Bioenergy Association of New Zealand

NZ GASEOUS BIOFUELS GHG CARBON INTENSITY METHODOLOGY

Version: Rev.6, Peer review & Steering Group comments incorporated

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1. SUMMARY

1.1. Purpose

The Bioenergy Association of NZ has engaged Toitū Envirocare to develop a biogas and biomethane greenhouse gas (GHG) accounting methodology for its members and the emerging sector within NZ. This Carbon Intensity methodology document covers the three dominant waste-to-energy processes of municipal wastewater treatment, landfill gas capture, and anaerobic digestion (AD) of organic waste to produce biogas and biomethane. Biogas and its refined derivative biomethane are referred to collectively as gaseous biofuels.

The intended use of the carbon intensity methodology is to:

1. Provide a publicly available, standardised GHG accounting methodology for evaluating the carbon intensity for biogas and biomethane production and use which meets international best practice;
2. Provide the key metrics and measurements required for biogas and biomethane products to satisfy the GHG accounting required for renewable energy certification (REC) schemes;
3. Establish NZ sector requirements for measurement, monitoring, and reporting as it pertains to biogas and biomethane product carbon footprint.

Internationally biogas which is refined and traded through a pipeline network is often referred to as Renewable Natural Gas (RNG). In New Zealand neither the Gas Act 1992 or NZS5442 - Specification for reticulated natural gas refer to RNG. Distributed gas is referred to as biomethane.

1.2. Instructions for Use

This gaseous biofuel carbon footprint methodology is a voluntary guideline. As a voluntary guideline, “should and shall statements” have been included to ensure that there is consistency in approach otherwise the value of the methodology is diminished for everyone if it’s too broad and allows too much variation in approach. “shall” indicates a requirement and “should” indicates a recommendation. Shall statements are only required if an entity seeks compliance with this voluntary standard through verification.

This voluntary guideline does not dictate the requirements of a Renewable Energy Certificate (REC) scheme. This guideline does not mandate the frequency and depth of critical peer review required or verification process which should be outlined within an NZ REC Scheme. However, for alignment with lifecycle assessment (LCA) best practice a critical peer review is recommended in alignment with international standard ISO 140440F1.

1.3. Co-Development and Consultation

The development of this methodology is underpinned by ISO Standards for LCA (ISO 14044[2]) and Product Carbon Footprint (ISO 14067[3]). This methodology uses principles and

[1] ISO 14044: 2006 Environmental management — Life cycle assessment — Requirements and guidelines

[2] ISO 14044:2006, Life cycle assessment — Requirements and guidelines
[3] ISO 14067:2018, Carbon footprint of products — Requirements and guidelines for quantification

methodologies from leading international RNG REC schemes, and low carbon/renewable fuel standards (LCFS). The list of research documents can be found in the accompanying research paper that underpinned this methodology development.

Methodology development was done in collaboration with the Bioenergy Association of NZ, its sector steering group including engineering firms, energy firms, energy users and government.

This methodology is subject to a public consultation and feedback [TBC].

This methodology was developed by Toitū Envirocare Ltd with a third-party Independent Review from Lifecycles Australia.

1.4. Gaseous Biofuel Overview

Waste-to-energy (WtE) can simply be defined as the conversion of waste into electricity, heat, or biofuels. Many processes are currently being used to convert organic waste or biomass to energy. Anaerobic digestion (AD) has significant potential as a sustainable, circular economy model to support waste reduction and decarbonisation within NZ. A 2021 research document created by Beca, Firstgas Group (now Clarus), Fonterra and EECA outlines the potential of gaseous bioguel in NZ.[4] AD is a sequence of processes whereby micro-organisms break down organic matter in the absence of oxygen to produce a biogas mixture of primarily methane and carbon dioxide, with other trace amounts of gaseous by-products such as H_2S. Typically, the composition of the biogas is 50-70% CH_4 and 30-50% CO_2, with traces of H_2S and NH_3 (1% - 5%).

Organic waste is defined as waste products containing degradable organic matter. This includes domestic waste, commercial waste, animal manure, wastewater, organic industrial waste (such as sludge from wastewater treatment plants) agriculture waste and municipal solid waste (MSW).

Biogas is generally used directly onsite or supplied by sale to a nearby application. Biogas may also undergo refinement for blending and distribution to purchasers through a gas supply network. When refined for distribution through a pipeline network the refined gas must meet the requirements of NZS 5442(Int):2024 - Specification for reticulated natural gas. In the refining process the methane is separated from carbon dioxide and any other gaseous components such as H2S to produce biomethane. Collectively biogas and biomethane are referred to as gaseous biofuels and Renewable Natural Gas (RNG). Either gaseous biofuel can be used as a replacement for fossil-based gas, as a source of energy for heating, electricity generation, or use as a transportation fuel.

In the AD process digestion of the feedstock generates slurry/solid residue by-products (digestate and digestate sludge) as well as the gaseous outputs. This digestate residue can be

[4] Biogas and Biomethane in NZ - Unlocking New Zealand's Renewable Natural Gas Potential, 1/07/2021

used as fertiliser, providing a substitute for carbon intensive synthetic fertilisers such as urea, or further treated to create valuable products such as biochar.

Green CO_2 is also a coproduct of the anaerobic digestion of organic residues. "The creation of valuable products like digestate and green CO_2 bolster the financial and environmental benefits of RNG production and combined with the capture of biogenic emissions more than double the total emissions avoided throughout the product lifecycle" [4].

1.5. Intended Use and Users

The carbon accounting methodology's intended use and users within the Bioenergy Sector of NZ was agreed with key sector specialist stakeholders. This information defined the quality requirements and focus areas for the methodology development. Table 1 below was agreed with the Bioenergy Association and its steering group.

Avoided emissions was acknowledged as an important quantification for investment decisions and carbon credit generation that should be addressed with a calculation methodology at a later stage.

A full list of standards and references can be found in Appendix A.

Default values can be found in Appendix B.

Acronyms and definitions section can be found at the end of the document.

Table 1: Stakeholders and most relevant standards, GHG accounting typology

Stakeholder Type	Standards / References	GHG Accounting Typology
Certifier / Verifier / Peer Reviewer	14064-1 Organisation GHG; 14067 Product GHG Standard; GHG protocol organisational inventory ISO 14064-3 GHG assurance	Organisational emissions / Product Carbon Footprint
Project Developers / Producers	14064-2 Project GHG accounting; 14067 Product GHG Standard; International REC schemes; International Clean Fuel Standards	biogas /biomethane Carbon Intensity
Biofuel REC Certificate Scheme	European Energy Certificate System (EECS); Green Gas Certification Scheme (GGCS) UK; International REC (I-REC)	biogas /biomethane Carbon Intensity
Clean / Low Carbon Fuels standards	Canada's Clean Fuel Regulations (CFR); U.S. Renewable Fuel Standard (RFS) California's Low Carbon Fuel Standard (LCFS)	Biomethane Carbon Intensity
Consumers / Organisation GHG	14064-1 Organisation GHG; 14067 Product Standard; PAS 2050;	Organisational emissions / Product Carbon Footprint

2. GASEOUS BIOFUEL CARBON INTENSITY METHODOLOGY DEVELOPMENT

This carbon footprint methodology outlines the first New Zealand specific product carbon accounting guideline for biogas and biomethane. This methodology was developed with reference to leading clean fuel standards and biomethane Renewable Energy Certificate (REC) schemes within Canada, USA and Europe. Each international scheme has its own associated methodologies as shown below in the research references and explained further in the associated research document which informed this methodology for NZ[16]. Reference Appendix A for overview of international scheme references.

International biomethane caron footprint methodologies and models inform the Carbon Intensity (CI) of the fuel, which is the carbon emissions per unit of fuel. International methodologies have variations though all follow a life cycle assessment (LCA) approach. The key areas of variability within the CI models are the allocation method, system boundaries, assumptions, predefined default data, prescribed emission factors and timeframes. A gaseous biofuel CI is producer, scenario and model dependent; the fuel property changes over time depending on the supply chain and process to create the fuel.

This methodology aligns with similar principles of many of the international methodologies augmented with NZ specific requirements and fully aligned to ISO 14067 product carbon footprint requirements.

This gaseous biofuel product carbon footprint methodology provides guidance for assessing the carbon intensity[5] of the product and excludes the assessment of avoided emissions and related carbon credit generation. This complies with ISO 14067 Carbon Footprint of Products.

2.1. Scope

This methodology document covers the below system processes as they relate to gaseous biofuel production and GHG quantification.

1. Organic waste diversion to AD Plant gaseous biofuel
2. Landfill gas recovery to gaseous biofuel
3. Municipal wastewater treatment plant (WWTP) to gaseous biofuel

The scope of the methodology covers the full lifecycle carbon intensity (CI) of gaseous biofuel and the carbon footprint allocated to the coproducts of CO_2, digestate, heat and electricity.

The scope delineates the key lifecycle stages so they can be used for reporting purposes within an organisational carbon footprint where a renewable gas certificate is used. Measurement and

[5] Carbon Intensity and Product Carbon Footprint are used interchangeably within this document and are intended to mean the same thing.

verification best practice is highlighted in alignment with international standards. This methodology is intended to enable a gaseous biofuel Renewable Energy Certificate (REC) scheme within NZ.

2.2. Carbon Intensity and Functional Unit

Product carbon footprint methods develop a product carbon footprint relative to a functional unit of the product. Some clean fuel standards refer to this as carbon intensity (CI) of the fuel.

Product carbon footprint is underpinned by life cycle assessment (LCA). Life Cycle Assessment (LCA) is the compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product system throughout its life cycle (ISO 14040).

The global standard functional unit for biomethane is MJ or kWh of fuel energy based on the higher heating value (HHV). The carbon emissions per functional unit is typically CO_2e/ energy content of fuel. This is commonly expressed as gCO_2e/MJ, or its equivalent in magnitude kgCO_2e/GJ and is adopted for this methodology.

The energy density of gaseous biofuels is measured and calculated within this methodology and varies depending on the producer, feedstocks and a range of other producer specific variables.

The energy density of transmission pipeline specification biomethane must meet the NZ Specification for reticulated natural gas (NZS 5442:2024) and its required wobbe index and relative density limits which imply a calorific value range (energy density) of 35.2 MJ/m^3 – 46.5 MJ/m^3.

2.3. Emission factors

An greenhouse gas emission factor (EF) is a co-efficient that describes the mass of a greenhouse gas emitted relative to input or output of a unit process or a combination of unit processes. Suitable factors need to be selected for this gaseous biofuel CI calculation.

EFs should be full life cycle factors for an ISO 14067 product carbon footprint measurement. Full lifecycle EFs can be accessed from databases such as Ecoinvent which is the most widely used and comprehensive life cycle inventory databases in the world.

In some instances emission factors can be sourced from Ministry for the Environment (MFE) latest publicly accessible factors[6] where applicable. Caution needs to be applied when using these emission factors within this LCA carbon footprint methodology to ensure that the MFE EF's are applied to cover the lifecycle emissions of the source being quantified. MFE EFs are primarily for organisational carbon footprint which may not include the full lifecycle emissions. When emissions factors are not full LCA EF's (such as direct emission factor), the value should

[6] MfE Measuring Emissions: A guide for organisations: 2024 detailed guide

be supplemented with other relevant supply chain scope 3 emissions factors. Note the MFE EF for AD does not meet the requirements of this methodology for accuracy[7].

All practicable efforts to use the most accurate and representative emissions factors should be applied in alignment with the below hierarchy:

1. Full life cycle Supplier specific EFs from the supplier of a product or service.
2. Life cycle emissions factors from Ecoinvent where relevant.
3. Latest NZ MFE EF's where applicable
4. Other government published data for NZ
5. Industry specific studies

More guidance is available in the Toitū explainer on precision and accuracy in Appendix A.

Global Warming Potential (GWP) values from the latest IPCC Assessment Report from the shall be used where possible (currently 6th Assessment Report).

2.4. Treatment of GHG gases and biogenic CO_2

This methodology accounts for all relevant GHGs, including CO_2, methane (CH_4), and nitrous oxide (N_2O) in the emissions assessment. The individual GHGs shall be reported disaggregated prior to aggregating to a CO_2 equivalent. The total carbon footprint of the biofuel is aggregated to a Carbon Equivalent. CO_2 equivalent (CO_2e) is a metric used to standardize and quantify the global warming potential (GWP) of different greenhouse gases (GHGs) by expressing them in terms of the warming impact of carbon dioxide (CO_2).

The Global Warming Potential (GWP) is an index, based on radiative properties of GHGs, measuring the radiative forcing following a pulse emission of a unit mass of a given GHG in the present-day atmosphere integrated over a chosen time horizon, relative to that of carbon dioxide (CO_2). The GWP shall be based on a 100-year lifecycle and should be sourced from the latest MFE values AR5 /AR6 or IPCC report AR5/AR6 per table below.

Table 2: GWP of gaseous biofuel GHGs adapted from the latest IPCC values[8].

Greenhouse Gas	AR5 GWP-100 ($kgCO_2e/kg$)	AR6 GWP-100 ($kgCO_2e/kg$)
CO_2	1	1
CO_2 (biogenic)	0	0
CH_4(fossil)	30	29.8
CH_4(biogenic)	28	27.9
N_2O	265	273
Sulphur hexafluoride	23,500	24,300

[7] MFE Default AD factor is from 2006 IPCC, Ch. 4, Table 4.1. The factor makes assumptions on feedstock, DOC, and fugitives which make it usable for a product LCA.
[8] Canadian Clean Fuel Regulations: Specification for Fuel LCA Model CI Calculations, V3.0, 2024

Organic wastes including food waste, DAF sludge and wastewater sludge are considered renewable biogenic feedstocks for generating biofuel from biogenic decomposition. Organic waste contains biogenic carbon that is assumed to normally decompose via aerobic or anerobic decomposition and be released to the atmosphere. Methanogenesis is the final stage of anaerobic digestion, where microorganisms produce methane (CH_4) from intermediate compounds. Gaseous biofuel production collects the CH_4 from the methanogenesis cycle to use if for fuel. This guideline treats biogenic CO_2 emissions as zero because it would have been released to atmosphere via natural processes due to decomposition. This aligns to the approach of the IPCC[9] and organizational/ user emissions under ISO14064-1. This carbon neutral approach to gaseous biofuels combustion also aligns with the UK Green Gas Certificate Scheme by which the combustion of biogas and biomethane treat CO_2 emissions as zero. This treatment of directly combusted gaseous biofuels is due to their neutral status in the carbon cycle, as they are part of natural short cycle biological processes.

Users of gaseous biofuels shall not count the biogenic CO_2 emissions towards the carbon intensity, however it must be accurately calculated and reported separately in the LCA results and organizational inventory. All biogenic emissions other than CO_2, such as biogenic CH_4 and N_2O should be recorded within the carbon footprint of the user and product. This helps stakeholders understand the full scope of emissions associated with a product.

Based on the net zero aspect of biogenic CO_2, switching to gaseous biofuel is a potent emission reduction option for switching from fossil gas. Across the lifecycle biomethane has an approximately 60-65% reduction of emissions relative to fossil gas due to the near zero emissions of biomethane combustion.

