion efficiency for each hour
- Results of initial and periodic inspection of monitoring device

10 Emission Reduction Quantification

10.1 Methane Destruction Projects

When a project developer quantifies and request certification of the GHG credits associated with methane destruction only, then a value of 0 can be assigned to the baseline and the emission reduction are quantify using the following approach.

Eligible projects will need to determine methane flow and combustion efficiency per the guidance in Sections 8.1 and 8.2. Based on these data, hourly GHG credits for the eligible projects can be quantified. Overall, the quantification of GHG credits involves the calculation of eligible methane delivered to a control device, determination of the destruction efficiency of the methane control device, conversion of methane destruction to CO_2e, and reduction of GHG credits based on energy needed to collect and transport the methane to the control device. The following equation shall be used to calculate the GHG credits for each hour of operation:

$ERy = \Sigma MM_i * GWP - \Sigma SSR_A$ where,

ERy metric tonnes of eligible GHG credits

ΣMM_i cumulative mass flow rate of methane to the combustion device or injected into natural gas pipeline (tonnes) (can be based on either the simple or advanced method under section 8.1.1 or 8.2.1)

ΣSSR_A summation of all applicable emissions from SSR's as calculated per Section 7.1 for the time period associated with the cumulative methane mass flow rate used in this equation

GWP global warming potential of methane (21)

10.2 Displacement Projects Electrical

GHG reductions attributable to displaced grid electricity consumption are addressed in this methodology but require the GHGS methodology titled Quantification Methodology for Displacement Projects.

10.3 Displacement Projects Thermal

GHG reductions attributable to displaced thermal energy consumption are addressed in this methodology but require the GHGS methodology titled Quantification Methodology for Displacement Projects.

11 Documentation and Reporting

Initial Reporting Requirements

The project developer will provide an initial Project Build Document (PBD) for the specific project based on the PBD template provided by GHGS. The document is intended to serve as guidance for the project developers and ensures consistency and transparency between the various projects proposed and submitted to GGS. It is the responsibility of the project developer to ensure that all requirements of the LFG Methodology are addressed when drafting the PBD. This PBD document template contains guidance regarding the type of information that must be provided by the project developer to provide GGS with a complete understanding of the proposed GHG project. The PBD outline addresses the various elements of the CMM Methodology that are required for GGS to document project eligibility, size, and scope. The project developer should read the guidance provided carefully and complete the PBD accordingly. The structure of the PBD includes the following items:

- Executive Summary
- Project Description
- Eligibility
- Application of the LFG Methodology
- Estimation of GHG Emissions by Sources
- Quantification of Project Greenhouse Gas Reductions
- Monitoring
- Recordkeeping
- Reporting
- References
- Project Flow Diagrams

Semi-Annual Reporting Requirements

The project developer will provide a semi-annual project status report that includes the following items:

- Executive summary of project status and signed statement certifying that the collection and control of the identified landfill gas stream is the result of voluntary action and not required by Federal, State, or Local requirements or consent order and that the project is in compliance with all applicable Federal, State, and Local ordinances.

- Documentation of any changes or modifications to the project infrastructure or operation.
- Summary of project eligibility status including: expected dates for compliance with applicable collection and control requirement of the Landfill NSPS or other applicable regulations; current NMOC emission rate calculated according to 40 CFR 60.757(b)(1)(ii) for projects at landfills not subject to the collection and control requirements of the Landfill NSPS or other applicable regulations; and documentation of changes to any items related to demonstrating project eligibility that were provided in the initial PBD.
- Results of all verification activities including verification report, identified corrective actions, and documentation of resolution of corrective actions.
- Monthly and semi-annual summaries of GHG emissions and emission reductions generated by project based on the LFG Quantification Spreadsheet provided by GHGS. The project developer must provide the completed spreadsheet.
- Summary of all monitor calibration activities and any associated corrective actions.
- Estimated annual GHG credit generation for subsequent 5-year period, or until expected project termination date, based on LFG Quantification Spreadsheet provided by GHGS.

ANNEX A – State-level Greenhouse Gas Emission Factors for Electricity Generation[13]

State	metric ton CO_2e/MWh
Alabama	0.611
Alaska	0.563
Arizona	0.461
Arkansas	0.594
California	0.138
Colorado	0.929
Connecticut	0.515
Delaware	0.842
Florida	0.650
Georgia	0.644
Hawaii	0.824
Idaho	0.000
Illinois	0.534
Indiana	0.968
Iowa	0.899
Kansas	0.790
Kentucky	0.901
Louisiana	0.603
Maine	0.408
Maryland*	0.613
Massachusetts	0.561
Michigan	0.790
Minnesota	0.720
Mississippi	0.599
Missouri	0.862
Montana	0.586
Nebraska	0.638
Nevada	0.755
New Hampshire	0.338
New Jersey	0.257
New Mexico	0.952
New York	0.361
North Carolina	0.564
North Dakota	0.993
Ohio	0.823
Oklahoma	0.802
Oregon	0.080

[13] Energy Information Administration. 2001. *Updated State-level Greenhouse Gas Emission Factors for Electricity Generation.*

State	**metric ton CO_2e/MWh**
Pennsylvania	0.554
Rhode Island	0.418
South Carolina	0.370
South Dakota	0.325
Tennessee	0.565
Texas	0.702
Utah	0.880
Vermont	0.008
Virginia	0.493
Washington	0.083
West Virginia	0.895
Wisconsin	0.813
Wyoming	0.995

*Includes the District of Columbia