For further reading on the application of biogenic emissions in organization carbon accounting, see Toitū's explainer[10].

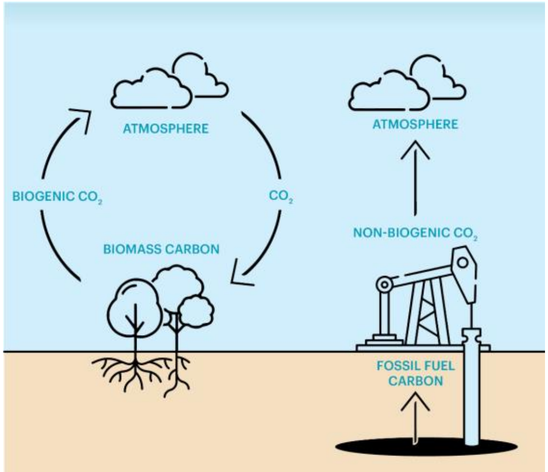

Figure 1 Short Term Biogenic Cycle vs. Long Term Fossil cycle[10]

[9] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 3 on Solid Waste Disposal, methane recovery. pg. 3.18

[10] Explainer Series | Why Biogenic emissions matter | Toitū Envirocare (toitu.co.nz)

2.5. Renewable Feedstock

This methodology only allows for biogenic waste feedstock to produce gaseous biofuel and excludes energy crops[11] from its scope. Waste is herein defined as a substance which the owner intends or is required to dispose of in alignment with ISO 14067.

Waste feedstock shall align with the EU RED Cert[12] scheme principles feedstock for sustainable biofuels. To ensure the biogenic feedstock is renewable and sustainable it shall meet the definition of biogenic waste in the below flowchart below adapted from the EU REDCert:

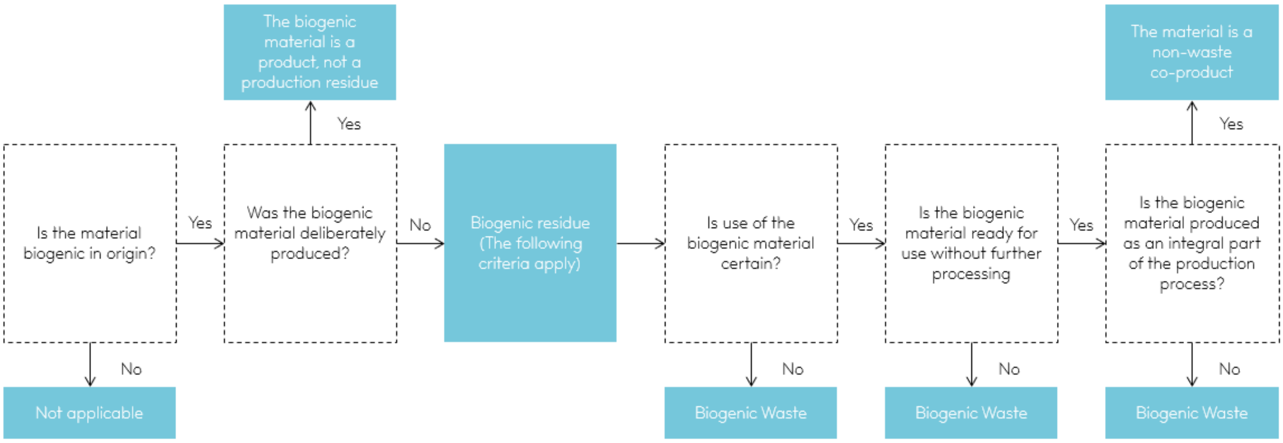

Figure 2: Flowchart to ensure Sustainable Biogenic Waste Feedstock

Renewable organic/biogenic waste feedstocks included in this methodology are:

1. Municipal, industrial and commercial wastewaters or sludges,
2. Organic component of municipal solid waste (separated at source or prior to landfill),
3. Waste from food production and agriculture e.g. crop residues, horticultural waste, agriculture byproducts,
4. Food and beverage processing waste,
5. Food waste from retailers, distributors, consumers (including hospitality, government, institutions, companies etc),
6. Vegetative matter (including garden waste), and timber waste,
7. Animal waste, specifically (but not limited to) agricultural waste.

2.6. Temporal Boundary

A gaseous biofuel CI is producer, scenario and model dependent; the fuel property changes over time depending on the feedstock, supply chain and process to create the fuel.

[11] Energy crops are plants grown for the purpose of producing biofuels.
[12] REDCert, Scheme principles for the production of biomass, biofuels, bioliquids and biomass fuels

All material (significant) activity data relevant to the gaseous biofuel system boundary shall be collected and on an annual basis. Gaseous biofuel carbon intensity shall be calculated on an annual basis.

Verification is the process of evaluating a GHG claim with past historical data to determine it is materially correct and conforms to predetermined criteria. This is typically done annually by international REC schemes and Low Carbon Fuel Standards such as International REC scheme (I-REC), California Low Carbon Fuel Standards and EU RedCert.

This guidance document does not mandate a verification frequency but instead stipulates a critical peer review of the LCA in alignment with

2.7. System Boundary

The system boundary is a key concept in life cycle assessment (LCA) and associated product carbon footprinting. The system boundary is the boundary based on a set of criteria representing which unit processes are a part of the system under study.

Figure 4 shows two system boundaries for this methodology. This methodology provides the system boundary for the **Cradle to Gate** and **Cradle to Grave** carbon intensity of the gaseous biofuel product. Cradle-to-gate defines the scope of a carbon LCA which covers all life cycle stages up to the production facility gate. Cradle-to-grave defines the scope of a carbon LCA which covers the full life cycle including end use combustion emissions of the gaseous biofuel.

This methodology covers both system boundaries which aligns with the requirements of many of the biomethane certification schemes internationally. The Canadian Clean Fuel Regulations scheme require reporting of both boundaries, EU REDCert require cradle to grave, and the World Biogas Association require cradle to gate. The system boundary includes upstream inputs of organic waste products and all material activities, inputs and outputs of anaerobic digestion and subsequent refinement of biogas to biomethane. Further details on activities included in the system boundary are found in later sections and Figure 10 – Biogas / Biomethane Process Flows example inputs and outputs.

Producers of gaseous biofuel shall report the Cradle to Gate product carbon footprint. The LCA gate is at the pipeline network, post biogas scrubbing, compression and injection into the pipeline network. Gate to grave emissions includes transmission and combustion of the gaseous biofuel which happens outside of the control and influence of the producer.

Users of gaseous biofuel require full cradle to gate and gate to grave emissions assessment for an organisational compliant GHG inventory to ISO 14064-1. Cradle to gate emissions satisfies user emissions reporting indirect emissions of the fuel and is often referred to as upstream well to tank or well to wheel emissions (GHG Protocol, Scope 3, Category 3).[13].

[13] Corporate Value Chain (Scope 3) Accounting and Reporting Standard

Gate to grave emissions include direct emissions from combustion of the gaseous biofuel and indirect emissions from transmission and distribution (T&D) losses in the pipeline network. Combustion emissions satisfy user emissions reporting direct emissions (GHG Protocol, Scope 1). T&D emissions satisfy user emissions reporting GHG Protocol, Scope 3, Category 3 indirect emissions.

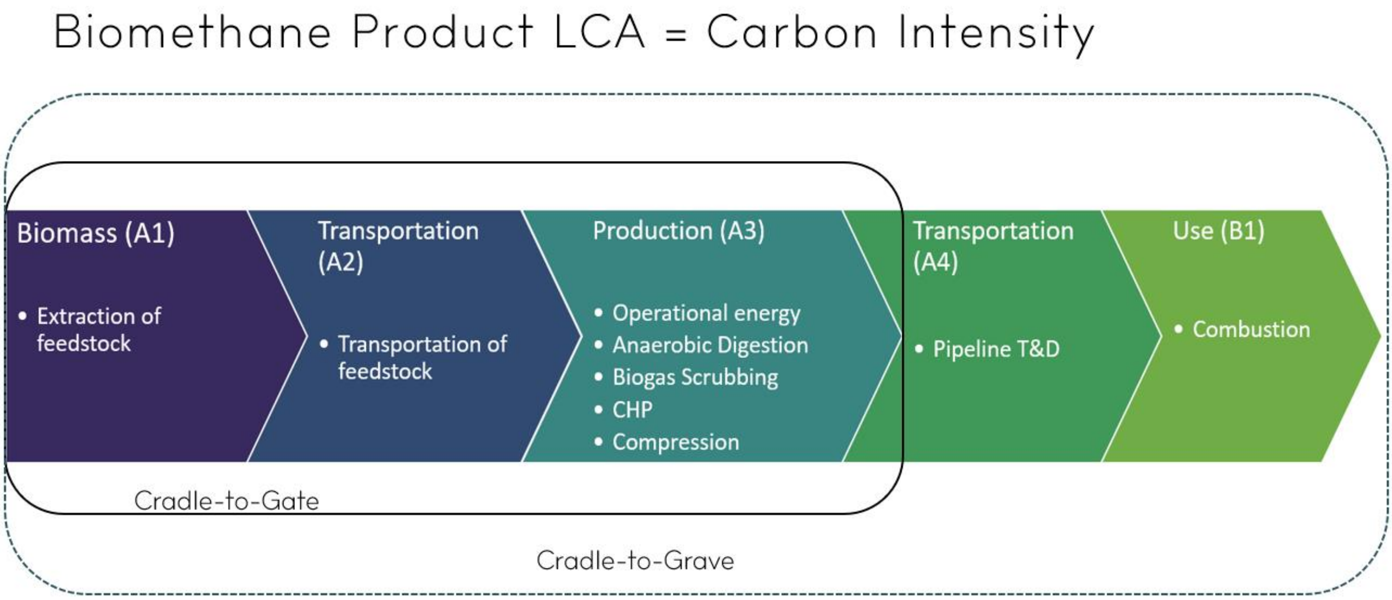

Figure 3 – System boundary, cradle to gate and cradle to grave

2.7.1. Food / Organic Waste to AD - System Boundary:

One of the three system processes detailed in this methodology is the organic waste to AD gaseous biofuel project. The AD project diverts organic waste from its current/ business as usual (BAU) end use waste processes (e.g. landfill) assumed to be in a different geographical location.

The AD project diverts organic waste to use as feedstock for gaseous biofuel production. Baseline emissions are the business-as-usual treatment of the organic waste (see Figure 5). The food / organic waste project emissions are the actual GHG emissions that occur within the system boundary after the installation of the biogas control system (BCS).

Figure 5 highlights the various alternative organic waste treatment process that may represent baseline / (BAU) relative to the Anaerobic Digestion process. The dotted lines show the BAU waste treatment process with the solid line showing the AD project highlighting the upstream system boundary. This is relevant for understanding the upstream system boundary of the gaseous biofuel CI calculation.

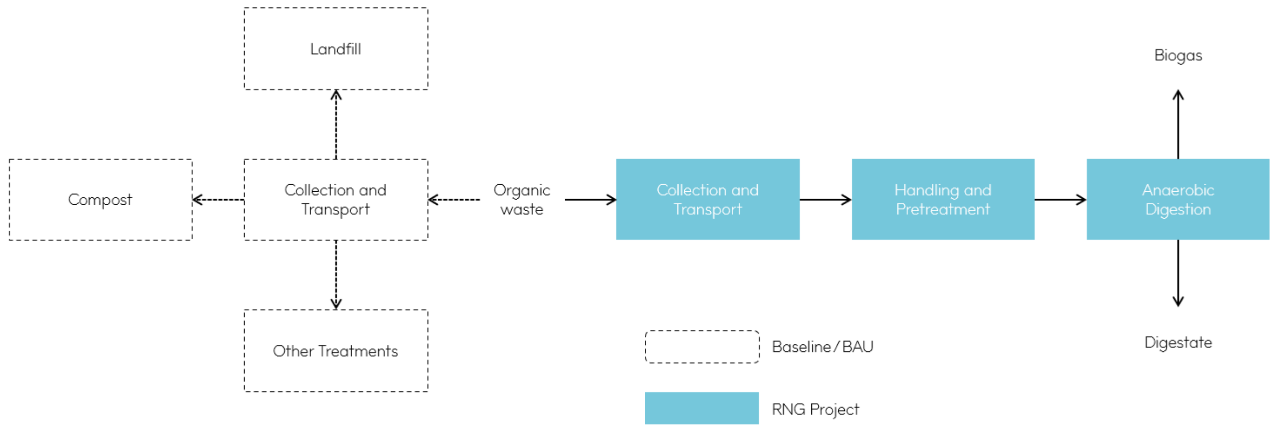

Figure 4: Food / Organic Waste Diversion to AD, Upstream System Boundary vs. Baseline Scenario[14]

Figure 5 above shows that organic waste collection and transport would be accounted for in the BAU and the gaseous biofuel Project CI. Table 3 below shows the upstream sources that would be included in the gaseous biofuel CI calculation.

Table 3: Upstream GHG Sources Included or Excluded from the Food Waste to AD Project Boundary

Source	Emission Source	Gas	Included/ Excluded	Justification
AD Plant Construction	Embodied Emissions	CO_2, CH_4, N_2O	Excluded	Global Methodologies exclude embodied emissions from plant construction. Deemed de minimis and outside LCA boundary[15].
Feedstock Production	Fossil fuel consumption	CO_2, CH_4, N_2O	Excluded	Feedstock is a waste product and therefore emissions for production are zero as this is an end of life recovery / reuse process.
BAU Feedstock Collection + Processing	Energy /Fossil fuel Consumption, Fugitive emissions	CO_2, CH_4, N_2O	Excluded	Kerbside Collection excluded. Transportation to current waste sorting facility under BAU is excluded. Emissions from landfill excluded unless associated to the development of Gaseous Biofuel.
Feedstock Collection	Energy /Fossil fuel consumption	CO_2, CH_4, N_2O	Included	Project activity requires Feedstock collection from BAU point of collection.

[14] Carbon Accounting Methodology for Biogas, American Biogas Council, DRAFT 1.0 — March 8, 2024
[15] World Biogas Association notes that more work and consideration is needed here by certification bodies.

Source	Emission Source	Gas	Included/ Excluded	Justification
Feedstock Transportation	Energy / Fossil fuel consumption	CO_2, CH_4, N_2O	Included	**Included –** The waste is transported to a different site than in the baseline.
Feedstock Processing	Facility energy/fossil fuel consumption	CO_2, CH_4, N_2O	Included	Includes all processing emissions for biogas / biomethane.

Diversion of food waste from a higher emissions BAU scenario to AD can reduce emissions in the broader economy. Quantifying the GHG emissions avoided by using an alternative solution such as AD derives a metric known as the avoided emissions. Avoided emissions are defined as the "positive" impact on society when comparing the GHG impact of a solution to an alternative baseline reference scenario. Avoided emissions are reductions beyond the gaseous biofuel Carbon Intensity / footprint based on ISO 14067 product carbon footprint standard. Avoided emissions are part of the Net emissions impact of a project and are often quantified to enable carbon credits and as a key metric for Green Bonds.

Aligned with UK Green Gas Certification, World Biogas Association Methodology and EU REDCert standards avoided emissions are included in this method for calculation of gaseous biofuel CI. Some international methodologies require calculation of the avoided emissions such as the California GREET and the American Biogas Association methodologies where there are Carbon Credit schemes in place for RNG projects. The Environment Canda Fuel LCA Methodology optionally allow for the calculation of avoided emissions which can produce a net emissions of the RNG (often a negative emissions).

Biofuel producers will need to calculate avoided emissions if they wish to use the activity to create carbon credits aligned with international standards like the International Council of Voluntary Carbon Markets (ICVCM). More on avoided emissions can be found in the literature review[16] research document underpinning this methodology development.

2.7.2. Landfill Gas System and Boundary:

The second of the three system processes defined in this methodology is the landfill gas (LFG) to gaseous biofuel project. The LFG to gaseous biofuel project diverts LFG from its current/ business as usual (BAU) state to gaseous biofuel.

Landfill gas bioenergy projects are defined as projects that capture landfill Gas (LFG) from the anaerobic decomposition of municipal solid waste (MSW).

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[16] Toitū, Literature Review – Methods for accounting for the Carbon Intensity of Biomethane, Rev.1

Landfill gas baseline emissions are the most likely BAU treatment for landfill gas prior to the biofuel project. In Figure 7 below you can see the common BAU landfill gas process that could be considered (eg. flaring or venting to atmosphere). In Figure 6: MFE Landfill Types in NZ, below the BAU situation prior to gaseous biofuel production.

Landfill type	Description
Municipal (class 1) landfills with gas recovery	Municipal, well-managed landfill where a landfill gas recovery system is installed. Some of the CH_4 produced during the organic decomposition of waste is captured and destroyed.
Municipal (class 1) landfills without gas recovery	Municipal, well-managed landfill where all the CH_4 produced during organic decomposition of waste escapes into the atmosphere, apart from that which is oxidised inside the landfill.
Non-municipal (class 2-5) landfills	Non-municipal landfills that accept a broader range of wastes where the CH_4 produced during organic decomposition of waste escapes into the atmosphere.

Figure 5: MFE Landfill Types in NZ[17]

The below image shows that LFG to gaseous biofuel projects typically exclude the kerbside collection, transport to landfill, landfill fugitive, venting and flaring emissions from the gaseous biofuel CI. Any additional energy and emissions required to convert the LFG from BAU to the gaseous biofuel is within the upstream boundary of the gaseous biofuel CI. Table 4 below shows the common upstream emissions sources within the gaseous biofuel CI calculation for landfills.

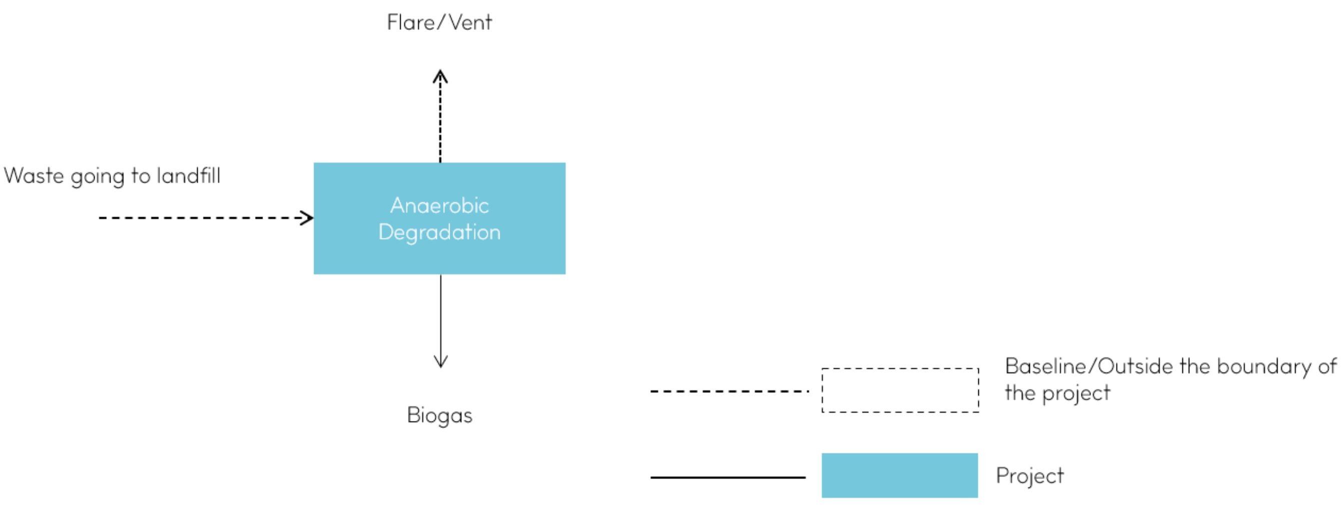

Figure 6: LFG to gaseous biofuel Project Upstream Boundary vs. Baseline/BAU

[17] MFE, Technical Guidelines for the Disposal to Land - Project Team Draft - Revised B, MfE comments

Table 4: Upstream GHG Sources Included or Excluded from the LFG gaseous biofuel Project Boundary

Source	Emission Source	Gas	Included/ Excluded	Justification
AD Plant Construction	Embodied Emissions	CO_2, CH_4, N_2O	Excluded	Global Methodologies exclude embodied emissions from plant construction. Deemed de minimis and outside LCA boundary[18].
Feedstock Production	Fossil fuel consumption	CO_2, CH_4, N_2O	Excluded	Feedstock is a waste product and therefore emissions for production are zero as this is an end-of-life recovery / reuse process.
BAU Feedstock Collection + Processing	Fossil fuel / energy Consumption, Fugitive emissions	CO_2, CH_4, N_2O	Excluded	Landfill waste and landfill gas is assumed to be produced regardless of gaseous biofuel project. Fugitive emissions are excluded unless associated to the development of Gaseous Biofuel.
Feedstock Transportation	Fossil fuel consumption	CO_2, CH_4, N_2O	Excluded	Landfill waste and landfill gas is assumed to be produced regardless of gaseous biofuel project
LFG Processing	Landfill energy consumption	CO_2, CH_4, N_2O	Included	Includes all processing emissions for LFG to biogas / biomethane.

2.7.3. Wastewater Treatment Plant Boundary:

The third system processes defined in this methodology is the Wastewater Treatment Plant (WWTP) to gaseous biofuel project. The WWTP to gaseous biofuel project diverts the plants sludge from its current/ business as usual (BAU) process to gaseous biofuel production at the same geographical site.

On the WWTP, biogenic methane (CH_4) is generated through the conversion of organic matter by the process of methanogenesis. This process can occur in the solids removed from the water supply during water treatment, and from the organic matter found in wastewater and removed in its treatment process. This is part of the BAU process of the WWTP and is excluded from the upstream boundary of the gaseous biofuel CI.

Biogenic nitrous oxide (N_2O) occurs as the product of denitrification and/or nitrification of the nitrogen compounds found in wastewater by microorganisms, including as part of the treatment process itself. The major sources of biogenic methane and nitrous oxide in the wastewater

[18] World Biogas Association notes that more work and consideration is needed here by certification bodies.

network are illustrated in below Figure 8. All of these BAU process of the WWTP are excluded from the upstream boundary of the gaseous biofuel CI.

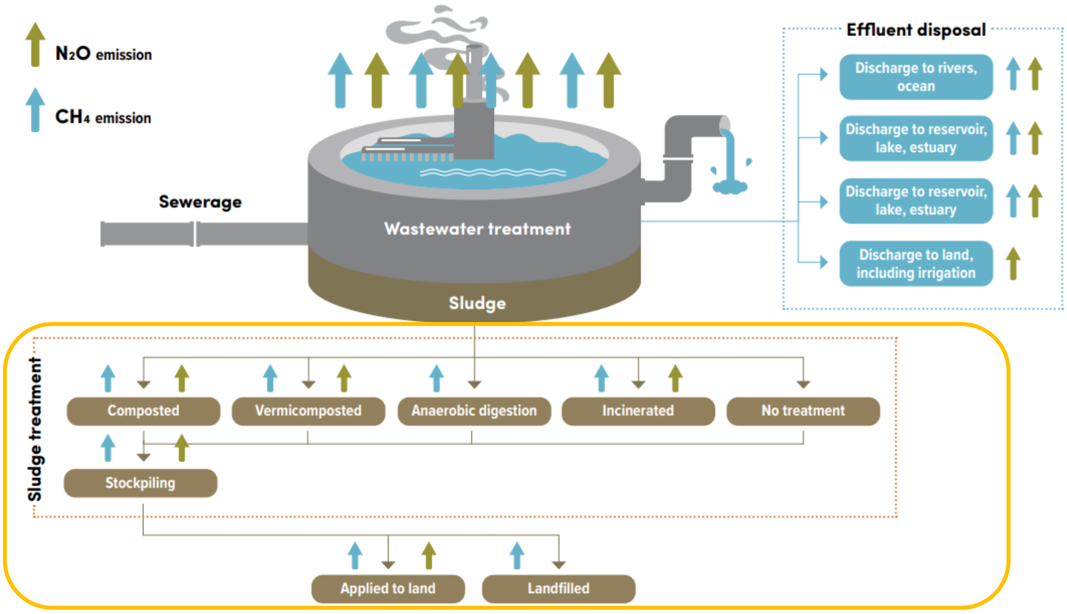

Figure 7 – Navigating to Net Zero, Water NZ, Wastewater emissions.[19].

Figure 9 shows the upstream boundary between the BAU WWTP treatment and an AD plant installed on the same site. In this system process, the gaseous biofuel CI excludes the BAU energy and emissions of the WWTP plant to treat the sludge and send the sludge to the onsite AD. Any additional energy and emissions over and above BAU required for the AD facility to process the gaseous biofuel onsite becomes the upstream boundary of the LCA. Table 5 below shows the common upstream emissions sources included within the gaseous biofuel CI calculation.

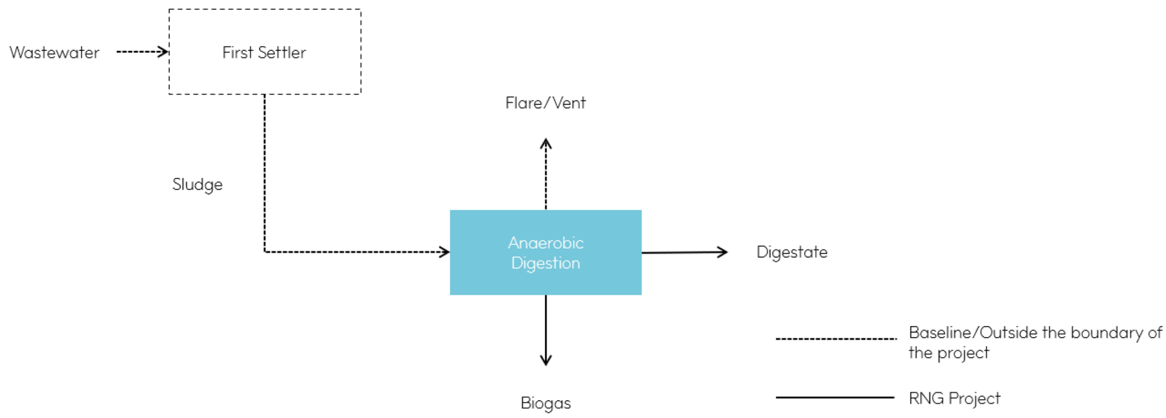

Figure 8 WWTP AD Project for Treatment of Sludge showing upstream project boundary.

[19] Water NZ published *Accounting Guidelines for Wastewater Treatment*

Table 5: Upstream sources included or excluded from the Wastewater gaseous biofuel Project Boundary

Source	Emission Source	Gas	Included/Excluded	Justification
Embodied	Carbon footprint of building AD infrastructure.	CO_2e	Excluded	Global Methodologies exclude embodied emissions from plant construction. Deemed de minimis and outside LCA boundary[20].
Feedstock Production	Fossil fuel Consumption, Fugitive emissions	CO_2, CH_4, N_2O	Excluded	Feedstock is a waste product and therefore emissions for production are zero as this is an end of life recovery / reuse process.
BAU Feedstock Collection + Processing	Electricity /Fossil fuel Consumption, Fugitive emissions	CO_2, CH_4, N_2O	Excluded	Emissions related to the collection and processing of the feedstock prior to AD project are excluded unless they are associated to the development of Gaseous Biofuel.[21]
AD Feedstock Collection	Electricity /Fossil fuel consumption	CO_2, CH_4, N_2O	Included	Emissions related to the collection of the sludge feedstock for AD facility. e.g. pumps and equipment
Feedstock Transportation	Fossil fuel consumption	CO_2, CH_4, N_2O	Excluded	Wastewater treatment is assumed to be sourced from the same location in the baseline and project.
Sludge AD Processing	WWTP energy consumption and fugitive emissions.	CO_2, CH_4, N_2O	Included	Includes all processing emissions for sludge to biogas / biomethane.

[20] World Biogas Association notes that more work and consideration is needed here by certification bodies.
[21] Decrease in emissions from BAU based on the AD project are considered Avoided Emissions and outside of the LCA CI of the biofuel. For more info see research document.

3. PROCESS FLOWS AND ACTIVITY DATA:

ISO 14067 requires that the gaseous biofuel CI methodology define consistent criteria for:

1. Which unit processes require a detailed assessment is needed due to an expected significant contribution to the carbon footprint;
2. Which unit processes the quantification of GHG emissions may be based on secondary data if the collection of primary data is not possible or practicable;
3. Which unit processes may be aggregated,

All process flows within the CI system boundary are to be included where they are material.

Within this methodology, materiality is a word to describe if a GHG source or sink is significant enough to include in the gaseous biofuel CI. A source is material if it is of significant magnitude (>1%). An emissions source is also material if it is less than 1% in magnitude and the producer has an ability to measure and influence those emissions. A source or sink can also be material if it is significant to the sector or key stakeholders of the GHG information.

If a GHG source from a process flow can be demonstrated to be immaterial (de minimis) compared to the overall footprint (less than 1% of total[22]), that flow may be excluded. The effect of any exclusions on the outcome of the assessment shall be included in the gaseous biofuel product carbon footprint report. The total of the sources classified as immaterial or de minimis shall not exceed 5% of the total gaseous biofuel carbon footprint.

Figure 10 is an example of the types of process flow inputs and outputs considered and measured as part of the gaseous biofuel system LCA.

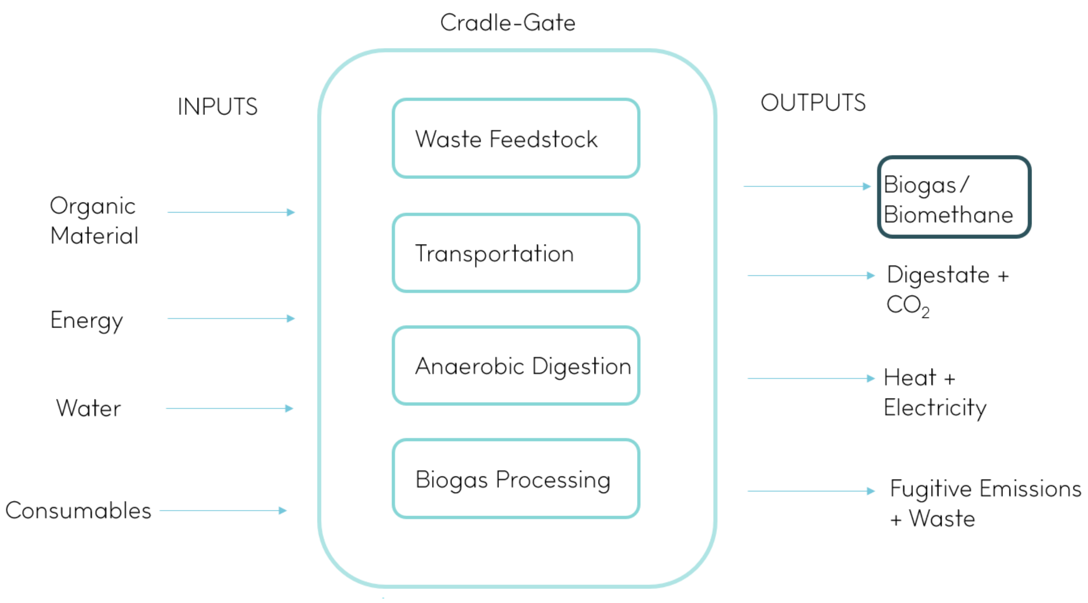

Figure 9 – Biogas / Biomethane Process Flows example inputs and outputs.

[22] ISO 14044 LCA

3.1. Mass Balance:

Mass balance is a key concept in gaseous biofuel CI accounting for producers. It ensures accurate tracking and reporting of emissions throughout the production process.

Mass balance is based on the law of conservation of mass; that the mass entering a system must equal the mass leaving the system plus any accumulation within the system over a specified period. This is expressed mathematically as:

$$\text{Mass In} - \text{Mass Out} = \Delta\ \text{Storage}$$

The primary goal of mass balance is to ensure that all material flows are accounted for, providing a check on the validity and completeness of the data. It helps in identifying discrepancies and ensuring that the system is accurately represented.

Producers must collect activity data on all material flows, including biomass inputs, biogas outputs, and any co-products, by-products or waste streams.[23]

The mass balance system must include both,

1. Information on the input/output of raw materials and fuels for which the above sustainability characteristics have been determined (sustainably certified raw materials and fuels), and,
2. Information on the input/output of raw materials and fuels, including fossil fuels, for which no sustainability characteristics have been determined.

3.2. Activity Data Requirements

Once the material / mass inputs and outputs to the gaseous biofuel system are defined key activity data must be measured or estimated in a transparent and comprehensive manner.

Activity data in GHG accounting is defined as the quantity of an emitting activity being measured, for instance the kWh of electricity used to power a process. Activity data quality should always be prioritised for the most material emissions sources within the system boundary.

Activity data is categorised as primary or secondary data, and the category into which it falls disclosed.

1. **Primary data is defined as the quantified value of a process or an activity obtained from a direct measurement, or a calculation based on direct measurements.** For instance, kWh of electricity purchased, measured at meter.
2. **Secondary data is defined as data which do not fulfil the requirements for primary data. Secondary data can include data obtained from proxy processes or**

[23] REDcert EU - Scheme principles for GHG calculation - Version EU 06, 2023

estimates. For instance, using spend data to estimate emissions of a quantity of purchased consumables or using average sector default values for fugitive emissions.

All material Activity Data should be peer reviewed.

Key GHG sources, activity data units/metrics and data quality are presented in Table 6. Emission Factor sources and defaults are provided through the calculations and summarised in Appendix B.

Table 6: Gaseous Biofuel GHG Activity Data and Data Quality

Life cycle stage	Parameter / GHG source	Activity Data unit	Primary or Secondary	Activity Data source	EF source / Default
Waste feedstock extraction	Waste Input per waste type eg. food waste, DAF sludge, WWTP Sludge. Report percentage of degradable organic carbon (DOC) and percentage total solids / dry solids.	kg, DOC, %DS	Primary (based on actual formulation)	Project/ Site specific	DOC Table 5 Calculated
Waste feedstock transportation	Road freight	L fuel / or t.km	Primary / secondary	Freight fuel use; alternatively Feedstock Weight and distance travel	MFE direct fuel use + WTT indirect emissions21F[24]
Biogas Processing (Indirect emissions)	Chemicals	kg or $	Primary or Secondary	Site Records or expenditure	Ecoinvent
	Electricity used from grid	kWh	Primary	energy invoices	MFE location based EF
	Consumables	kg or $	Primary or Secondary	Site Records, expenses	Supplier specific or Ecoinvent, MFE
Biogas Processing (Direct emissions)	Fugitive emissions	m^3 gas	Primary or Secondary		default fugitive emissions 1% Table 10

[24] Agrilink, NZ Fuel and Electricity – Total Primary Energy and GHG Emission Factors 2022

Life cycle stage	Parameter / GHG source	Activity Data unit	Primary or Secondary	Activity Data source	EF source / Default
Biogas Processing (Direct emissions)	Digester Leakage	m^3 gas	Primary or Secondary	Site Measurements preferable	default fugitive emissions 1%
	Flaring / Combustion	m^3 gas	Primary	Flare Flow control	MFE
	Digestate storage and Lagoons	m^3 CH_4	Primary or Secondary	input rate of volatile solids (VS) measured monthly	Calculated per Equation 13 Default: 0.48 m^3 CH_4/kg VS
	Combined Heat and Power (CHP), heat and electricity cogeneration on production site	GJ fuel, CI fuel, efficiency	Primary	Site specific	Calculated per plant22F[25] see Equation 7: CHP GHG
	Diesel / Fossil Fuels	Litres		Site Records	Ecoinvent / Agrilink
Biomethane scrubbing and compression	**Covered in onsite energy use**				
Waste	Waste	kg	Primary	Site Records	Zero Carbon based on Biogenic LCA
CO_2 Gas	Co-product	m^3	Primary	Site Records	Biogenic CO_2 - zero carbon product
Digestate	Co-product	kg	Primary	Site Records	zero carbon product
Digestate Application	**Excluded based on energy allocation and beyond LCA boundary**				
RNG distribution	at gas pipeline pressure and specification	GJ	Primary	RNG volume	MFE T&D loss
RNG combustion	Biogenic combustion	GJ	Primary	user GHG inventory	per ISO 14064-1, MFE

[25] Environment and Climate Change Canada, Fuel life cycle assessment model methodology, CI of the electricity and thermal energy produced by the CHP system per section A4.

3.3. Exclusions

This methodology prioritises energy and material inputs that are part of the life cycle of a fuel, including the emissions associated with the production and the use of its inputs. From these inputs and emissions, only significant contributors to the CI of fuel are considered.

The following processes and activities are excluded from the methodology due to their negligible contribution or limitations such as lack of data, methods or high uncertainty or outside of the system boundary.

Table 7: GHG source exclusions for the RNG CI

Exclusion	Justification
Construction and decommissioning of equipment and facilities	Excluded from all the international methodologies researched. Outside of system boundary.
Indirect land use change from construction of facilities.	Excluded from all the international methodologies researched. Outside of system boundary.
The manufacturing of fuel transportation infrastructure (i.e., pipelines, trucks, ships, roads)	Outside of system boundary.
The manufacturing of fuel combustion infrastructure (i.e., vehicles, boilers)	Outside of system boundary.
Solid waste management processes and wastewater treatment processes in the business-as-usual scenario. Kerbside collection and Landfill fugitive emissions and wastewater processing are excluded.	Outside of system boundary based on the BAU situation prior to biomethane project
Indirect activities associated with fuel production, such as marketing, accounting, commuting, and legal activities	Assumed to be de minimis
Digestate application to land & CO_2 use	use phase of co-products is outside of cradle to gate system boundary for biomethane.

4. GASEOUS BIOFUEL CI CALCULATION METHODOLOGY

To calculate the carbon intensity of biogas/ biomethane several key activity data metrics are essential as described in previous sections. These metrics help in performing a comprehensive life cycle assessment (LCA) to quantify greenhouse gas (GHG) emissions associated with production to calculate a product carbon footprint. The calculations and metrics for this RNG CI calculation methodology are described below. **Some of the variables will require further detailed calculations to cover the specifics of the system process and variables of the producer. It is the intention that this formula will provide overall coverage of the product emissions sources with detailed nuances to be determined by the producer.**

4.1. Gaseous Biofuel Cradle to Gate Carbon Intensity Calculation

Cradle-to-gate: scope of a carbon intensity which covers all life cycle stages up to the production facility gate. Below Equation 3,Equation 4, Equation 5 are adapted from EU REDcert methodology.

Equation 1: $CI_{biofuel} = PE \div (V_{biofuel} \text{ x } Ed_{biofuel})$

CI = Carbon Intensity of gaseous biofuel (kgCO2e/GJ)
PE = Annual total production emissions of gaseous biofuel (Cradle to Gate) (kgCO2e)
$V_{biofuel}$ = Volume of gaseous biofuel produced for the annual period at atmospheric pressure and temperature (m3)
$Ed_{biofuel}$ = Energy density of gaseous biofuel; (GJ/m3)
Ed_{biogas} / Ed_{BM} = %CH4 x 0.0358 (LHV of CH4, GJ/m3)

Equation 2: $PE = F+CE + EU + FE_T + CU+W$

PE = Annual total production emissions of gaseous biofuel (Cradle to Gate) ($kgCO_2e$)
F = Feedstock Emissions
CE = Combustion Emissions
EU = Electricity Use Onsite
FE_T = Fugitive Emissions
CU = Consumables Used Onsite
W = Waste Emissions

4.2. Feedstock Emissions

Feedstock emissions are considered those emissions associated to the extraction process and transportation of the feedstock to the gaseous biofuel system. The feedstocks of the gaseous biofuel is the renewable organic waste diverted from other processes.

This formula allows for various feedstocks (S_x) to be aggregated into an overall feedstock emissions (F).

Equation 3: $F = \sum S_x (E_x + T_x)$

F = Feedstock Emissions ($kgCO_2e$)
S_x = Share of feedstock ***x***, mass of feedstock input to the digester. (kg)
E_x = Emissions from the extraction of the feedstock **x**. ($kgCO_2e/kg$)
T_x = Emissions from transport of feedstock **x** to gaseous biofuel system. ($kgCO_2e/kg$)

4.2.1. Feedstock Transportation (Tx)

Feedstock transportation should be addressed in a consistent manner within the LCA.

Transportation emissions shall include well to tank and tank to wheel emissions assessment. Well to tank emissions are the upstream indirect emissions from the fuels extraction, processing and transport to the fuel tank/pump location. Tank to wheel emissions are the direct emissions from the use of the transportation fuel within the vehicle (eg. Combustion of fuel or direct use of electricity). The figure below shows this.

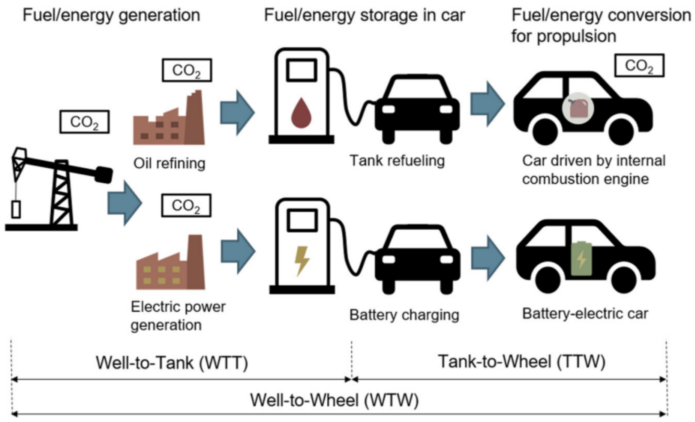

Figure 10: Well to tank vs Well to Wheel emissions.[26]

It should be noted that MFE emissions factors do not include well to tank indirect upstream emissions from fuels. For well to tank emissions factors see Appendix B.
Transportation tank-to-wheel emissions can be calculated in multiple ways as listed below in order of highest accuracy,

1. **Fuel-based method(recommended)**: Litres of fuel consumed (by fuel type), for feedstock transportation,
2. **Distance-based method (not recommended)**: requires km or Tonne-km data, by freight mode (road, rail, sea, air) and vehicle type for all freight,
3. **Spend-based method (not acceptable)**: requires spend data by freight mode.

The fuel-based method is most accurate and is the recommended approach of this methodology. Fuel should be measured and allocated by the transportation supplier based on the freight mass and distance travelled. If the transportation supplier is optimizing efficiency and using backloading then applying the fuel method will be most accurate when allocating a discounted portion of the fuel to the backload. In the fuel-based method, the capacity and intensity of fuel consumption of the vehicle may vary based on the loading. Therefore, to determine the amount of fuel used, data can be obtained from fuel purchase records instead of direct fuel measurement.

The distance based tonne-km method can be estimated based on the mass and distance of the feedstock transportation. MFE provide a long-haul heavy truck ton-kilometer (tkm) emission factor that is NZ specific and includes an industry wide allocation of empty return trips within the emissions factor. This factor is useful when the feedstock is a portion of the freight and there is no fuel data available.

The spend based method shall not be used for the upstream and direct transportation emissions. Spend based method uses $ spend activity data and is an industry average emissions intensity per $ based on EEIO data (economic environmental input output

[26] World Electr. Veh. J. 2022, 13, 61

tables). Spend based method is generally unacceptable for an LCA calculation based on its high level of uncertainty.

4.3. Combustion Emissions (CE)

Processing of biogas and biomethane generates direct and indirect emissions.

Direct emissions:

Direct emissions are created from combustion of fuels onsite to generate heat and power. Combustion of biogas on site for parasitic load can significantly reduce emissions from using fossil gas.

(CE) Combustion Emissions: Emissions from burning biogas or other fuels, measured in kilograms of CO_2 equivalent (CO_2e). Combustion emissions is typically calculated from use of fuel and heat.

1. **Fuel Use**: The quantity of fuels used (e.g., diesel for machinery), measured in litres (l) or kilograms (kg).
2. **Heat Use**: The amount of heat energy used, measured in megajoules (MJ) or gigajoules (GJ).
3. **Fugitive emissions**: from incomplete combustion as explained for CHP below.
4. **Combustion EF**: The emission factor for the combustion of the fuel. See Section 4.4 and 4.5 for Biogas and Biomethane combustion EFs.

4.3.1. Biogas Combustion Emissions (CE_{biogas})

This methodology acknowledges that some producers may utilise and sell biogas to end users without upgrading to biomethane. This calculation acknowledges that Biogas can vary in energy density and carbon emissions from combustion. The biogas properties, such as percentage of methane, temperature and pressure effect the energy density and carbon emissions the combustion.

Equation 4 $$CE_{biogas} = Ed_{biogas} \times V_{bg} \times (EF_{BM}) \ [KG\ CO_2e]$$

Ed_{biogas} = Energy density of biogas $\%CH_4$ / 99% × HHV_{BM} (GJ / m^3)
V_{biogas} =Total volume of biogas generated (m^3).
$\%CH_4$ = Methane Content, the percentage of methane in the biogas,
HHV_{BM} = Biomethane 0.0393 GJ/m^3 (@ 99% CH_4@ 101.3kPa, 15℃)
EF_{BM} = Biomethane emissions factor 0.13 Kg CO_2e / GJ Table 8

4.3.2. Biomethane Combustion Emissions (CE_{BM})

Biomethane refinement includes scrubbing the gas of contaminants such as H_2S and CO_2 to achieve pipeline specification gas. This calculation acknowledges that Biomethane can vary in energy density and carbon emissions from combustion. Biomethane can be consumed at the production site or by a customer via pipeline. The pressure of the gas effects the energy density and should be converted to standard temp and pressure for comparability 15℃, 101.3kPa. Combustion emissions for Biomethane can be calculated below:

Equation 5 $CE_{BM} = Ed_{BM} \times V_{BM} \times (EF_{BM}) \, [KG \, CO_2e]$

Ed_{BM} = Energy density of biomethane %CH4 / 99% × HHV_{BM} (GJ / m3)
V_{BM} =Total volume of biomethane generated (m^3).
%CH4 = Methane Content, the percentage of methane in the biogas,
HHV_{BM} = Biomethane 0.0393 GJ/m^3 (@ 99% CH_4@ 101.3kPa, 15℃)
EF_{BM} = Biomethane emissions factor 0.13 Kg CO_2e / GJ Ref. Table 8

4.3.3. Site generated Combined Heat and Power (CHP)

On site biogas can be used to generate heat and electricity (cogeneration) reducing the overall carbon intensity. The energy from biogas combustion is converted to mechanical energy by internal combustion engines and / or gas turbines. Electricity is produced, which can be used onsite. Waste heat can be recovered from exhaust gas and engine cooling systems. Factors impacting emissions include the type of CHP system, such as Internal combustions engines or Gas turbine. Along with the fuel content used (i.e. Biogas (50-70% CH_4) and Biomethane (95-99% CH_4) where the calorific value ranges between 35.2 MJ/m^3 – 46.5 MJ/m^3 reflective of CH_4 content).

Equation 6:[27]

$$CHP_{GHG} = \left[\frac{Ed_{biogas} + V_{biogas} + EF_{biogas}}{\eta_{elect}}\right] + \left[\frac{Ed_{biogas} + V_{biogas} + EF_{biogas}}{\eta_{heat}}\right]$$

Ed_{biogas} = %CH_4 /99% × HHV_{BM}
HHV_{BM} = Biomethane 0.0393 GJ/m^3 (@ 99% CH_4@ 101.3kPa, 15℃)
V_{biogas} = Volume of biogas (@ 101.3kPa, 15℃) combusted (m^3)
EF_{biogas} = Combustion Emissions Factor of biogas (kg CO_2/ GJ)
EF_{biogas} = %CH_4 /99% x EF_{BM}
EF_{BM} = 0.13 Kg CO_2e / GJ (@ HHV_{BM}, 99% CH_4, 101.3kPa, 15℃)
η_{heat} = Heat / Thermal efficiency - %
η_{elect} = Electricity conversion efficiency - %
Key variables that effect the emissions from CHP systems are:

1. Type of CHP system: ICE vs. Gas turbine
2. Fuel: Biogas (50-70% CH_4) and Biomethane (95-99% CH_4) calorific value range of 35.2 MJ/m^3 – 46.5 MJ/m^3 are much lower carbon intensity then fossil fuel (see table below)
3. Efficiency of CHP system: Electric efficiency- $\eta_{elec.}$ (~35%-45%)
   Heat / Thermal efficiency- $\eta_{heat.}$ (~ 40%-50%)

[27] 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2: Energy

Table 8: Default Combustion Emissions of Biomethane and Fossil Gas

Combustion	Biomethane [28]	Fossil Gas [29]
CO_2 (kg CO_2e)	0	53.99
CH_4 (kg CO_2e)	0.1	0.025
N_2O (kg CO_2e)	0.03	0.024
%CH_4	99%	99%
HHV - GJ/m^3	0.0393	0.0358
EF- Kg CO_2e / GJ	0.13	54.035

4.4. Electricity Use Emissions (EU)

Indirect Emissions

Indirect emissions from the use of electricity onsite to produce gaseous biofuel must be calculated.

(EU) Electricity Use Emissions: The amount of electricity consumed in the production process is measured in kilowatt-hours (kWh). Gaseous biofuel production requires electricity, and the next sections details the treatment of electricity in the GHG CI of the production process. AD plants have auxiliary systems such as digester mixers, feedstock pumps and gas compressors which require electricity. The power requirement of these auxiliary systems is referred to as the parasitic load. Electricity is typically generated on site or used from the grid.

4.4.1. Grid Electricity (location based) Emissions

Location based grid emissions factors can be used per MFEs latest publication relative to the year of production. Emissions factors for electricity grid shall be NZ specific (MFE) and aligned with the closest time period for which the annual LCA assessment is completed. Electricity EFs should be applied on a quarterly basis to acknowledge seasonal fluctuations in the grid as well as in the temporal accuracy of gaseous biofuel production.

4.4.2. Supplier Specific Electricity Emissions (Market Based) - REC's

Gaseous biofuel producers can use Supplier Specific Electricity Emissions where there is an approved contractual instrument in place. Contractual instruments include energy attribute certificates, renewable energy certificates (RECs), guarantee of origin (GOs) or green energy certificates. It is recommended that the product LCA contain dual reporting where electricity REC's have been used to reduce product carbon footprint.

[28] Australia National Greenhouse Accounts Factors 2024 based on HHV / GCV
[29] MFE default for natural gas.

Per ISO 14067, Life cycle data from a supplier-specific electricity product can be used when the supplier is able to guarantee through a contractual instrument that the electricity product,

1. Conveys the information associated with the unit of electricity delivered together with the characteristics of the generator,
2. Is assured with a unique claim,
3. Is tracked and redeemed, retired or cancelled by or on behalf of the reporting entity,
4. Is as close as possible to the period to which the contractual instrument is applied and comprises a corresponding timespan.

4.5. Fugitive Emissions (FE_T)

Fugitive emissions are the direct GHG emissions that escape during the production process, of gaseous biofuel. These direct emissions can occur from the below sources,

1. Anaerobic digester leakage, (FE_{ad})
2. Fugitive emissions during scrubbing biogas and upgrading to biomethane, (FE_{su})
3. Digestate storage. (FE_{ds})

Equation 7: $$FE_T = FE_{ad} + FE_{su} + FE_{ds} (kgCO_2e)$$

4.5.1. Anaerobic Digester Fugitive Emissions (FE_{ad})

An anaerobic digester will leak a portion of the produced biogas and these **digester leakage emissions** (FE_{ad}) must be included in the calculation of the CI of biogas or biomethane for production pathways that involve an anaerobic digester. Fugitive emissions for the AD process can be estimated using a default factor from the US GREET model. Estimate default fugitive emissions rates are in Table 10 below.

4.5.2. Upgrading to Biomethane Fugitive Emissions (FE_{su})

Fugitive methane emissions occur in the process of upgrading biogas to biomethane and must be accounted for in the RNG CI value calculations (FE_{su}). Default values from the US GREET model can be used (See appendix B for default values).

Table 9: Fugitive Emissions Default Values

Process	Parameter (CH_4)	Defaults	Units	Sources
WWTP- AD	Fugitive CH_4	0.001 - 0.006	kg CH_4 /kg biogas	GREET, 2020
AD	Fugitive CH_4	0.01	Kg CH_4 /kg biogas	GREET, 2020
LFG	Fugitive CH_4	032F[30]	kg CH_4 /kg biogas	GREET, 2020
Biogas - RNG upgrading				
MDEA / MEA Scrubbing	Fugitive CH_4	1.98E-05	kg CH_4 /MJ RNG	
Water Scrubbing	Fugitive CH_4	1.96E-04	kg CH_4 /MJ RNG	GREET, 2020

[30] LFG fugitive emissions are captured in the BAU scenario and excluded from CI of biogas/ biomethane.

Fugitive emissions are highly sensitive to the assumptions or data used to estimate fugitive emissions impacts. Measuring loss rates of biogas from the system boundary should be a priority to ensure accuracy of the results.

To increase the accuracy of the RNG CI calculation fugitive emissions can be calculated using primary data in alignment with the Canadian CFR specifications.

Calculating fugitive emissions from upgrading:

The below equations for calculating fugitive emissions from upgrading are gleaned from the Canadian Clean Fuel Regulations.[31]

There are three alternative methods of calculating FE_{su} pending on available metering. Consequently, if fugitive emissions are captured and directed to destruction equipment, such as a flare, a quantity may be subtracted from the direct emissions.

Equation 8 Gas flow and methane concentration before after upgrading is metered

$$FE_{su} = \frac{\left(F_{biogas} \times \%CH_{4\ Biogas} - F_{BM} \times \%CH_{4\ BM}\right) \times 0.671 \times 1000}{\text{Total fuel volume}}$$

Equation 9 Biogas flow and methane concentration before upgrading is metered only

$$FE_{su} = \frac{\left(F_{biogas} \times \%CH_{4\ Biogas}\right) \times 0.671 \times 1000 \times ER_{Fugative}}{\text{Total fuel volume}}$$

Equation 10 Biomethane flow and methane concentration after upgrading is metered only

$$FE_{su} = \frac{\frac{\left(F_{BM} \times \%CH_{4\ BM} \times 0.671 \times 1000\right)}{1 - ER_{Fugative}} - \left(F_{BM} \times \%CH_{BM} \times 0.671 \times 1000\right)}{\text{Total fuel volume}}$$

Equation 11 Captured fugitive emissions destroyed

$$FE_{sud} = FE_{su} - FE_{destroyed}$$

$$FE_{distroyed} = \frac{\left(F_{captured} \times \%CH_{4\ captured}\right) \times \text{Distruction factor} \times 0.671 \times 1000}{\text{Total fuel volume}}$$

FE_{su} = Upgrading to biomethane
F_{biogas} = flow biogas (m^3/day)
F_{BM} = flow biomethane (m^3/day)
$F_{captured}$ = flow of fugitive emissions captured (m3/day)
$ER_{Fugative}$ = default fugitive emissions rate for the relevant waste feedstock type based on

[31] 2024, Environment and Climate Change Canada, Fuel life cycle assessment model methodology

Canadian CFR LCA methodology they are:

- 2% for landfill gas
- 2% for livestock manure
- 1% for municipal solid waste
- 1% for wastewater treatment sludge

4.5.3. Storage Fugitive Emissions (FE_{ds})

If digestate is not being stored onsite for a period greater than 4 months in an anaerobic condition, then this factor can be omitted[32]. Digestate storage emissions mainly arises from methane produced by remaining volatile solids (VS) within an anaerobic environment.

To accurately calculate Digestate storage emissions, digestate flow, % volatile solids (VS), and biochemical methane potential (BMP) must be measured at the outlet of the digester. There is a significant GHG impact for digesters with a low residence time and high percentage of volatile solids and/or BMP. If digestate is being used as a co-product it is recommended that the producer sample the digestate volatile solids and biochemical methane potential following PAS 110:2014[33].

Emissions vary based on several factors, including duration of storage, temperature, storage conditions, and digestate composition. This methodology uses a formula adapted from IPCC 2019 Guidelines for National Greenhouse Gas Inventories, Ch 6 - Wastewater:

Measuring key parameters:

a. **Storage Duration**: Longer storage times can increase the fugitive emissions.

b. **Storage Conditions**: Covered or uncovered storage impacts fugitive emissions, as does ambient temperature. Below formula assumes that digestate is covered to avoid contamination and dilution from rain[34].

c. **Digestate Characteristics**: BMP = Maximum methane-producing capacity of the digestate (m^3 CH_4/kg VS). BMP default value is 0.48 m^3 CH_4/kg VS

d. **Volatile Solids (VS) Content**: Indicates the organic matter in digestate that can still degrade and emit methane. (kg)

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[32] Delay time in CH4 production for solid waste is 6 months (+/- 2months), based on 2006 IPCC Guidelines for National GHG Inventories, Volume 5, Section 3.2.3

[33] PAS110:2014 Specification for whole digestate, separated liquor and separated fibre derived from the anaerobic digestion of source-segregated biodegradable materials

[34] PAS 110- Covers might influence the impact on digestate of climatic factors, such as rainfall, in the dilution, wetting and slumping of product.

Equation 12: $FE_{ds} = VS \times BMP \times MCF$

VS = Volatile solids in digestate (kg)
BMP = Maximum methane-producing capacity of the digestate (m^3 CH_4/kg VS)
MCF = Methane correction factor based on storage type and climate

Table 10: Digestate storage defaults[35]

Storage type	Details	MCF	BMP (kg CH_4/kg VS)
Anaerobic shallow lagoon	Depth less than 2 metres, use expert judgment.	0.8	0.48
Anaerobic deep lagoon	Depth more than 2 metres	0.2	0.12

4.6. Emissions from Consumables Used (CU)

Indirect emissions for the use of consumables (CU) should be calculated based on primary or secondary data. Consumable emissions should include the upfront embodied emissions (lifecycle stages A1-A3, raw material supply, transportation of raw material and production of product) and the transportation of the products to the user. These emissions can be found within the EPD (Environmental Product Declaration) of products and also EF databases like Ecoinvent. Some consumables may be very small quantities relative to the overall emissions of the Biofuel and may be deemed de minimum once they are quantified.

The following are examples of AD consumables:

- Activated carbon filter media, used for biogas cleaning
- Ferric hydroxide or ferric chloride chemical, used for hydrogen sulphide mitigation
- A range of engine/lubrication oils
- Chemicals for pH control i.e. sodium hydroxide or hydrochloric acid
- Chemicals for industrial cleaning i.e. sodium hydroxide “caustic”
- Trace nutrients for feeding the AD biology i.e. trace metals
- Water use, either in process or for wider site, and depending on location, may have an associated carbon impact.

4.7. Waste Emissions (W)

Waste Emissions (W) are calculated based on the details of the biofuel production waste products. These production waste streams include digestate, sludge, packaging and any other byproduct of the process. The waste emissions depend on how the waste streams are managed, including any emissions from transportation and offsite waste treatment processes. Ministry for the Environment Measuring Emissions: A guide for organisations – 2024 provide emission factors for waste disposal.

[35] IPCC 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories 6.19, TABLE 6.3 (UPDATED)

4.8. Pipeline Transmission and Distribution Emissions (T&D)

Pipeline Distribution Losses are fugitive emissions which sit beyond the cradle to gate boundary but within the cradle to grave emissions of RNG. Fugitive emissions are based on the overall pipeline network performance. Transmission and Distribution (T&D) losses in the NZ pipeline network can be calculated based on MFE default values per kWh or GJ of pipeline spec RNG added to the network.

If an entity consumes reticulated RNG, related natural gas transmission and distribution losses emissions are categorised under Scope 3, Category 3 based on the GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard.

Table 12[36] details the emission factors for the transmission and distribution losses for reticulated natural gas. These represent an estimate of the average amount of carbon dioxide equivalents emitted from losses associated with the delivery (transmission and distribution) of each unit of gas consumed through local distribution networks in 2022. They are average figures and therefore make no allowance for distance from off-take point, or other factors that may vary between individual consumers.

Table 11 T&D Losses (adapted from MFE GHG measurement guide)

Transmission & Distribution Losses Source	Unit	kg CO_2e/unit	CO2/unit (kg CO_2e)	CH4/Unit (kg CO_2e)	N2O/unitu(kg CO_2e)
Natural gas used	kWh	0.00723	0.00006	0.00717	n/a
	GJ	2.01	0.0175	1.99	n/a

5. EMISSIONS ALLOCATION TO CO-PRODUCTS

In allocation accounting, the emissions are split between co-products. Co-product allocation is "*partitioning the input or output flows of a process or a product system between the product system under study and one or more other product systems*" [ISO 14044: 2006].

Based on ISO 14044, and the GHG Protocol Product Life Cycle Accounting and Reporting Standard allocation approach should be avoided by further sub-dividing the system to isolate co-products. If allocation cannot be avoided, an allocation method should be based on mass, energy content or economic value. [37]

This methodology applies an energy-based allocation to the biomethane product carbon intensity. The main reason for an energy-based allocation is to ensure consistency and comparability of the biomethane CI with other fuels. **In this approach the carbon impacts of the co-products are applied to the gaseous biofuel while the CO_2 and digestate co-products have a zero emissions carbon intensity.**

[36] Measuring emissions: A guide for organisations: 2024 detailed guide
[37] ISO 14044 Lifecycle Assessment

Energy-based allocation is required or is default approach for International biomethane REC Schemes such as the European Energy Certificate System (EECS) REDcert methodology, the World Biogas Association Carbon Intensity methodology and aligned with the Canadian Clean Fuel Regulations (CFR).

In alignment with the Canadian CFR, if a production facility produces biomethane or biogas using multiple feedstock types (e.g., wastewater sludge and solid organic wastes), then the gaseous biofuel must first be separated into portions corresponding to each feedstock type to calculate one CI value for each distinct fuel portion produced. In these cases, the allocation procedure must be used to allocate the various inputs to the different portions of biomethane or biogas.

5.1. Heat and Electricity Co-products

Heat and Electricity are common co-products from the combined heat and power (CHP) produced on the bioenergy production site from combustion of the gaseous biofuel. An energy allocation approach is recommended for the carbon footprint of these co-products.

The combustion emissions factor for biogas depends on the energy density (CH_4/m^3) and the Higher Heating Value (HHV) (GJ/m^3). This can be calculated relative to the published emissions factor for biomethane.

5.1.1. Electricity Co-product Carbon Intensity ($CI_{electricity}$)

Equation 13 $CI_{elect} = CI_{biogas} \times (\eta_{elect} / \eta_{CHP})$ $[kg\ CO_2e/GJ\ of\ electricity]$

CI_{biogas} – Carbon Intensity of Biogas (upstream cradle to gate) - kg CO_2e / GJ
η_{heat} - Heat / Thermal efficiency - %
η_{elect} - Electricity conversion efficiency - %
η_{CHP} - CHP efficiency %

5.1.2. Heat Co-product Carbon Intensity (CI_{heat})

Equation 14: $CI_{heat} = CI_{biogas}\ x\ (\eta_{heat} / \eta_{CHP})$ $[kg\ CO_2e/GJ\ of\ heat]$

CI_{biogas} – Carbon Intensity of Biogas (upstream cradle to gate) - kg CO_2e / GJ
η_{heat} - Heat / Thermal efficiency - %
η_{elect} - Electricity conversion efficiency - %
η_{CHP} - CHP efficiency %

5.2. Digestate application to land

Digestate is the spent contents of an anaerobic digester, which can be used as a fertiliser. Digestate may be liquid, semi-solid or solid. Digestate may be further stabilized aerobically (e.g. composted), applied to land, sent to a solid waste disposal site (SWDS), or kept in a storage or evaporation pond[38]. It contains nutrients and organic matter that can contribute to soil health and soil carbon content. When applied to land, digestate helps build up soil organic carbon (SOC), improving soil structure, fertility, and water retention building climate change resilience on land.

Digestate application to land is excluded from the Biomethane CI because it is a co-product and therefore outside the LCA boundary. Digestate is treated as a zero carbon co-product in the energy allocation method chosen in this methodology (see section 4). All of the emissions to create the digestate are allocated to the Biomethane CI. The application of digestate to land is therefore outside of the Cradle to Gate LCA boundary of RNG CI measurement.

Digestate application to land often create an avoided emissions relative to synthetic fossil fuel based fertilisers. The GHG Protocol have draft guidance on accounting land sector application of biogenic fertilisers and SOC [39] which could be useful for future development of an avoided emissions methodology for digestate replacing synthetic fertiliser.

Digestate displacing synthetic fossil-based fertiliser creates avoided emissions and has potential to create carbon credits. See the American Biogas Association carbon accounting methodology and the accompanying research document[40] informing this methodology for more details on avoided emissions.

6. CARBON INTENSITY REPORTING

6.1. Transparency, Assumptions, and Level of Uncertainty

The Carbon Intensity LCA Report should provide a level of transparency to show what assumptions and variables are “embedded” within the emissions factors, activity data, default values and calculations following this methodology. This should include visibility on how much primary data vs secondary data the calculations rely on. This will help with appreciating the level of uncertainty of the Carbon Intensity LCA analysis.

Uncertainty is a measure of any potential inaccuracy, bias, or incompleteness of an emissions factor. Ideally default factors should have low uncertainty. Level of uncertainty should be disclosed within the calculations.

6.2. Project Monitoring Best Practice:

The impacts of project activities on relevant emission sources, sinks, and reservoirs (SSR) must be monitored to determine the gaseous biofuel CI. For those purposes, a monitoring plan shall

[38] American Biogas Association; Carbon Accounting Methodology for Biogas, 2024
[39] https://ghgprotocol.org/land-sector-and-removals-guidance
[40] Literature Review – Methods for accounting for the Carbon Intensity of Biomethane

be established for all monitoring and reporting activities associated with gaseous biofuel Producer[41].

The monitoring plan should provide,

1. Parameters to be measured and details (i.e., units, description, acquisition frequency). This is referred to in GHG accounting as Primary data.
2. The frequency of instrument field checks, calibration activities, and data acquisition.
3. The role of individuals performing each specific monitoring activity.
4. The details about the data management system and the flow of raw data to the final report.
5. The process of Biomethane Control System (BCS) activities, digestate separation, and end use.
6. Process Flow Diagram (PFD) showing system boundary, inputs and outputs, and location of meters.
7. The usage of fossil fuels for project activities.
8. Electricity usage.
9. The equipment and frequency of gas generation and methane-content recording.
10. Records of calibration and verification of measurement equipment.
11. The process for recording data and QA/QC procedures for such.

Table 13 below provides the list of relevant parameters to be monitored under this methodology in alignment with the American Biogas Association Methodology. Primary data requirements are the measured data (M) and are highlighted.

[41] American Biogas Association; Carbon Accounting Methodology for Biogas, 2024

Table 12: Gaseous Biofuel Plant parameters to be measured and monitored

Parameter	Unit	Description	Frequency	Calculated (C), Measured (M), Reference (R)	Records / Meter Placement
M_F – Mass Feedstock	kg	Mass of Feedstock, % dry solids.	Per Feedstock Type	M + R	Weighbridge mass and % dry solids. DOC can be referenced from Table 18
F_E -Feedstock Energy Density	CH_4/kg,	Calculated from DOC and MCF	Per Feedstock Type	C	Equation 4 – Feedstock Energy.
F_{bg} – Flow Biogas	m^3/day	Biogas flow from AD to refinement	Daily	M	Continuous flow Meter prior to upgrading (@ 101.3kPa, 15℃)
Biogas CH_4 content	% CH_4	Methane content of Biogas flow from AD	Daily	M	Methane Sensor – before upgrading
BG_{CH4} - Biogas Methane Production	m^3 CH_4	Methane Production Emissions	Monthly	C	Calculated from above measurements.
F_{bm} – Flow of RNG	m^3/day	RNG flow	Daily	M	Continuous flow Meters after upgrading and pressurisation to pipeline. (@ 101.3kPa, 15℃).[42]
BM_{CH4} - Biomethane methane content	% CH_4	Methane content of RNG flow downstream of upgrading	Daily	M	Methane Sensor – After upgrading
EU – Electricity Use	kWh	Electricity used on site	Monthly	M	Utility bills Electricity meter . Electricity REC certificates as required.
FU – Fossil Fuel Use	Volume and energy density.	Fossil fuels used	Monthly, per type of fossil fuel.	M	Utility bills and gas meters.
FE – Fugitive Emissions	m^3	Fugitive emissions	Annually or Default /Calculated	M / C	Default per Table 10 or Site assessment (IR camera, methane sensors, LDAR[43] survey)
VS- Volatile Solids Digestate	kg	Digestate Mass measurement % volatile solids	Annual if Digestate is being stored on site over 4 months.	M	Flowmeter, or Volume, or Mass measurements.

[42] Volumes to be at the standardised temperature and pressure
[43] LDAR is Leak Detection and Repair Survey

Parameter	Unit	Description	Frequency	Calculated (C), Measured (M), Reference (R)	Records / Meter Placement
BMP - biochemical methane potential Digestate	BMP	Digestate BMP measurement	Annual if Digestate is being stored on site over 4 months.	M or C	BMP - A default value of 0.48 m^3 CH_4/kg VS

Flow meters, sampling devices, and gas analyzers shall be subject to regular maintenance, testing, and calibration to ensure accuracy according to regulatory required frequency and manufacturer's recommendations. Relevant parameters shall be monitored as indicated in Table 13 above.

7. CRITICAL REVIEW AND RECORD KEEPING

A critical peer review of the LCA should be carried out by a suitably qualified person. In such a case, an expert independent of the LCA shall perform the review. The review statement, comments of the LCA practitioner and any response to recommendations made by the LCA reviewer shall be included in the LCA report.[44]

7.1. Mass Balance, Energy Balance & Activity Data

Mass and energy balancing checks are required for many of the international REC schemes to ensure accurate tracking and verification of renewable energy production. These balances help confirm that the reported energy output (electricity, heat, or biomethane) corresponds correctly to the feedstock input and that system losses are accounted for.

An independent critical peer review on data validity should be conducted during the process of data collection to confirm and provide evidence that the data quality requirements specified in Table 6: Gaseous Biofuel GHG Activity Data and Data Quality, have been met.

Peer review should involve calculating mass and energy balances with comparative analyses between feedstock energy input and gaseous biofuel energy output. As each unit process obeys the laws of conservation of mass and energy, mass and energy balances provide a useful check on the validity of the description and quantification of a unit process.

The mass balance system must include both information on the input/output of raw materials and fuels for which the above sustainability characteristics have been determined (sustainably certified raw materials and fuels) and information on the input/output of raw materials and fuels, including fossil fuels, for which no sustainability

[44] ISO 14044:2006 Environmental management — Life cycle assessment — Requirements and guidelines

characteristics have been determined. This applies only to raw materials used to produce biofuels, bioliquids and biomass fuels and to finished fuels that can be produced from these raw materials.

7.2. Producer Record-Keeping

For independent critical review and historical documentation, project developers should keep all information outlined in this methodology for 10 years after it is generated. This information will not be publicly available but may be requested for verification. System information the project developer should retain includes:

1. Data inputs for GHG-reduction assessments.
2. Copies of all permits relevant to project activities.
3. Biogas flow meter information, including model number, serial number, calibration procedures, etc.
4. Methane monitoring information.
5. Destruction device monitoring information.
6. Calibration results for all meters.
7. Biogas flow and methane content data.
8. Feedstock data.
9. Results of CO_2e reduction calculations.
10. Initial and subsequent verification records and results.
11. Maintenance records of the Biogas Control System (BCS) and monitoring equipment.

7.3. Energy Balancing:

The energy of the biofuel produced comes from the feedstock which is the renewable organic waste diverted from other processes. Energy balance can be assessed by calculating the energy of the feedstock compared to the energy of the biofuel produced. The below data should be recorded to allow for energy balancing of the system.

1. **Type of Feedstock**: Information on the type of waste biomass used (e.g., food waste, agricultural residues, wastewater sludge).
2. **Mass of Feedstock (M_F)**: The amount of each biomass input, shall be measured in kilograms or tonnes. **(%DS)** Total dry solids to be recorded.
3. **Source of Feedstock**: Details and documentation on where the feedstock is sourced from, including transportation distances.
4. **Renewable Feedstock**: Feedstock must meet the requirements of Biogenic Waste outlined in section 2.5.
5. **Degradable organic carbon (DOC).** DOC is the percentage of volatile solids based on the mass of dry solids.
6. **DOC_f-** the fraction of degradable organic carbon that decomposes under anaerobic conditions.

7. **DS Dry Solids (%)**. The percentage of dry solids is the percentage of organic waste mass without water/moisture relative to the mass of the waste with water /moisture content.
8. **Extraction Emissions (**E_x**):** any energy and emissions associated with extraction of the feedstock from the BAU process.
9. **Determine Feedstock CH_4 Density** (F_{CH4}): CH_4/kg,
10. **Energy Balance Check:** Estimate Feedstock energy from mass input to AD

Mass and Energy Balance Calculation:

To derive the mass and energy balance of an AD facility the CH_4 must be estimated for the biodegradable portion of the feedstock. This should be done via a detailed calculation to estimate the CH_4/kg of feedstock. Alternatively, energy density of the feedstock can be determined via a default table in Appendix.

Default Method:

The default EFs for solid waste come from MFE for waste to landfill without gas recovery. (see Default EFs in appendix A).

Detailed Method:

The detailed calculation method suggested below is based on the IPCC Guidelines for solid waste disposal[45]. If the variables are unknown / unmeasured then defaults can be chosen as per the below Table and Appendix A.

1. Wastewater feedstock should be recorded by percentage of total solids. (typically 5% or 30% Total Solids (TS) or Dry Solids (DS))
2. Municipal biogenic and other organic waste should be broken down by category in alignment with MFE (typically, Food, Garden, Paper, Wood (combined), Wood (treated), Wood (untreated), Textile, Nappies, Sludge, Inert)[46]
3. Organic waste degradable organic carbon (DOC) shall be determined

Equation 15:[47] $$\text{Energy Feedstock} = F_{CH4} \times M_F \times HHV_{CH4}\ [MJ]$$ [48]

F_{CH4}= DOC x DOC_f x F x MWR [CH4/kg] Table 13
MF = Mass of feedstock
HHV_{CH4} = Higher Heating Value Table 13

[45] IPCC 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Ch. 3, Solid Waste Disposal
[46] MFE, Measuring emissions: A guide for organisations: 2024 detailed guide
[47] Adapted from 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 3 SWD, Equation 3.2 & 3.3

Table 13: Variables for calculating Energy of Feedstock

DOC	Degradable organic content	Value	Source
DOC	Degradable organic content	varies	Appendix B - Table 17
DOC_f	fraction of DOC decomposed under anaerobic conditions	50%	IPCC default
F	fraction of gas that is methane	50%	IPCC default
MWR	Molecular Weight Ratio CH_4/C	1.333333	IPCC
GWP_{CH4}	Global Warming Potential biogenic CH_4	28	CO_2e
HHV_{CH4}	Higher Heating Value	0.0398 GJ/m^3	IPCC 2006, Vol. 2, Table 1.2

8. RNG REPORTING WITHIN THE USER GHG INVENTORY

Reporting within the users GHG inventory should be based on ISO 14064-1[49] Organisational GHG reporting standard and / or the GHG Protocol Reporting standard. Currently, the GHG Protocol does not provide explicit guidance on how companies should use RNG REC certificates to account for GHG emissions savings achieved by procuring gaseous biofuels.

This methodlogy aligns to ISO 14064-1; Direct CO_2 emissions from combustion of biofuel, are quantified and reported separately from anthropogenic emissions and are not aggregated to the total absolute annual emissions. Direct CH_4 and N_2O emissions associated with biofuel combustion should be reported as anthropogenic emissions in the inventory.

This methodology acknowledges that there is currently a work stream within the GHG Protocol called “Actions and Market Instruments” that will provide additional guidance on Market-based Accounting Approaches which may effect this guidance document.

This methodology advises reporting in alignment with the latest guidance from the UK Green Gas Certificate Scheme[50]. If a company purchases biogas or RNG through a contractual instrument that meets the GHG Protocol Scope 2 Quality Criteria[51], it can then report Scope 1 emissions for gaseous biofuel using the market-based method and using the product specific Carbon Intensity. The reporting company can report emissions from gaseous biofuel in alignment with the below requirements:

[49] 14064-1:2018, Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals

[50] GGCS Guidance Document 15 Use of Green Gas Certification Scheme within the GHG Protocol Version 1.5 – September 2022

[51] GHG Protocol Scope 2 Criteria required expert interpretation as it is currently written for renewable electricity certificates.

1. Direct Scope 1 biogenic CO_2 emissions linked to the use of gaseous biofuel are zero[52]
2. Direct biogenic emissions from other GHGs (CH_4 and N_2O) still need to be reported as part of a Scope 1 emissions.
3. Upstream emissions of gaseous biofuel production and transport must be reported as part of Scope 3 emissions and this data needs to be included on the certificate provided by the certification scheme.
4. Biogenic emissions need to be reported in the organisational GHG Inventory, but separately from the scopes in a memo item.
5. Unlike with Electricity, companies do not need to provide dual reporting for use of gaseous biofuel REC’s.

Producers of gaseous biofuel shall report the Cradle to Gate product carbon intensity as aligned with the requirements of this methodology. The LCA gate is at the pipeline network, post biogas scrubbing/ upgrading, compression and injection into the pipeline network.

Users of gaseous biofuel require full LCA Cradle to Gate and Gate to Grave emissions to align with Organisational GHG inventory reporting as per below Table 14:

Table 14 Users Organisational GHG inventory reporting of gaseous biofuel

User Emissions	GHG P Category	Gaseous Biofuel System Boundary	Product LCA
Indirect Upstream emissions (Well to tank)	Scope 3, Cat.3	Upstream = $(CI_{biofuel}) \times V_{biofuel}$	Cradle to Gate
Indirect Upstream Emissions	Scope 3, Cat.3	Downstream = $T\&D_{GHG}$	Gate to Grave
Direct Emissions	Scope 1	Combustion	Gate to Grave

Cradle to Gate emissions satisfies user organisational emissions reporting GHG Protocol, Scope 3, Category 3, Indirect emissions of the fuel and is often referred to as upstream well to tank (WTT)[53].

Gate to grave emissions includes Transmission and Distribution (T&D) losses and the combustion of the gaseous biofuel. Combustion emissions satisfy user organisational emissions reporting of direct emissions, GHG Protocol, Scope 1, Category 1. T&D emissions satisfy user emissions reporting GHG Protocol, Scope 3, Category 3 indirect emissions.

[52] Aligned with ISO 14064-1, Direct CO 2 emissions from combustion of biomass and biofuel, as well as composting activities, are quantified and reported separately from anthropogenic emissions. Direct CH4 and N2O emissions associated with biomass combustion should be reported as anthropogenic emissions in the inventory.
[53] Corporate Value Chain (Scope 3) Accounting and Reporting Standard

9. DEFINITIONS

For the purpose of this methodology, the following definitions apply:

Activity Data: Greenhouse gas (GHG) activity data is the quantitative measure of activity that results in a greenhouse gas emission or removal.

Allocation: partition of input or output flows of a process between the product system under study and one or more other product systems (ISO 14040).

Anaerobic digester - equipment that is used to generate biogas from liquid or solid waste through anaerobic digestion. The digester is covered or encapsulated to enable biogas capture for flaring, heat and/or power generation or feeding biogas into a natural gas distribution system. The following types of digesters are considered:

(i) Covered anaerobic lagoons: anaerobic lagoons that are covered with a flexible membrane to capture methane produced during the digestion process. Covered anaerobic lagoons are typically used for high volume effluent such as animal manure and organic industrial effluent like starch industry effluent;

(ii) Conventional digesters: digesters that are operated similar to a covered anaerobic lagoon, with no mixing or liquid and biogas recirculation;

(iii) High rate digesters, such as up-flow anaerobic sludge blanket (UASB) reactors, anaerobic filter bed reactors and fluidized bed reactors;

(iv) Two stage digesters: anaerobic digestion takes place in a two stage process, solubilization of particulate matter occurs and volatile acids are formed in the first stage digester. The second stage is carried out in a separate digester, at a neutral pH and a longer solid retention time;

Anaerobic digestion - degradation and stabilization of organic materials by the action of anaerobic bacteria that result in production of methane and carbon dioxide. Typical organic materials that undergo anaerobic digestion are municipal solid waste (MSW), animal manure, wastewater, organic industrial effluent and bio-solids from aerobic wastewater treatment plants;

Biogas - gas generated from a digester via anaerobic digestion. Typically, the composition of the gas is 50-70% CH_4 and 30-50% CO_2, with traces of H_2S and N_2O (1% -5%).

Biomass - biomass is non-fossilized and biodegradable organic material originating from plants, animals and microorganisms. This includes products, by-products, residues and waste from slaughterhouses, cattle-raising, agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes. Biomass also includes gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material;

Biochar - Biochar is produced by pyrolysis, a process that heats biomass (such as wastewater sludge, wood, or agricultural waste) in the absence of oxygen. This process converts organic carbon in the biomass into a stable, solid form of carbon that resists decomposition. Unlike the raw biomass, which would naturally degrade and release CO_2 back into the atmosphere, biochar remains in the soil for hundreds to thousands of years.

Carbon Intensity: in relation to gaseous biofuel fuel, this means the quantity of CO_2e in grams or kilograms that is released during the activities conducted over the fuel's life cycle per megajoule or gigajoule of energy of the fuel. The carbon footprint per unit of energy of the fuel based on the lifecycle stages and specific inputs and outputs of the production.

Carbon Equivalent: A measurement that standardises the climate impacts of different GHGs.

Composting - a process of biodegradation of waste under aerobic (oxygen-rich) conditions. Waste that can be composted must contain solid biodegradable organic material. Composting converts biodegradable organic carbon to mostly carbon dioxide (CO_2) and a residue (compost) that can be used as a fertilizer. Other outputs from composting can include, inter alia, methane (CH_4), nitrous oxide (N_2O), and run-off wastewater (in case of co-composting);

Cradle-to-gate: scope of a carbon intensity which covers all life cycle stages up to the production facility gate.

Cradle-to-grave: scope of a carbon intensity which covers the full life cycle.

Digestate - spent contents of an anaerobic digester. Digestate may be liquid, semi-solid or solid. Digestate may be further stabilized aerobically (e.g. composted), applied to land, sent to a solid waste disposal site (SWDS), or kept in a storage or evaporation pond;

Digestate to Biochar: The solid fraction of digestate from the AD process can be used as feedstock for biochar production. This converts digestate into a stable carbon-rich material, further sequestering carbon and enhancing the nutrient retention of biochar.

Emission Factor - A coefficient relating GHG activity data with the GHG emission intensity value.

Gaseous Biofuel – Low Carbon clean fuel from organic waste which includes Biogas and Biomethane/ RNG.

Global warming potential - index, based on radiative properties of GHGs, measuring the radiative forcing following a pulse emission of a unit mass of a given GHG in the present-day atmosphere integrated over a chosen time horizon, relative to that of carbon dioxide (CO_2)

Lifecycle Assessment - compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product system throughout its life cycle (ISO 14040).

Materiality – Within this methodology materiality is a word to describe if a GHG source or sink is significant enough to include in the gaseous biofuel CI. A source is material if it is of significant magnitude (>1%) or if the producer has an ability to influence those emissions. A source or sink can also be material if it is significant to the sector or key stakeholders of the GHG information.

Organic waste - waste (fresh waste, animal waste, wastewater) that contains degradable organic matter. This may include, for example, domestic waste, commercial waste, animal manure, wastewater, organic industrial waste (such as sludge from wastewater treatment plants) and MSW;

Solid waste disposal site - designated areas intended as the final storage place for solid waste. Stockpiles are considered a SWDS if: (a) their volume to surface area ratio is 1.5 or larger; and if (b) a visual inspection by the DOE confirms that the material is exposed to anaerobic conditions (i.e. it has a low porosity and is moist);

Upgraded biogas – biogas upgraded to natural gas quality.

Unit process: Smallest divisible activity of a life cycle. It transforms quantities of inputs into quantities of outputs. It can use modelling parameters and background data.

Flow: Material or energy stream entering (input) or leaving (output) a unit process. "Elementary flows" refer to exchanges between a unit process and the environment (i.e. extractions and emissions) while "intermediate flows" refer to exchanges between unit processes (e.g., electricity).

Life cycle stage: Specific part of a life cycle (e.g., feedstock production). Life cycle stages are modelled by a collection of unit processes.

Fuel pathway: Collection of unit processes, modeling parameters, and background data which represents the life cycle of a fuel from a given feedstock. In general LCA vocabulary, a fuel pathway is called a product system.

System process: Process that contains the lifecycle information of a group of unit processes.

Waste-to-energy: the conversion of waste into power, heat, or biofuels.

Verification: The process of evaluating a client claim with past historical data to determine it is materially correct and conforms to predetermined criteria." Footnote: Verification is ISO language and is not used by financial auditors. [Source: Adapted ISO 14064-3]

10. ACRONYMS

11. For this methodology, the following acronyms apply

BCS	Biogas control system
BMP	Biochemical Methane Potential
CH_4	Methane
CI	Carbon intensity
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOC	Degradable organic carbon
EF	GHG emission factor
GHG	Greenhouse gas
GWP	Global warming potential
LCA	Lifecycle assessment
LCFS	Low carbon fuel standard
LDAR	Leak Detection and Repair (survey)
LFG	Landfill gas
MSW	Municipal solid waste
MCF	Methane Correction Factor
N_2O/NO_X	Nitrous oxide
PE	Production emissions (biogas production stage)
PFD	Process Flow Diagram
RNG	Renewable natural gas (Biomethane)
SSR	Sources, sinks, and reservoirs
SWDS	Solid waste disposal site
T&D	Transmission and Distribution
VS	Volatile Solids
WWTP	Wastewater treatment plant
WtE	Waste to Energy
WTT	Well to Tank
WTW	Well to Wheel

12. APPENDIX A

International reference REC/ LCFS schemes and methodologies

Jurisdiction	Scheme Name	CI methodology / model	Functional Unit	System Processes Covered (LFG, WWTP, AD)	System Boundary	Allocation	Verification	Avoided Emissions	Methodology Alignment
Europe	**European Energy Certificate System EECS** EECS | AIB	Renewable Energy Directive II (RED-II). REDcert standards. 2023 Scheme principles for GHG calculation - Version EU 06 Logo REDCERT	grams of CO2 equivalent per MJ of biofuel/bioliquid/ biomass fuel [gCO2eq/MJ]. Use lower heating value (LHV) into the unit gCO2eq/MJ of final fuel	Generic	Cradle to Grave, Feedstock extraction/ transportation to RNG combustion.	Energy Allocation	Annual	Not addressed.	Mass Balance, Sustainable Feedstock, Calculation.
UK	**UK Green Gas Certification Scheme (GGCS)**	2024, Emissions Reporting - Certificates - Green Gas Certification Scheme	gCO2e / MJ (measured as net calorific value / LHV)	Generic	Cradle to Grave; Includes end use combustion	Energy Allocation	Annual	Not addressed.	REC Producer/ User reporting. CI less than = 34.8 kg CO_2e/GJ
Canada	**Canada's Clean Fuel Regulations (CFR)**	2024, Environment and Climate Change Canada, Fuel life cycle assessment model methodology. Fuel Life Cycle	1 MJ of energy content based on the Higher Heating Value (HHV) delivered to the end user and	Generic	Cradle to Grave; Includes end use combustion	Energy Allocation	Annual	Not required. Calculated separate to CI.	Default Values and Fugitive emissions., Exclusions, PDF requirements

Jurisdiction	Scheme Name	CI methodology / model	Functional Unit	System Processes Covered (LFG, WWTP, AD)	System Boundary	Allocation	Verification	Avoided Emissions	Methodology Alignment
		Assessment Model - Canada.ca	used for its energy content.					Optional Reporting.	
USA	American Biogas Association;	2024, Carbon Accounting Methodology for Biogas American biogas council	grams of CO2e per megajoule (MJ) of fuel (LHV) or grams of CO2e per kilowatt hour (kWh) depending on the end-use	Methodologies for WWTP, LFG and Food / Organic to AD.	Cradle to Grave; Includes end use combustion	Energy Allocation (primary); System Expansion (Mass, Economic Value) if cant be avoided.	Annual	Covered	Avoided emissions, Data Quality Measurement requirement, frequency. Upstream boundaries.
World Biogas Association	International Anaerobic Digestion Certification Scheme	2024, International Anaerobic Digestion Certification Scheme, Life Cycle Assessment LCA Guidance for AD	grams of CO2 equivalent per MJ of biofuel/bioliquid/ biomass fuel [gCO2eq/MJ]. Use lower heating value (LHV) into the unit gCO2eq/MJ of final fuel	Generic	Cradle to Gate;	Energy Allocation (primary; secondary use System Expansion (Mass, Economic Value)	Silent	Not covered.	Cradle to Gate Boundary
California	**California's Low Carbon Fuel Standard (LCFS),**	2024 CA-GREET 4.0 (under consultation), CA-GREET 3.0, LCFS Life Cycle Analysis Models and Documentation |	g CO2e / MJ - HHV	Methodologies for WWTP, LFG and Food / Organic to AD.	Cradle to Grave; includes Cradle to Gate, Gate to tank, tank to wheel.	Energy Allocation	Annual	Calculated separate to CI.	Many transportation fuel types. Hydrogen, BioOil to RNG. DOC Default, Well to Wheel LCA, LHV Default.

Jurisdiction	Scheme Name	CI methodology / model	Functional Unit	System Processes Covered (LFG, WWTP, AD)	System Boundary	Allocation	Verification	Avoided Emissions	Methodology Alignment
		California Air Resources Board							
USA	**U.S. Renewable Fuel Standard (RFS)**	GREET T1, US EPA GREET | Department of Energy Renewable Fuel Standard Program | US EPA	g CO_2e / MJ - HHV	Generic.	Cradle to Grave; includes Cradle to Gate, Gate to tank, tank to wheel.	Energy Allocation	Annual	Calculated separate to CI.	Many transportation fuel types. Hydrogen, BioOil to RNG. Well to Wheel LCA, LHV Default.
Australia	**Greenpower Renewable Gas Certification**	2024 - RGGO Scheme – certifier / auditor Renewable Gas Certification - Rules V2.0.pdf	Kg CO_2e / GJ - HHV	“Technology agnostic”	Cradle to Gate	Energy Allocation, Expansion if other products (sold)	Annual	NO	Must use Renewable electricity. REC. Materiality: 1% individual, 5% cumulative.

13. APPENDIX B

Default Factors :

Table 15 : 2022, A Comparative Life Cycle Evaluation of the Global Warming Potential (GWP) Impacts of Renewable Natural Gas Production Pathways (supporting information) , Comparative Life Cycle Evaluation

Process	Parameter	Input/ Output	Value	Units	Sources
Animal Manure – Anaerobic Digestion					
Anaerobic Digestion	Feedstock	Input	3.83	lb/MJ biogas	(ANL, 2020)[1]
	Electricity	Input	0.01	kWh/MJ biogas	(ANL, 2020)[1]
	Heat	Input	0.14	MJ/MJ biogas	(ANL, 2020) [1]
	Biogas	Output	1	MJ biogas	
	Digestate	Output	0.13	lb residue/MJ biogas	(ANL, 2020) [1]
	Methane Leak	Output	4.41E-04	lb CH4/MJ biogas	(ANL, 2020) [1]
Biogas Cleaning and Upgrading	Biogas	Input	1.20	MJ biogas/MJ RNG	(ANL, 2020) [1]
	Electricity	Input	0.01	kWh/MJ RNG	(ANL, 2020) [1]
	RNG	Output	1	MJ RNG	
	Methane Leak	Output	5.28E-04	lb CH4/MJ RNG	(ANL, 2020) [1]
Landfill Gas – Anaerobic Digestion					
Landfill Gas Cleaning and Upgrading	Biogas	Input	0.03	kg/MJ RNG	(ANL, 2020) [1]
	Electricity	Input	0.01	kWh/MJ RNG	(ANL, 2020) [1]
	RNG	Output	1	MJ RNG	
	Methane Leak	Output	3.26E-04	kg/MJ RNG	(ANL, 2020) [1]

Process	Parameter	Input/ Output	Value	Units	Sources
Municipal Solid Waste – Anaerobic Digestion					
Anaerobic Digestion	Feedstock	Input	4.29	kg/kg biogas	(ANL, 2020) [1]
	Electricity	Input	1.67	kWh/kg biogas	(ANL, 2020) [1]
	Heat	Input	1.59	MJ/kg biogas	(ANL, 2020) [1]
	Biogas	Output	1	kg biogas	
	Digestate	Output	0.97	kg/kg biogas	(ANL, 2020) [1]
	Methane Leak	Output	0.01	kg/kg biogas	(ANL, 2020) [1]
Biogas Cleaning and Upgrading	Biogas	Input	0.03	kg/MJ RNG	(ANL, 2020) [1]
	Electricity	Input	0.01	kWh/MJ RNG	(ANL, 2020) [1]
	RNG	Output	1	MJ RNG	
	Methane Leak	Output	3.26E-04	kg/MJ RNG	(ANL, 2020) [1]
Wastewater Sludge – Anaerobic Digestion					
Anaerobic Digestion	Feedstock	Input	40.96 - 78.93	kg/kg biogas	(ANL, 2020) [1] (Lee et al., 2016)[2] (Mills et al., 2014)[3]
	Electricity	Input	0.12 - 0.20	kWh/kg biogas	(ANL, 2020) [1] (Lee et al., 2016) [2] (Mills et al., 2014) [3]
	Heat	Input	5.10 - 8.20	MJ/kg biogas	(ANL, 2020) [1] (Lee et al., 2016) [2] (Mills et al., 2014) [3]
	Biogas	Output	1	kg biogas	

Process	Parameter	Input/ Output	Value	Units	Sources	Process
Anaerobic Digestion	Digestate	Output	6.91 - 7.36	kg/kg biogas	(ANL, 2020) [1] (Lee et al., 2016) [2] (Mills et al., 2014) [3]	
	Methane Leak	Output	0.001 - 0.006	kg/kg biogas	(ANL, 2020) [1] (Lee et al., 2016) [2] (Mills et al., 2014) [3]	
Biogas Cleaning and Upgrading	MDEA Scrubbing	Biogas	Input	0.03 - 0.05	kg/MJ RNG	(Gamba et al., 2014)[4] (Starr et al., 2012)[5]
		Electricity	Input	0.01	kWh/MJ RNG	(Starr et al., 2012)[5]
		Heat	Input	4.24E-05	MJ/MJ RNG	(Gamba et al., 2014)[4]
		RNG	Output	1	MJ RNG	
		Methane Leak	Output	1.98E-05	kg/MJ RNG	(Starr et al., 2012)[5]
	MEA Scrubbing	Biogas	Input	0.03 - 0.05	kg/MJ RNG	(Gamba et al., 2014)[4] (Starr et al., 2012)[5] (ANL, 2020) [1]
		Electricity	Input	0.006 - 0.007	kWh/MJ RNG	(Starr et al., 2012)[5] (ANL, 2020) [1]
		Heat	Input	4.25E-04	MJ/MJ RNG	(Gamba et al., 2014)[4]
		RNG	Output	1	MJ RNG	

Process	Parameter		Input/ Output	Value	Units	Sources
Biogas Cleaning and Upgrading	MEA Scrubbing	Methane Leak	Output	1.98E-05 - 1.62E-04	kg/MJ RNG	(Starr et al., 2012)[5] (ANL, 2020)[1]
	Water Scrubbing	Biogas	Input	0.03 - 0.05	kg/MJ RNG	(Gamba et al., 2014)[4] (Starr et al., 2012)[5] (ANL, 2020)[1]
		Electricity	Input	0.007 - 0.011	kWh/MJ RNG	(Starr et al., 2012)[5] (ANL, 2020)[1]
		RNG	Output	1	MJ RNG	
		Methane Leak	Output	1.64E-04 - 1.96E-04	kg/MJ RNG	(Starr et al., 2012)[5] (ANL, 2020)[1]
RNG Compression	Combusted Natural Gas		Input	1.00E-04	kg/MJ compressed RNG	(NETL, 2012)[12]
	RNG		Input	1	MJ RNG	(NETL, 2012)[12]
	Compressed RNG		Output	1	MJ compressed RNG	(NETL, 2012)[12]

Section S6 References

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Table 16 Upstream WTT emission factors for fuels and electricity (New Zealand)

Source: Agrilink New Zealand fuel and electricity total primary energy and life cycle greenhouse gas emission factors 2022 - July 2022. August 2023

Table 2 Summary of fuel energy and life cycle emission factors

Fuel type	Unit	Fugitive Energy Coefficient	GHG[2] – 2007 (gCO_2e/ unit)	GHG[2] – 2007 (gCO_2e/ unit)[3]	GHG[2] – 2007 (gCO_2e/ unit)
					WTT - Upstream Emissions
GHG Protocol Scope			1 & 3	1	
Diesel	litres	1.21	3,147	2,689	458
Petrol (regular unleaded)	litres	1.21	2,760	2,341	419
Biodiesel (tallow) †	kg	0.50	1,750	-	-
Light fuel oil	litres	1.21	3,415	2,930	485
Marine diesel oil	litres	1.21	3,342	2,879	463
Bunker/Heavy fuel oil	litres	1.21	3,539	3,046	493
Intermediate fuel oil	litres	1.21	3,520	3,030	490
Heavy fuel oil (electricity)	litres	1.21	3,498	3,007	491
Aviation gasoline	litres	1.21	2,634	2,230	404
Natural Gas (Commercial)	MJ	1.13	60.7	53.8	7
LPG	kg	1.13	3,313	2,972	341
Coal (bituminous)	kg	1.02	2,761	2,607	154
Coal (sub-bituminous)	kg	1.02	2,068	1,955	113
Coal (lignite)	kg	1.02	1,512	1,433	79

Upstream emissions split by GHG gas

	Unit	kg CO2-e	CO2 (kg CO2)	CH4 (kg CO2-e)	N2O (kg CO2-e)
Diesel - Upstream	litre	0.458	0.455255049	0.001750766	0.000994185
Petrol (regular unleaded) - Upstream	litre	0.419	0.401388829	0.005345835	0.012265336
Light fuel oil - Upstream	litre	0.485	0.48224573	0.00175671	0.00099756
Heavy fuel oil - Upstream	litre	0.493	0.490256926	0.001749569	0.000993505
Aviation gasoline - Upstream	litre	0.404	0.400856007	8.09E-05	0.003063081
Natural Gas distributed commercial - Upstream	MJ	0.0069	0.006880901	1.61E-05	3.04E-06
Natural Gas distributed industry - Upstream	MJ	0.0069	0.006893737	3.22E-06	3.05E-06
Coal - Bituminous - Upstream	kg	0.154	0.152895909	0.000456303	0.000647788
Coal - Sub-Bituminous - Upstream	kg	0.113	0.112214868	0.000324483	0.000460649
Coal - Lignite - Upstream	kg	0.079	0.07845766	0.000224141	0.0003182
LPG - Upstream	litre	0.341	0.332583838	0.008104529	0.000311632
LPG stationary commercial - Upstream	kg	0.341	0.340092458	0.000763098	0.000144444
LPG stationary industry - Upstream	kg	0.341	0.340702404	0.000152893	0.000144703
Electricity - Upstream	kWh	0.0073	0.007032144	0.000260243	7.61E-06

Table 17 DOC Degradable Organic Carbon Values (from American Biogas Association Carbon Accounting Methodology for Biogas, 2024)

Landfill Waste Type	DOC (Weight Fraction, Wet Basis)
All bulk waste, unseparated	0.2028
Bulk MSW	0.3
Construction and demolition waste	0.08
Diapers	0.24
Food waste	0.15
Food processing industry waste	0.22
Garden waste	0.2
Inert waste	0
Other industrial solid waste	0.2
Paper waste	0.4
Pulp and paper industry waste	0.2
Sewage sludge	0.05
Textile waste	0.24
Wood and/or straw waste, wood products	0.43

Table 18 MFE 2024 and Australia National Greenhouse Accounts Factors 2024

Emission source		Unit	kg CO_2e	CO_2 (kg CO_2e)	CH_4 (kg CO_2e)	N_2O (kg CO_2e)	Uncertainty	Source
Combustion	Natural Gas	GJ	54.035	53.98607	0.02520	0.02385	CO2e ± 2.4%, CO2 ± 2.4%, CH4 ± 50%, N2O ± 50%	MFE 2024

Emission source		Unit	kg CO_2e	CO_2 (kg CO_2e)	CH_4 (kg CO_2e)	N_2O (kg CO_2e)	Uncertainty	Source
Combustion	biomethane (99% CH4 @ 101.1kpa &15C)	GJ	0.130	0	0.1	0.03		Australia 2024

Waste to landfill without gas recovery emission factors								
Emission source		**Unit**	**kg CO_2e**	**CO_2 (kg CO_2e)**	**CH_4 (kg CO_2e)**	**N_2O (kg CO_2e)**	**Assumption**	**Uncertainty**
Waste (known composition)	Waste - Food	kg	2.107	n/a	2.107	n/a	N2O and CO2 are excluded	±40%
	Waste - Garden	kg	1.724	n/a	1.724	n/a	N2O and CO2 are excluded	±40%
	Waste - Paper	kg	3.064	n/a	3.064	n/a	N2O and CO2 are excluded	±40%
	Waste - Wood (combined)	kg	1.187	n/a	1.187	n/a	N2O and CO2 are excluded	±40%
	Wood (treated)	kg	0.192	n/a	0.192	n/a	N2O and CO2 are excluded	±40%
	Wood (untreated)	kg	2.681	n/a	2.681	n/a	N2O and CO2 are excluded	±40%
	Waste - Textile	kg	1.532	n/a	1.532	n/a	N2O and CO2 are excluded	±40%
	Waste - Nappies	kg	0.766	n/a	0.766	n/a	N2O and CO2 are excluded	±40%
	Waste - Sludge	kg	0.479	n/a	0.479	n/a	N2O and CO2 are excluded	±40%
	Waste - Other (Inert)	kg	n/a	n/a	n/a	n/a	N2O and CO2 are excluded	±40%
Waste (unknown composition)	General waste	kg	0.724	n/a	0.724	n/a	N2O and CO2 are excluded	Not quantified
	Office waste	kg	2.081	n/a	2.081	n/a	N2O and CO2 are excluded	Not quantified

Non municipal waste								
Emission source		**Unit**	**kg CO_2e**	**CO_2 (kg CO_2e)**	**CH_4 (kg CO_2e)**	**N_2O (kg CO_2e)**	**Assumption**	**Uncertainty**
Waste (known composition)	Biological (sludge)	kg	0.196	n/a	0.196	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Construction & Demolition	kg	0.157	n/a	0.157	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Bulk Waste	kg	1.098	n/a	1.098	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Food	kg	0.588	n/a	0.588	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Garden	kg	0.784	n/a	0.784	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Industrial	kg	0.588	n/a	0.588	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Wood	kg	1.333	n/a	1.333	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Inert (all other waste)	kg	n/a	n/a	n/a	n/a	N2O and CO2 are excluded	IPCC uncertainties
	Average for non-municipal solid waste	kg	0.197	n/a	0.197	n/a	N2O and CO2 are excluded	IPCC uncertainties

This is a simplification of the IPCC FOD model as it ignores the time decay of waste and instead calculates the total emissions that will result

IPCC_Waste_Emissions
Calculation method

Transmission and distribution losses								
Emission source			**Unit**	**kg CO_2e**	**CO_2 (kg CO_2e)**	**CH_4 (kg CO_2e)**	**N_2O (kg CO_2e)**	**Uncertainty**
Transmission and distribution losses		Natural gas used	kWh	0.007	0.00006	0.00717	n/a	Unknown
		Natural gas used	GJ	2.009	0.01747	1.99160	n/a	Unknown

14. APPENDIX C

Precision and uncertainty in emissions calculation models, An Explainer, Toitū